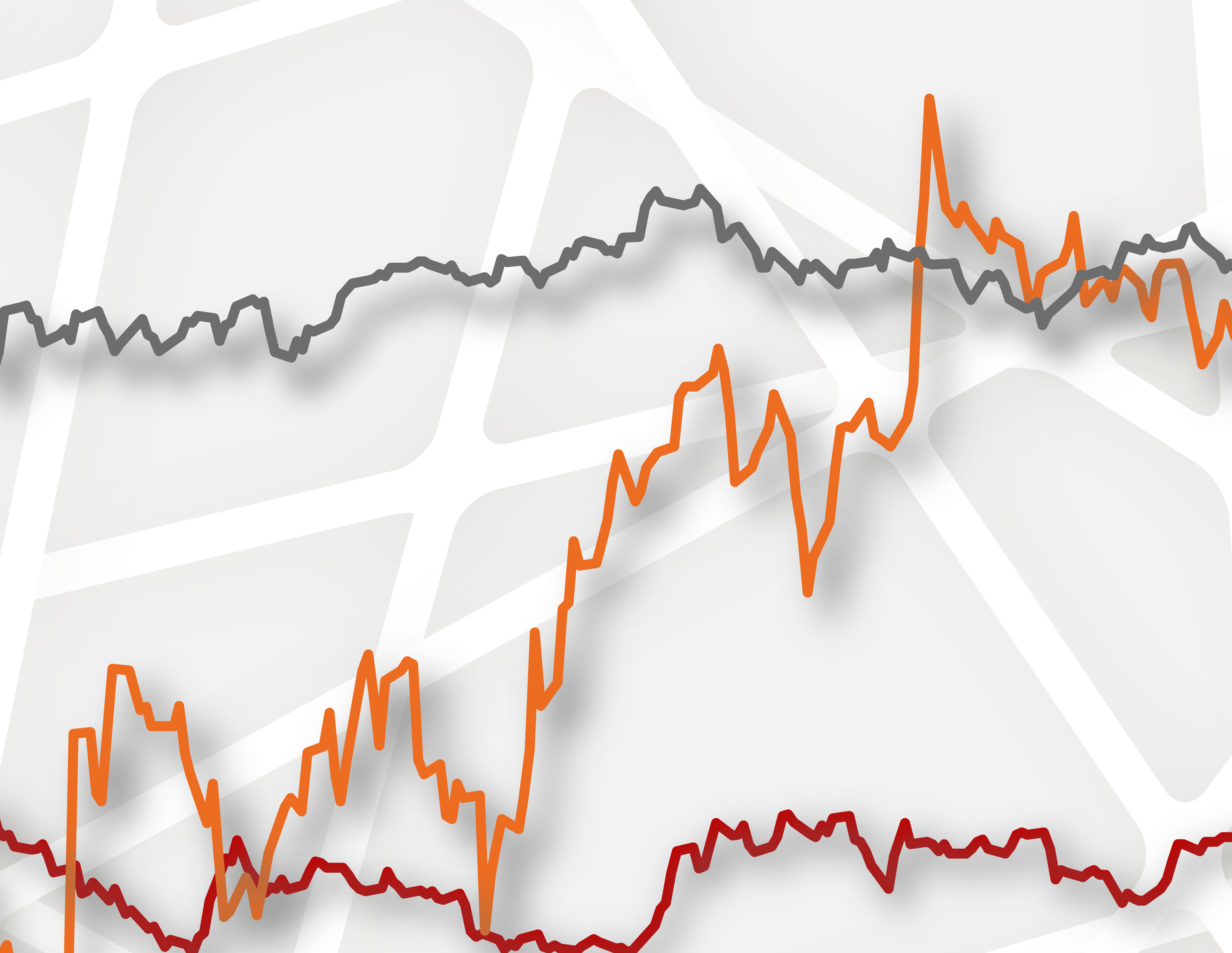

REKK REGIONÁLIS ENERGIAGAZDASÁGI KUTATÓKÖZPONT

HUNGARIAN ENERGY MARKET REPORT

Q2-3 2016

Dear Reader,

This is a special double edition of the REKK Quarterly comprised of more and longer articles than the normal publication. Following an overview of energy markets in the first half of 2016, the write-ups go further in depth on a range of pressing issues: the improving profitability of natural gas-fired power plants, the impact of coutry-level carbon price floors being considered across Europe, the latest on renewable support schemes, Gazprom's European gas pricing strategy, and prospects for electricity storage.

Sustained low European natural gas prices have made gas-fired power plants more competitive in electricity generation in Hungary. Just as the load factor of several domestic gas-fired power plants has started to grow, electricity imports over the last year and a half have subsided. Although coal fired plants remain more profitable, the gap between the clean dark and clean spark spreads has narrowed considerably. This article provides detailed insight into the effect of falling gas prices on Hungary's electricity consumption portfolio in the last one and a half year.

However the relative competitiveness of European power plants is more affected by EUA prices than the actual fuel prices. The extraordinarily low EUA price is a threat to the EU climate commitments which has raised the issue of reforming the EU Emission Trading System (EU ETS). In response, some member states have propose the introduction of a carbon price floor. The second article looks at these current developments and the possible impact of carbon price floors in fuel-switching.

The third article summarizes a REKK conference held between 7 and 9 June focusing on four hot button topics in renewable-based electricity production. It gives an overview of regional country-level developments towards 2020 and 2030 carbon reduction targets, including plans and challenges of new auctioning procedures, and assesses the new Hungarian support scheme „METÁR" to be introduced next year.

The fourth article looks at the trend and outlook for Gazprom's natural gas pricing strategy. In 2016 European natural gas prices hit a historical low as demand stagnated, and yet Russian gas exports to Europe have continued to rise even in these market conditions.

The last article considers the implications of growing renewable-based and primarily weather-dependant electricity production and storage needed to facilititate the sector's decarbonisation, as well as regulatory issues related to the new storage technologies. The coming issues of REKK Quarterly will include several articles on such topics of critical importance to the European Commission's new electricity market model.

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ERRA course: Energy efficiency and regulation 2017

In March 2017 ERRA (Energy Regulators Regional Association) and REKK will hold a two-day intensive course on the current questions of energy efficiency and regulation. The promotion of energy efficiency has traditionally not been the task of energy regulators. Since energy efficiency policies are wide-ranging horizontal policies, it is often the energy ministry or a specialised government authority that is in charge of implementation. These roles, however, are changing. It is increasingly recognized that certain decisions of energy regulators (e.g. on final consumer prices or the remuneration of network companies) significantly impact the energy efficiency related decisions of energy companies and consumers. Moreover, energy regulators are more involved in the implementation of government energy efficiency programs.

The objective of the two-day training event is to provide a detailed introduction into tasks of the regulator that are relevant to meeting the energy efficiency policy objectives.

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Energy market developments

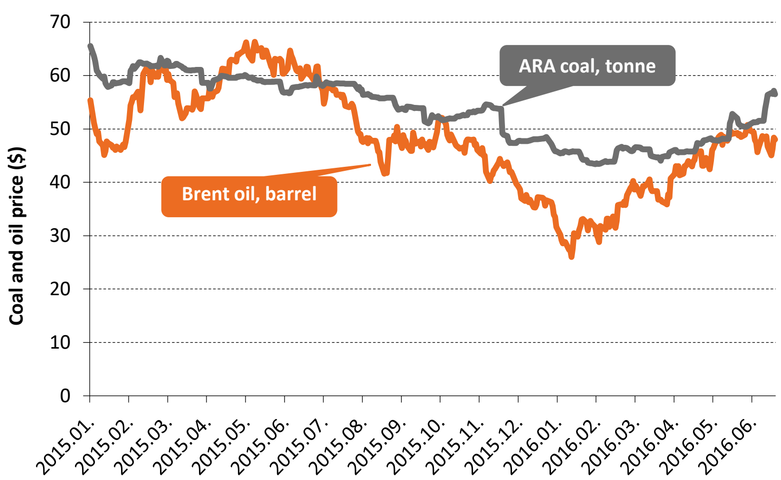
The first quarter of 2016 saw a rise in global oil and coal prices along with a drop in EUA prices. Since changes in gas prices lag behind oil prices in oil-linked contracts, the first half of 2016 saw a yearly 22% rise in Russian exports to Europe. Year-ahead baseload and peak EEX futures plummeted in the first three months of the year. Even so, the profitability of gas-fired power plants improved marginally with gas and EUA prices falling. Like other countries in the region, Hungary witnessed a significant fall in electricity prices at the beginning of the year that rallied in the second quarter, raising the half-yearly average HUPX price above EEX by 12.2 EUR/MWH, which is 3 EUR higher than the same period a year ago. There was a significant growth in Ukrainian gas exports from 1.9 to 2.7 bcm as oil-linked imports became cheaper, while trade on the Austrian-Hungarian interconnector increased considerably as well. According to REKK estimations, there was not any significant difference between the recognized purchase costs of universal service providers and the effective Ukrainian import prices calculated on the basis of Eurostat data in the second quarter of 2016.

International price trends

Following the slide in energy prices in the second half of 2015, crude oil prices clawed back in the first quarter of 2016, which eventually transmitted to the European power market. Brent prices sank to a low of 26 USD in January and closed in June at 48 USD, an 84% increase. In the same period coal prices also increased, with monthly average ARA prices up 15% between January and June (Figure 1).

Henry Hub hit a several-year low at 1.7 USD/MMBtu in March owing to the high storage reserves/stock resulting from the mild winter and record-setting American gas production in February. In April there was a significant drop in the spot prices of LNG transported to Japan (Figure 2) due to the delayed price cutting effect of oil-linked agreements and weakening demand. Eclipse Energy estimates that the Japanese demand, which fell last year by 4% to 85 million tons, would slide to 80 million tons this year. Japan's current long-term agreements of total 71 million tons, implying a purchase of only 9 million tons on the spot market.

Figure 1 Prices of month-ahead EEX ARA coal and Brent crude oil spot prices



Source: CME, IEA

At the same time, the LNG supply to the Asia-Pacific region is rapidly growing. Australia's largest resource development project the 54 billion USD Gorgon LNG launched its first delivery to Japan in March. The capacity of this multiphase project will total 15.6 million tons per year. In May, Australia Pacific LNG Train 2 and Gladstone LNG Train 2 started production (3.9-3.9 mt annual capacity), while three more facilities are likely to be commissioned next year (Wheatstone, Prelude and Ichthys amounting to a total capacity of 21.4 mt).

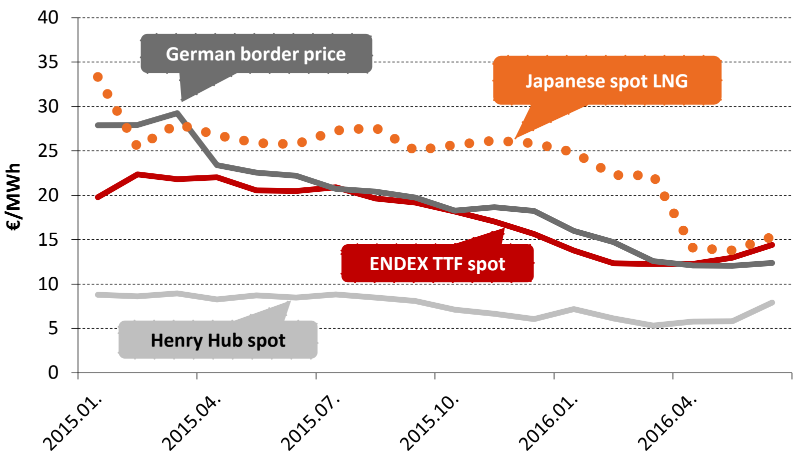
Due to the protracted decline in oil prices until the beginning of 2016, German border prices of Russian long-term contracted gas also continued to fall in 2016. At the end of March, Uniper (now operating the fossil fuels portfolio of E.ON) made an agreement with Gazprom for the adjustment of long-term contract prices. In May the head of Gazprom Export made it clear that the company would offer price flexibility in order to remain competitive in European markets. Then in June the financial head of Gazprom revised down the estimated average export price from 199 to 170 USD/thousand cm, which approaches the 2016 Q3 futures prices of the NGC hub. Gazprom's European sales averaged 234 USD/thousand cm in 2015. In addition, Gazprom announced that it will repeat auctions between 31 August and 2 September at the same entry points of last year's September auction (Greifswald, GASPOOL, Olbernhau), and on Baumgarten as well as on the Austrian-Italian border (Arnoldstein). Favorable Russian gas prices and maintenance works hindering Norwegian production resulted in a considerable annual growth of 22% in Russian gas exports to Europe in the first half of 2016.

The more than 50% fall in oil-linked gas prices that began in March 2015 was tracked by TTF prices until April when increasing oil prices and Norwegian outages helped push spot prices beyond 14 EUR/MWh in June, more than 2 EUR above the German border price. Prices were also influenced by the uncertainty surrounding Groningen output and decision of the Dutch government on the production cap at the end of June. In the end markets were relieved with the government's decision to limit production to 24 bcm over the next five years with the possibility to boost production to 30 bcm in the case of a cold winter. The limit for the 2015/16 gas year is 27 bcm.

EEX year-ahead peak and baseload futures plummeted in the first quarter of 2016 (Figure 3). This was precipitated by EUA prices that exceeded 8 EUR/t in January and fell below 5 EUR/t, more than 40% over 1.5 months. Following a momentary upswing, EUA prices closed in June at under 5 EUR/t. The deterioration of the European steel industry and the phase-out of coal-based power generation in Great-Britain drove down EUA prices. At the same time carbon intensive German power production was considerably weaker due to the abnormally mild and windy December. Furthermore, at the beginning of the year, Poland created additional uncertainty on the EUA market by filing a complaint against the EU Court of Justice over the previous year's agreement on the market stability reserve (MSR).

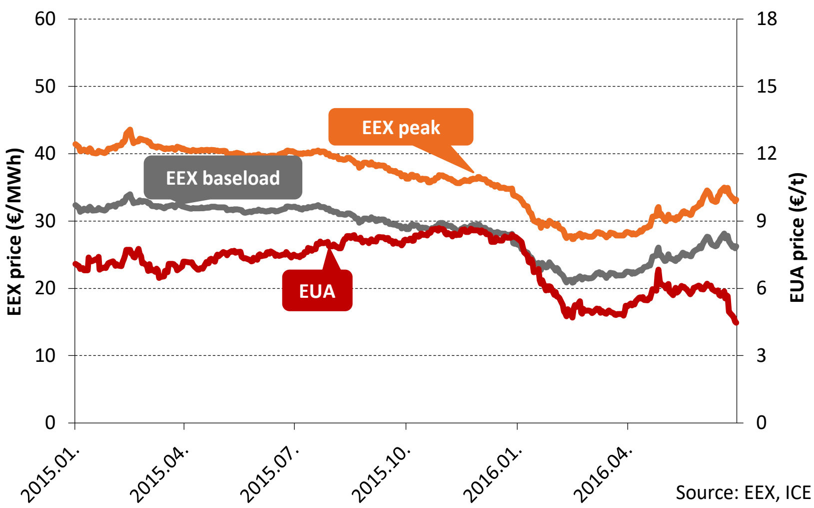
Rising coal and oil prices, the pending French carbon tax on non-ETS sectors (See page 16), and limited German nuclear capacities owing to maintenance works resulted in a rise in second quarter EEX futures. The more than 10% quarterly increase was the highest since 2011. The average German baseload price of 27 EUR/MWh was still 15% lower than the June 2015 average. With forecasted power demand of the German steel and automotive industries set to stall, 2017 German baseload futures hit a nearly 15-year low with prices sinking under 21 EUR/MWh. However, the planned

Figure 2 Prices on select international gas markets from January 2015 to June 2016



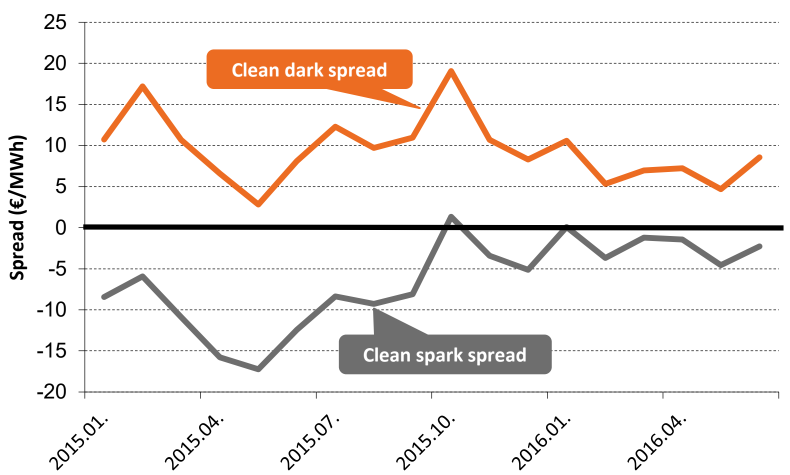
Source: Statistical Office of Japan, EIA, Gaspool, IMF

Figure 3 Prices of EEX year-ahead futures and CO_2 allowances (EUA) with December delivery from January 2015 to June 2016



Source: EEX, ICE

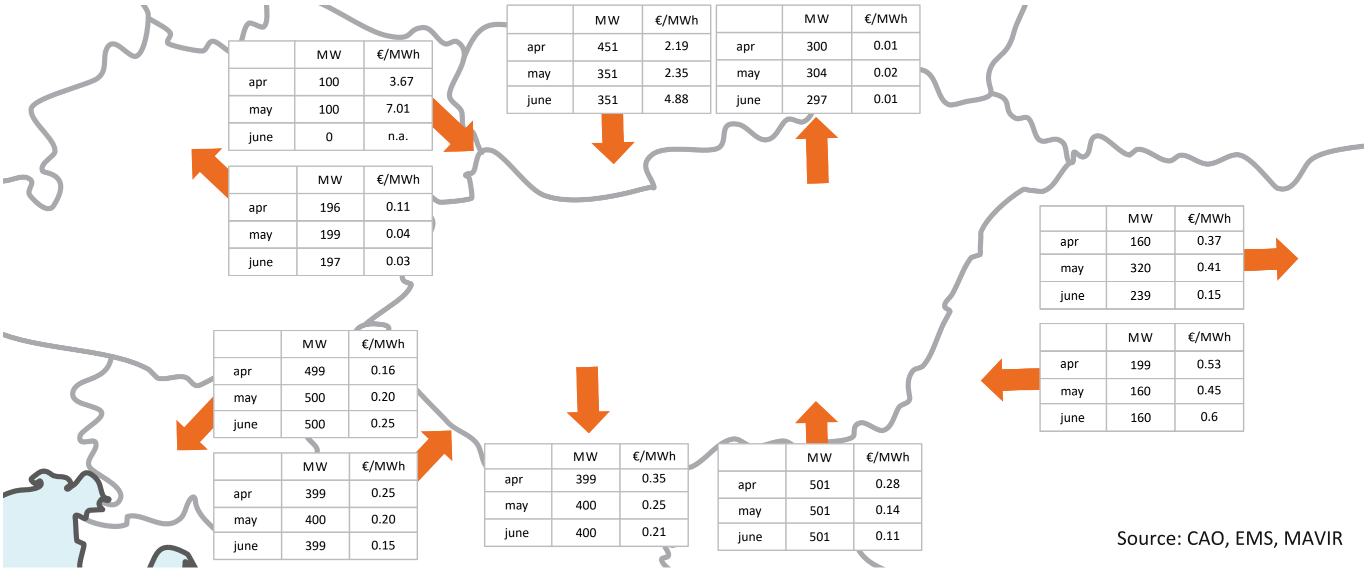
Figure 4 Clean spark spread (gas fired power plants) and clean dark spread (coal fired power plants) on German market from January 2015 to June 2016



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

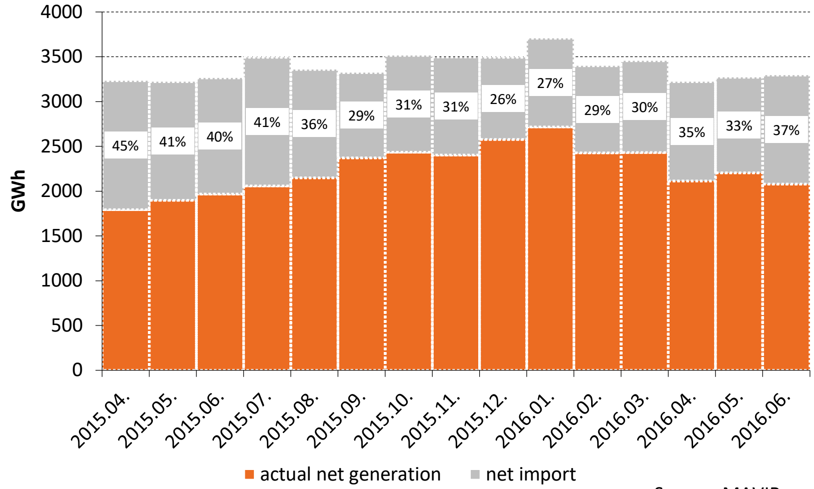
Note: Both indicators show the difference between electricity prices on exchanges and the cost of electricity generation, where the cost of production is added up by the cost of gas (spark spread) or coal (dark spread) needed for generating 1 MWh of electricity and the additional cost of CO_2 emission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

Figure 5 Results of monthly cross-border capacity auctions in Hungary, Q2 2016



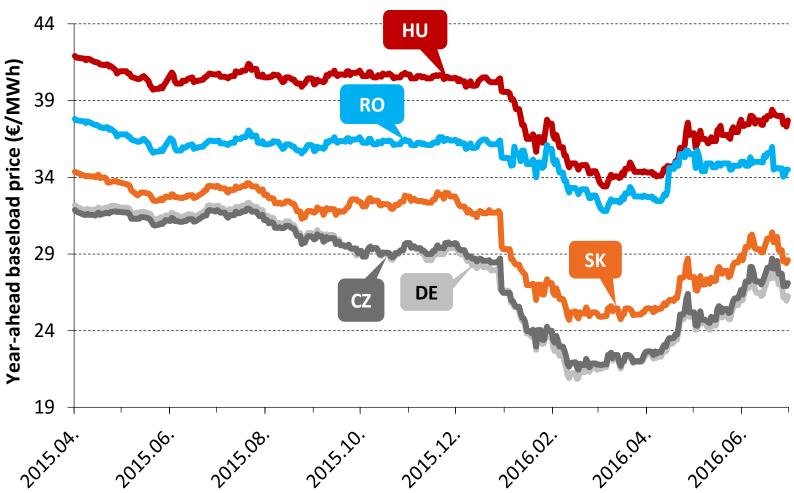
Source: CAO, EMS, MAVIR

Figure 6 Hungary's net electricity production and monthly net electricity imports between April 2015 and June 2016



Source: MAVIR

Figure 7 Year-ahead baseload futures prices between April 2015 and June 2016



Source: EEX, PXE

phase-out of German nuclear energy, which led to the surmise of the 1345 MW Grafenrheinfeld facility in June, could cause a surge on the German power market in the long term. German nuclear energy production was down 29% from the same period of the previous year, hitting a record low of 4.85 TWh in June. Simultaneously German coal and gas power plants increased their outputs by 6 TWh to nearly 150 TWh in the first half of 2016.

The clean spark spread was steady between -5 and 0 EUR/MWh after briefly reaching positive territory in January. An Uniper spokesman said the renegotiated long-term Russian gas import agreement will positively affect German gas-fired power plants, the majority of which are in reserve and hardly operate. EWI calculated that if German gas-fired power plants can buy gas at the spot price, the new state-of-the-art CCGT power plants could only compete with the old coal-fired power plants with 33-35% efficiency. REKK estimates are based on higher efficiency coal and lower efficiency gas-fired power plants (See Note below Figure 4). German gas-fired power plant operators say that they would need 25-30 EUR/t EUA prices in order to be able to compete with coal-fired power plants.

Even though the profitability of coal-fired power plants declined, the clean dark spread remained in the black. Still the difference between the two spreads fell from 21 EUR/MWh in the first half of 2015 to 9 EUR/MWh in the first half of 2016 on the average.

Overview of domestic power market

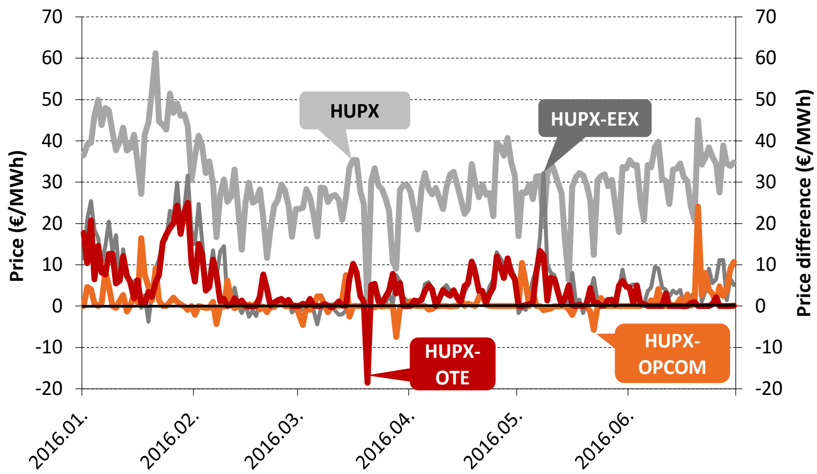
For the second quarter of 2016, the Austria interconnector was the most expensive source of imports at over 7 EUR for 1 MWh in May. Since system operators did not offer any capacity on this intersection in June, the capacity fee for 1 MWh of Slovakian imports almost doubled to nearly 5 EUR compared to the May price. Import capacity fees remained under 1 EUR/MWh on the other intersections in last quarter as well. (Figure 5)

Domestic electricity consumption in the first half of the year was 1% more than the previous year at 20.31 TWh. However, with greater utilization of gas-fired power plants (See page 12) production grew by 7% leading to a decline in the share of net imports from 36% to 32% (calculated average of January-June) (Figure 6).

Following the regional trend, Hungary witnessed a significant drop in electricity prices at the beginning of the year. The HUPX year-ahead baseload futures declined from 40 EUR/MWh a year ago to 34 EUR/MWh by March (Figure 7). This is attributable to the mild weather and sufficient water levels in the Balkans. In the second quarter prices on the Hungarian market rebounded, averaging nearly 38 EUR/MWh in June. As a result, the HUPX-EEX spread reached 12.2 EUR/MWh over the six month period, which is 3 EUR more than last year. The HUPX/EEX spread on day-ahead markets was 5.7 EUR/MWh practically identical to the same period in 2015 (Figure 8).

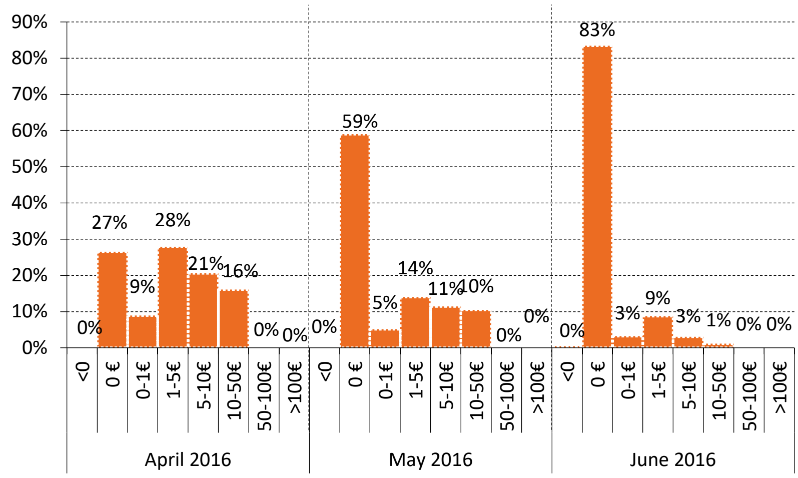
In Germany record February wind production pushed the average spot price down 37% year-on-year reaching low of 22 EUR/MWh while HUPX averaged more than 26 EUR in February. Yet in the first half of March HUPX was cheaper than EEX owing to high supply and mild weather, and for the month the spread was as much as 1 EUR. Forecasts for solar and wind power plants triggered a fall in EEX on 8 May in day-ahead baseload prices to -12.9 EUR/MWh, with peak prices at -36.5 EUR/MWh and hourly prices down to

Figure 8 Comparison of day-ahead baselaod prices on the EEX, OPCOM, OTE and HUPX exchanges between January and June 2016



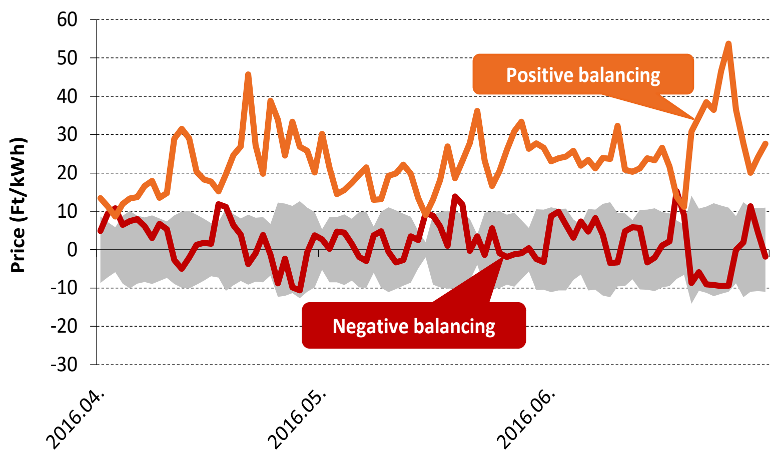
Source: EEX, OPCOM, OTE, HUPX

Figure 9 Frequency of various levels of price difference between the Hungarian and the Czech exchanges between April and June 2016



Source: REKK calculation based on OTE data

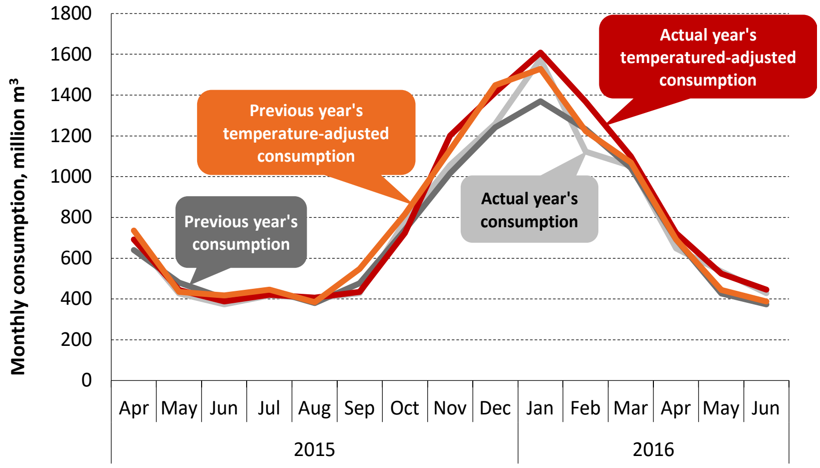
Figure 10 Daily average of balancing prices and spot HUPX prices, Q2 2016



Source: MAVIR, HUPX

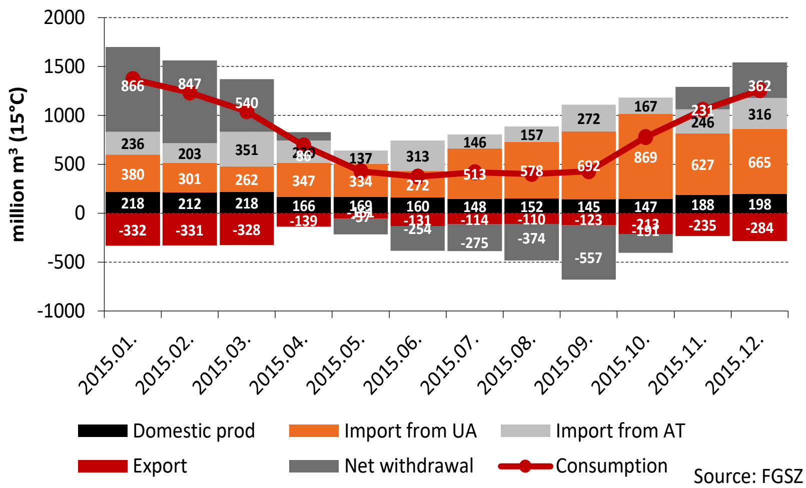
Note: The upper edge of the grey range in the figure is determined by the next day price of HUPX, while the lower edge is the opposite of the same price. According to the Trading Rules of MAVIR the price of positive balancing power is limited to the next day price on HUPX, while the negative balancing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

Figure 11 Raw and temperature-adjusted monthly gas consumption between April 2015 and June 2016 compared with the previous year



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

Figure 12 Source structure of Hungarian gas market by month between January 2015 and June 2016



Source: FGSZ

under -100 EUR/MWh. This day HUPX baseload prices were 32 EUR above EEX (accounting for 19.3 EUR/MWh). The rise in the HUPX day-ahead price and the HUPX/EEX spread in June are attributable to the scheduled maintenance of Block 1 of Paks and the capacity reduction of Block 4 . The June average spot price approached 33 EUR/MW compared 25 EUR/MWh in March.

While yearly baseload HUPX prices were 10-12 EUR/MWh higher than in Germany and Czech Republic, the spreads disappeared in certain months on the day-ahead markets. The alignment of the Hungarian and the Czech day-ahead markets was the strongest in June in the second quarter, with no difference in 83% of the hours compared with 59% in May and 27% in April (Figure 9). In April, the difference between Hungarian and Slovakian prices was less than 1 EUR in less than 50% of the hours and more than 10 EUR in over 10% of the hours. In June the difference was less than 1 EUR on 88% of the hours. The Hungarian-Romanian relationship was the reverse, similar to year-ahead baseload products (Figure 7), with the highest spread in June. While there was no difference between HUPX and Romanian prices in 91% of the hours in April, this fell to 69% in June.

The wholesale price is affected by the costs incurred from the deviation of energy prices from normal scheduling 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 sequence for using the capacities is established according to the energy tariffs offered on the day-ahead regulated market. The system charges for balancing developed by MAVIR provides incentives for market participants to manage anticipated deficits and surpluses through exchange based transactions. For this purpose, the price of upward balancing cannot be lower than the HUPX price for the same period, while the system operator does not pay more for downward balancing than the price at the exchange. In the second quarter, the average price of positive balancing was 23 HUF/kWh more than the average of the second quarter of 2015. The peak of 54 HUF on 25 June can be explained by the 100 MW capacity limit placed on Block 4 of Paks owing to an automatic protection operation (Figure 10).

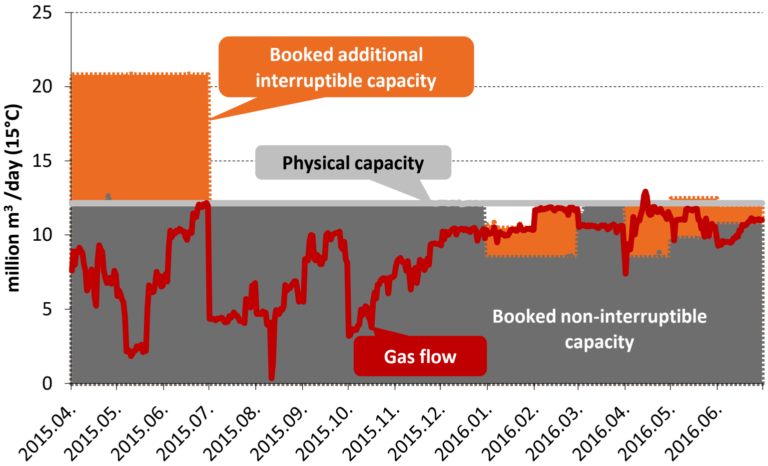
Overview of domestic gas market

The first half of gas consumption in 2016 was 5.4 bcm, 300 mcm more than the same period last year. This is mostly attributable to a colder than average January in which consumption grew by 200 mcm year-on-year. Temperature adjusted data show an even bigger growth in consumption amounting to the equivalent of 400 mcm (Figure 11) resulting from a mild February.

Domestic production in the first half matched the period in 2015 at 1.1 bcm (Figure 12). Cheaper oil-linked gas prices led to a significant rise in imports from the Ukraine border, jumping from 1.9 to 2.7 bcm, and a considerable rise over the Austrian-Hungarian interconnector (Figure 13) presumed to be within the framework of oil-linked agreements. This is substantiated by the upswing in Ukrainian-Slovakian flows in May, with 3.6 bcm leaving Slovakia for Baumgarten after 2.8 bcm in April.

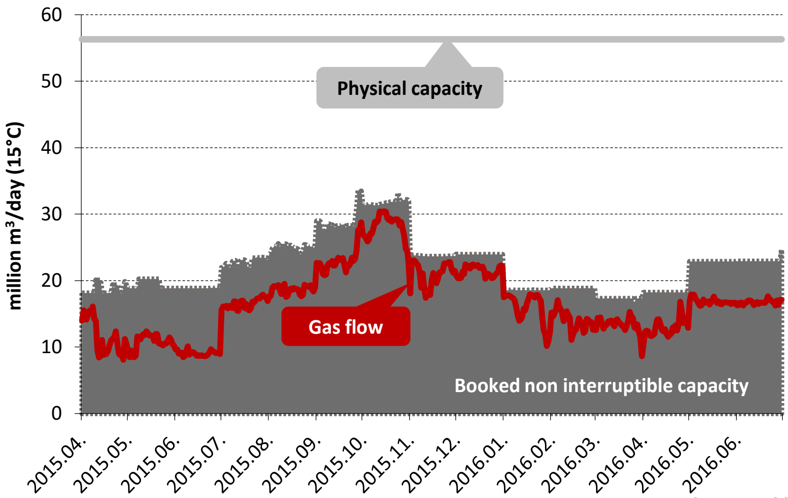
From the first to second quarter of the 2016 the amount of gas transported across the Czech-Slovakian inter-connection was up by nearly 80% as more Russian gas was transported to Baumgarten via Nord Stream. This is further verified by the Slovakian TSO Eustream in its pronouncement that Gazprom was committed to using both the Slovakian and the Czech transmission network even with the construction of Nord Stream 2. Russian gas can also reach Poland on the Czech-Slovakian route, which would be punctuated by the new Polish-Slovakian pipeline that is expected to be completed by 2021 following an open season procedure launched in the summer. It is designed to transport 5.7 bcm/yr to Poland and 4.7 bcm/yr to Slovakia.

Figure 13 Transmission at the Mosonmagyaróvár (Austrian border) entry point between April 2015 and June 2016 together with booked interruptible and non-interruptible capacities



Source: FGSZ

Figure 14 Transmission at the Beregdaróc (Ukrainian border) entry point between April 2015 and June 2016, together with booked interruptible and non-interruptible capacities



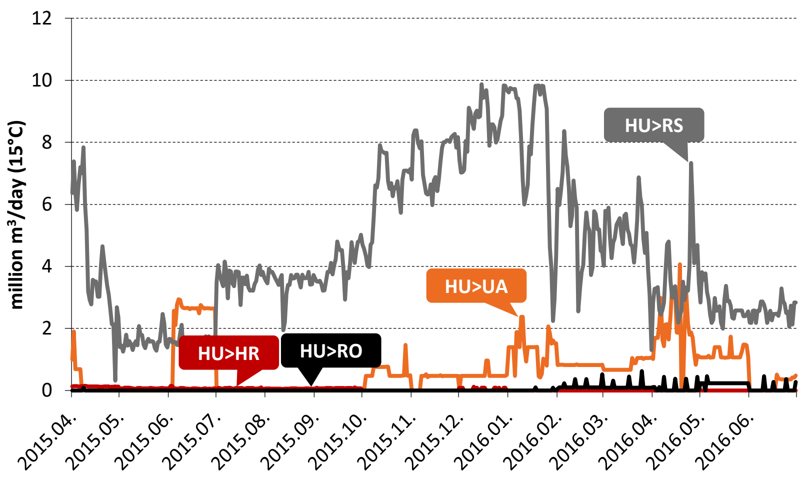
Source: FGSZ

While net injection in the second quarter of last year was only 330 mcm it rose to 930 mcm in the second quarter of this year. The growth is explained by injections already underway in a milder April and changes in regulation. Now the universal service providers must inject into storage 60% of the highest household winter demand of the past 10 years, whereas in the previous period 60% of the expected winter demand had to be injected into storage by 15 October. Despite this change, GIE data shows that domestic storages levels were only at 24% by the end of June compared to 27% in 2015. The is primarily because the starting storage reserve level was 21% last year and less than 17% this year.

As Figure 13 depicts, the interconnection capacity utilization of the Mosonmagyaróvár entry point was high in the course of the half year generally exceeding 80% but sometimes even reaching 100%. Declining oil-linked gas prices led to a significant fall in imports from Austria beginning last April with interconnection capacity utilization accounting for 62% in the second quarter of 2015, while it averaged nearly 90% in the April-June period this year. In the first quarter of 2016 the utilization of Beregdaróc entry point rose modestly from 25% to 28% year-on year, and the two quarter average of 26% moderately lags behind the 29% in 2014 (in the first half of 2015 the interconnector operated at a very low utilization rate of 19% owing to the Russia-Ukraine conflict). Traders have not contracted interruptible capacity on the Hungarian-Ukrainian border since last January (Figure 14) following the modification of the Hungarian Gas Act that entered into force in April 2015, which stipulates that the transmission system operator can offer interruptible capacity only if non-interruptible capacities on the given entry-exit point have been contracted to the extent defined in the Degree of the president of Hungarian Energy and Public Utility Regulatory Authority (MEKH).

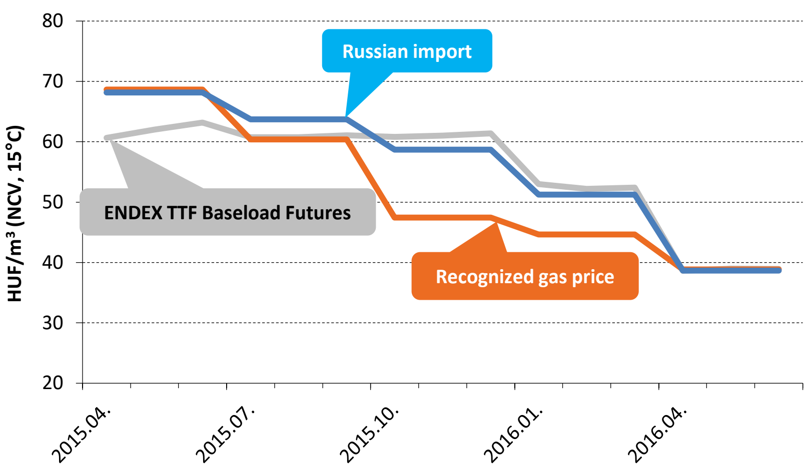
Hungarian gas exports accounted for 1 bcm in the first half of 2016 accounting, a 300 mcm drop year-on-year. Exports to Serbia continued to represent the strongest share with 78% compared to 65% in the same period of the previous year. The rise in Serbian exports was offset by shrinking Ukrainian exports, falling from 29% to 20% (410 to 190 mcm respectively) as seen in Figure 15. Nonetheless, at the end of May Ukraine requested a tender to purchase European gas, which might lead to greater Hungarian exports to Ukraine in the second half of 2016. The Hungarian Natural Gas Transmission

Figure 15 Hungary's natural gas exports to Ukraine, Croatia, Romania and Serbia from April 2015to June 2016



Source: FGSZ

Figure 16 Recognised natural gas selling price of universal service providers and elements of the gas price formula between April 2015 and June 2016



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.

Company FGSZ Ltd launched a voluntary survey among market players in May to determine long term demand and gauge the need for an extension of interconnection capacities. Currently, only non-interruptible capacities totaling 16.8 mcm/day are available to transport gas to Ukraine.

REKK found that there was no significant difference in the second quarter between the recognized purchase costs of universal service providers (defined in a gas price formula included in the relevant decree) and the effective prices of imports from Russia calculated on the basis of Eurostat data (Figure 16). This is primarily due exchange rate fluctuations since the April decree (HUF/USD: 280; HUF/EUR: 310), allowing for a better reflection of market prices and real costs. Since last July, Russian import and TTF prices have not been separated by more than 3 HUF/cm when converted into HUF at a market exchange rate and calculated with the gas price formula, i.e. as the average of prices between the 1st and the 15th day of the second month of the quarter preceding the actual quarter. Russian import prices fell by more than 40% on a yearly basis by June to 12.27EUR/MWh, less than the TTF monthly average price (14.42 EUR/MWh) and slightly lower than German border prices (12.36 EUR/MWh).

The REKK Foundation for Cooperation in Regional Energy and Infrastructure Policy (REKK Foundation) was established in 2016

Today the global transformation of energy systems poses a greater challenge than ever for decision makers, challenges that require a strategic response. This is why, building on the results achieved in education and research, the REKK Foundation for Cooperation in Regional Energy and Infrastructure Policy was established in 2016.

The Foundation aims to contribute to the creation of financially and environmentally sustainable systems of energy and infrastructure in Central Europe. The activities of the Foundation will yield discussion papers and proposals that articulate forward-looking answers to the current questions related to the operation of energy and infrastructure systems. At the regional and Hungarian events of the Foundation, the participants will have a chance to learn about the recent technological and regulatory developments of the sector.

The REKK Foundation aims to achieve the above goals primarily through the activities listed below:

- Creation of an open, professional forum to learn about and discuss the domestic, European, regional and international aspirations of energy policy.
- Enhancing the knowledge base on the regulation of energy markets and other network utilities as well as the market mechanisms of these sectors, researching and teaching the applied practices.

In 2016 a number of important topics have already been discussed across Foundation events. Jos Delbeke, the climate policy Director-General of the European Commission, was the keynote speaker at the first Central and South-East Europe Energy Policy Forum, who, together with the ministry representatives of seven European countries, led a discussion focusing on the sharing of the EU's 2030 renewable targets among member states.

As part of the REKK Market Monitoring Club series, the following topics were discussed:

- The pricing alternatives of the electricity and gas universal services in Hungary
- The future of the Slovakian-Hungarian gas interconnector
- The room for integrating renewables into the domestic electricity system
- The framework regulation for the utilisation of ground water resources

The current and future events of the Foundation are available at

rekk.org

Trends in European coal to gas fuel switching and a Hungarian case study

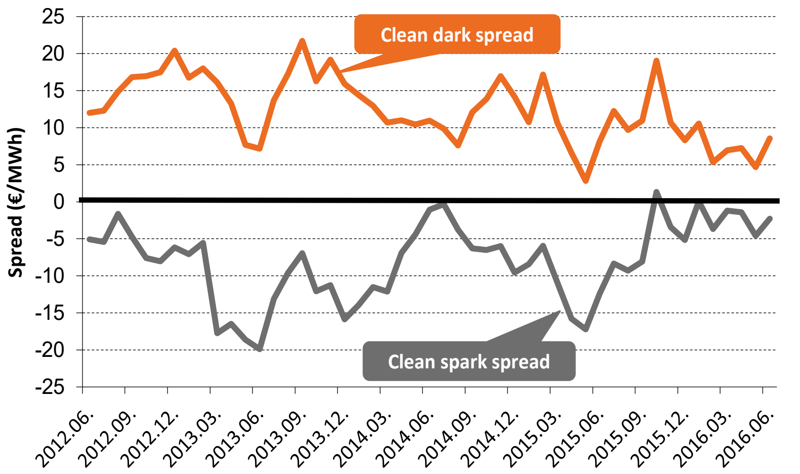
Even as electricity demand remains largely stagnant across Europe, the use of natural gas in Europe's power generation mix is showing prospects for growth, albeit not uniformly. In the overall picture, lower gas prices, retiring coal plants, the need to reach environmental goals, and the planned phase out of nuclear energy should in theory help natural gas rebound. Europe's Large Combustible Plant Directive (LCPD) together with individual policies in Western Europe that aim to phase out coal and nuclear capacity will relieve some of the pressure on CCGT generation. At the same time, Central and South Eastern Europe (CSEE) is comfortable with coal and nuclear retaining prominent roles in the generation mix, with a majority of Europe's planned coal new build driven by Poland. Britain's unilateral carbon price floor and some of the lowest NBP prices in the last decade continue to push coal generation down the merit order curve and into the red. Across continental Europe natural gas is also becoming more price competitive with coal as an input, evidenced by trends in clean and dark spark spreads, but the low ETS price has failed create an overwhelming sentiment for industry-wide switching. While depressed gas prices are beginning to create small windows for the profitable use of natural gas in power generation, more aggressive unilateral policy action akin to the British and French carbon floors will need to be taken up in Belgium, the Netherlands and most importantly Germany for gas to make a significant breakthrough.

The broad decline of gas consumption in Europe in past years, down 23% in 2014 from its 2010 peak-level (2014 consumption was equal to that of 1995), resulted from a perfect storm of demand and supply-side factors: falling electricity consumption due to low economic growth, rapid penetration of zero marginal cost renewable energy sources and the availability of cheap coal buoyed by an ineffectively low EU carbon price. All of this while contracted gas tracked persistently high oil prices and the shock of Japan's Fukushima disaster tightened the global LNG market, rendering even the highest efficiency CCGT plants in Europe uneconomical to operate.

Over the past year, however, the clean spark spread has begun to improve, paving the way for more widespread fuel-switching opportunities in Europe in 2017 and beyond This has been predominately driven by extremely low hub prices in 2016 that are expected to continue. The wholesale price of natural gas began to fall in 2013 as contractual pricing and volume adjustments between Gazprom and its largest customers began to take effect. Demand fell precipitously from 2013 to 2014, bringing down not only spot prices but also the LTC prices that now had more exposure to the spot price. Then at the end of 2015 the lagged effect of the collapse in oil price began to transmit through long term contract volumes, further lowering the German border price and bringing them closer to hub price convergence. Now in 2016 a significant shift in global LNG markets is underway that will exert more downward pressure on European prices. Some 100 bcm of LNG from Australia and the US will enter the market in the next 2-3 years just as demand in Korea and Japan - the largest LNG importers in the world - is slowing for the first time, making Europe the destination of last resort. Thus natural gas prices are expected to remain soft in the medium term due to inelastic LNG supply and tempered European demand-side response, a result of weak power generation growth, the continued roll-out of renewables, and rock-bottom coal prices. As the IEA 2016 natural gas medium term outlook notes, natural gas markets are unlikely to rebalance before the end of the decade.

Lower natural gas prices have improved clean spark spreads across Europe, with the baseline figure in Germany shifting from a low of -15 euro/MWh in June 2015 to a band between -5 and 0 MWh in the beginning of 2016 as depicted in Figure 1.

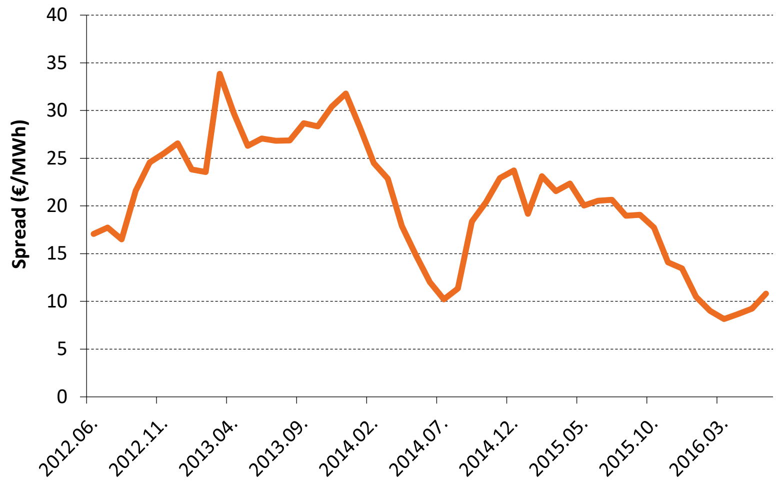
Figure 1 Evolution of average European clean dark spread and clean spark spread between 2012 and 2016



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

For a brief period in mid-August German clean spark spreads exceeded clean dark spreads for the first time since 2011, but still future clean dark spreads continue to favor coal over natural gas and offer little incentive for switching. A similar dynamic is playing out in the Netherlands, as month-ahead spreads in August reached their highest levels since 2011, mostly attributable to the TTF month-ahead price which fell to its lowest level since 2009. Comparatively, in Italy the 2015 clean dark spark spread averaged 0, up from -10 euro/MWh in 2014.

Figure 2 Difference between average European clean dark spread and clean spark spread between 2012 and 2016



Although the difference between the clean dark and clean spark spread has been broadly decreasing since late 2015 (Figure 2) driven by low gas prices, in countries without additional policy intervention coal fired plants are still 'in the money' while gas fired plants are only approaching breakeven levels with temporary incursions into profitability. In countries like Germany or Poland, where coal plants dominate the wholesale price setting of the power market, switching will be limited with the European carbon price hovering around 5 euro/tonne.

This equation, however, is completely different in the UK which became the first member state to institute a carbon price floor in 2013. Consequently coal plant margins have been declining since the beginning of 2014 while natural gas has taken a more prominent foothold in the generation portfolio. Through the first quarter of 2016 a total of 7.6 bcm was used by gas-fired power stations, marking a 50% increase year on year in gas-for-power demand. In the second quarter of 2016, half (50.9%) of UK power production came from gas with coal accounting for only 6.8%, its lowest ever percentage.

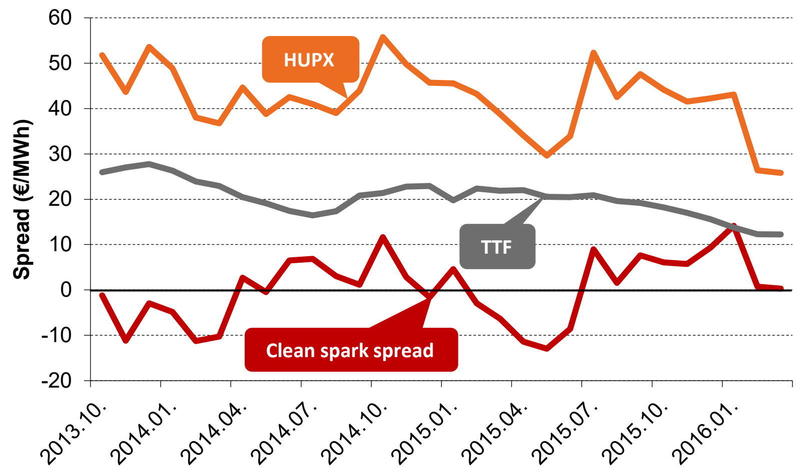
The government doubled the tax in April 2015 to achieve a price level of £18 per tonne, and in December 2015 the average clean dark spread was -£1.7 MWh, Britain's first negative such spread on record for a complete month, and it has remained negative in 2016. The policy initiative has destroyed Britain's coal fleet, with more than a third of capacity closed in the space of a month, April, during which coal generation more than halved. Overall, 5 of 11 remaining coal plants were closed and 8 GW of the remaining 18 GW will close in 2016 unless there is an intervention by National Grid.

France is poised to impose a similar unilateral price floor, targeted at 20-30 euro/tonne. However, in France the impact on emissions and wholesale power prices will be far more limited since the power sector depends on fossil fuels for only 10% of generation to begin with.

For the rest of Europe, downward pressure on gas prices from 2017 is expected to continue improve the clean spark spread. LNG, and particularly US LNG underwritten by a low US Henry Hub price in the band of $3-4 mmbtu, will increasingly act as an implicit price buffer, reinforcing downward pricing pressure. The price of coal bottomed out at its zero cost price range of 40-45 euro/tonne in 2015 but it has recovered to a degree in 2016 due to Chinese market dynamics.

While there are signs of life for existing gas fired plants resulting from improved spark spreads and load factors, there is still little overall appetite for investment in any type of new-build thermal, even in the UK. The prevailing energy policy in Western Europe favoring renewable energy sources over fossil fuels has led directly to the current environment of low wholesale electricity prices, eroding margins of existing thermal plants and creating little prospect for new power plants to recover future operating costs. Ten of the largest European utilities mothballed 21.3 GW of gas fired stations in 2013 due to the altered market conditions. According to the 15th European Energy Market Observatory report, 130 GW of gas plants across Europe (about 60%) are not recovering fixed costs and are at risk of closure in 2016. In 2014 thermal new build in Western Europe reached an all-time low, with less than 4 GW of CCGT and 7 GW of coal under construction according to Platts Power in Europe plant tracker. Furthermore, in 2015 CCGT and coal new-build totaled only 7 GW. It follows that UK thermal expansion has proven to be almost entirely dependent on a capacity mechanism auction introduced in 2015 for 2018/19 delivery,

Figure 3 Monthly average Hungarian electricity prices, TTF gas prices and average Hungarian clean spark spread



Source: HUPX, Gaspool, EEX

guaranteeing 15-year support. Without the additional support, the projects are not profitable. Meanwhile, three times as much coal plant capacity is being built in CSEE than Western Europe, highlighting the divergence in energy policy, asset age and replacement capacity needs across the EU.

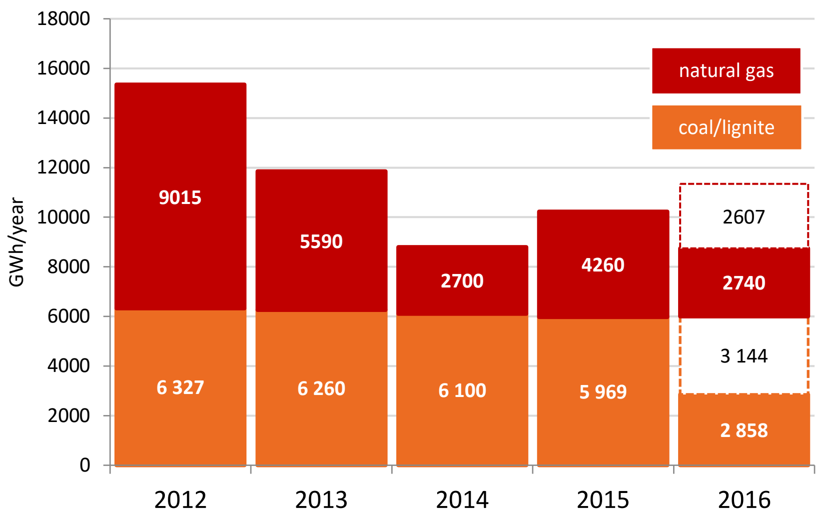
Case Study: evolution of Hungarian natural gas based electricity production

In the last few years important changes took place with respect to the Hungarian natural gas based power production. After years of declining production and low capacity factors gas fired power production is on the rise again. Gas based generation declined steeply from 9 TWh in 2012 to 2,7 TWh in 2014, then bouncing back up to over 5 TWh in 2016. As shown in Figure 1, the favourable changes in the international gas markets (decreasing gas prices thanks to lower oil prices and higher LNG supply) clearly effected the Hungarian market, and in the past two years average clean spark spread (shows how profitable is to produce electricity from gas) reached positive territory several times.

This development is clearly visible in the Hungarian electricity mix as well. The share of nuclear and coal/lignite based production was quite stable from 2012 to 2015 (36-38% and 15-16% respectively), while the share of natural gas based electricity production went down from 21% (2012) to 7-8% 2014-2015) and the share of imported electricity increased from 20% to 34%. Now this trend seems to have reversed, as the share of imported electricity in the first half of 2016 declined to 30% and share of gas based production went up to 10%. It will be shown later that, compared to the same period of 2015, this was a sizable increase in gas based production.

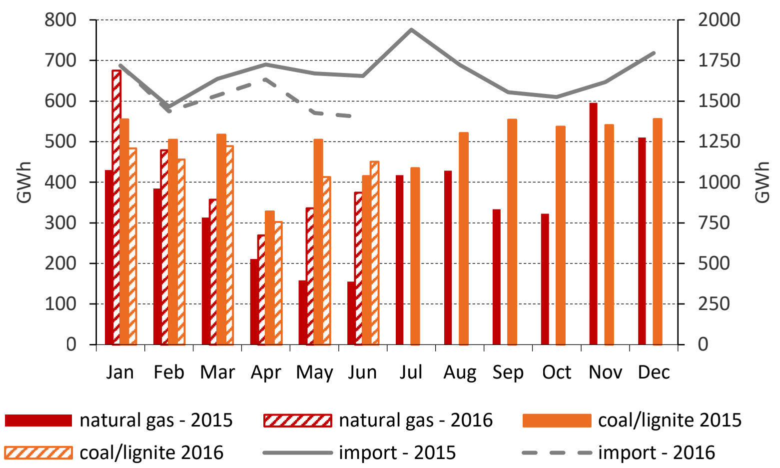
It is important to explain how the different profiles of natural gas based power production in Hungary categorize their behaviour. Some are "free to decide" their production level, only taking into account the prices of gas and electricity, while others are influenced by several other factors (price of ancillary services, balancing services and heat). The domestic natural gas based power producers can be categorized into three main groups: first CHP plants, where the main driver of production is heat demand in the heating season and ancillary services in the non-heating season (e.g. Budapest Erőmű); second the key players of the tertiary market, only used if the TSO calls upon them (e.g. Litér, Lőrinci, Sajószöged); and third dispatchable power plants, which determine their generation based on opportunities in the power and ancillary markets and balancing services (e.g. Gönyű, Dunamenti, and the so-called virtual power plants). Another driving factor can be a long-term contract that forces the producer to generate electricity even under unfavourable market conditions (e.g. Csepel), however in these cases producers usually receive "individual" prices that make electricity market conditions irrelevant. On one hand all of these factors can provide an explanation for the 3 TWh of yearly natural gas based power production, even during times of negative clean spark spread. On the other hand the calculated spread is an average, thus the real spread that the power plants face can be different for each type of producer according varying efficiency levels, individual gas procurement contracts, ancillary/-balancing service fees, heat market incomes, etc.

Figure 4 Natural gas based and coal/lignite based electricity production in Hungary, 2012-2016



With the recent spike in natural gas based power production, the question becomes what is it displacing? In order to assess this, we obtained monthly production data from the beginning of 2015. Since demand remained more or less unchanged (from 2012 to 2015 only a 5% increase), increasing natural gas based production necessarily took the place of other sources of electricity. Renewable (associated with the FiT system) and nuclear production are independent of the level of natural gas based production, thus only coal/lignite based production and imports were included in the following figure.

Figure 5 Monthly natural gas based and coal/lignite based electricity production and the level of import in Hungary, 2015 January – 2016 June



In the first 6 months of 2016 both coal/lignite based power generation and electricity imports decreased compared to the first half of 2015, however the latter was more significant. Coal/lignite based production declined by 30-90 GWh/month (and even increased a bit year on year in June), while by the end of the semester imported electricity decreased by more than 250 GWh/month year on year. In this first half of 2016, gas based production was more than 800 GWh higher than the first half of 2015. Thus for the most part, natural gas crowded out imports rather than coal/lignite based production. This is not a surprise, as the biggest lignite based producer, Mátra, has its own lignite resources, thus gas based production can hardly compete with it in the electricity market.

Finally we had a closer look at the market participants to see which power plants spiked in production growth over the past few years. The most important market players are included in the following table, with the grey background representing natural gas based power producers. For 2016, data until the end of June was available.

The load factor of Paks (nuclear) and Mátra (lignite) power plants remained more or less the same over the whole period, while the slight decrease in the Hungarian coal/lignite based power production is visible for Vértes power plant (this CHP plant also applies biomass co-firing). The production of the three units of the Budapesti Erőmű (Kelenföld, Kispest, Újpest) remained roughly flat with a slight increase – as mentioned earlier, these are CHP units also producing district heating - while the generation of Csepel declined significantly . After a change of ownership and a year with almost zero generation Dunamenti power plant started to produce electricity again from 2015, and the trend continued in the first half of 2016 too. The most dynamic increase is observable at the Gönyű power plant. For the virtual power plants (mostly small gas engines) the load factor should be taken into account together with the total installed capacity, making it clear that the highest production level was reached in 2015, and generation remained high in the first half of 2016.

We can see that the Hungarian natural gas based power production trended up in the last year plus. This electricity mainly crowded out imports, but coal/lignite based production also decreased slightly. Favourable changes for natural gas based power plants induced similar developments at the European level and, as referenced in the first section of this report. The continued competitiveness of natural gas will be dependent on low market prices and the evolution of the European carbon price through the ETS and unilateral country-level actions.

Table 1 Utilization of some major power stations in Hungary, 2013-2016

	Paks	Mátra	Budapesti Erőmű	Vértes	Gönyű	Csepel	Dunamenti	Virtual Power Plants	
2013	88%	74%	27%	42%	6%	25%	10%	30%	390 MW
2014	89%	74%	26%	34%	18%	12%	1%	21%	430 MW
2015	90%	72%	29%	27%	26%	13%	8%	22%	560 MW
2016*	97%	66%	33%	15%	29%	15%	15%	21%	563 MW

Implications of carbon price floor: Coal remains below…

In May, French Minister of Ecology, Sustainable Development and Energy Segolene Royal announced her intention to implement a domestic carbon price floor for the French power sector from the beginning of next year. The measure seems to be modelled after the "top-up" carbon tax in the UK. It would ensure that French power producers pay a minimum carbon price of €30/tCO_2 – according to currently available information – by charging a tax on fossil fuels used for power generation. The new policy would tax fuels at a level that bridges the difference between the price floor and the carbon price generated by the EU ETS (EUA).

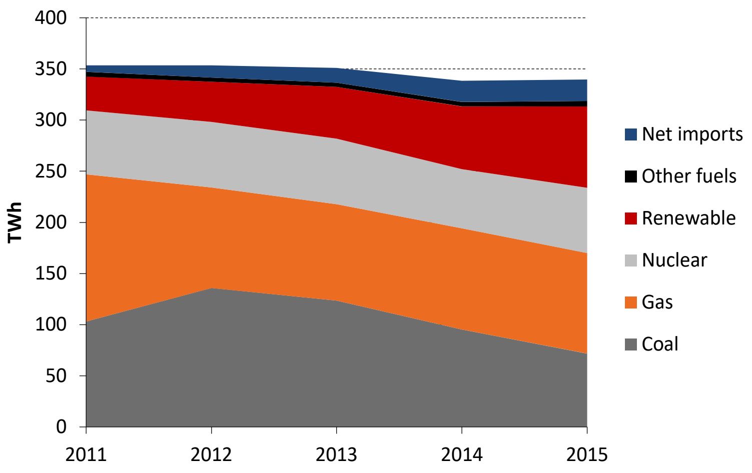
Mechanisms established to reform the EU ETS such as backloading 900 million EUA and the Market Stability Reserve (MSR) set to launch in 2019 seem to fall short. EU lawmakers expected temporary supply cutting measures to affect market players' short-term (3-5 years) thinking and increase allowance prices. However, as experts have pointed out, the approximately 2 million tons of surplus accumulated will maintain in oversupply on the market until the end of the 2020s. Furthermore, market players have incorporated reforms into their strategy and current EUA prices are still lower than 5EUR.[1] The reason that EUA prices did not fall to zero is because market players are 'long-sighted' rather than 'short-sighted', already pricing the reduced future supply of EUAs, which can be used for an unlimited time period.

In February, France introduced its proposal for a carbon price corridor aiming to raise the current carbon price from current levels and encourage low carbon investments. The potential price corridor could be set up similarly to the supply control mechanism used in the Market Stability Reserve by changing the currently applied surplus-based reserve mechanism to a price-based one. If an auction cleared below the price floor no allowances would be sold, but rather stored for later in the MSR, or the auctioned quantities would be limited until the price exceeds the price floor. If prices peaked over the price ceiling, the auctioned quantity would be increased. The price corridor would be set by increasing floor and ceiling prices from 10-25EUR and 30-50EUR respectively.[2] This concept has been submitted as a package of amendments to the legislation for the review of the EU ETS directive.

The French government wishes to lead by example and adopt the domestic carbon price floor at the beginning of 2017. Ms. Royal's team proposes the introduction of not a single carbon price floor but a regulation governing only the most polluting power plants based on technical standards, possibly applying an increasing carbon tax.[3] This would focus on coal-fired power plants by applying discriminative measures largely exempting flexible gas-fired power plants from this tax.

In the UK, the Carbon Price Floor (CPF) has been in force since 1 April 2013. In the framework of CPF, electricity producers pay a tax, the Carbon Price Support (CPS), in addition to the EUA price equivalent to their annual production. The tax is preset for a 3-year term based on the actual allowance price in order to provide a degree of certainty for producers and investors. The initial tax set at 4.94 GBP/tCO_2 grew to 9.55 GBP/tCO_2 from April 2014, then to 18.08 GBP/tCO_2 from 2015. For the 2016-2020 period the price was fixed at 18 GBP/tCO_2 instead of following the very ambitious growth plan, whereby it was set to grow to 30 by 2020 and 70 GBP/t by 2030. It now costs approximately 28 EUR to emit 1 ton of CO_2 (calculating with 4.7 EUR/t EUA price and 1.17 EUR/GBP exchange rate). The first figure shows electricity consumption according to fuel types in the United Kingdom since 2011.

Figure 1 Structure of electricity consumption according to fuel types in the United Kingdom, 2011-2015



1 SWD(2014) 17 final

2 Non Paper – A soft price collar for the European carbon market, http://carbon-pulse.com/16939/

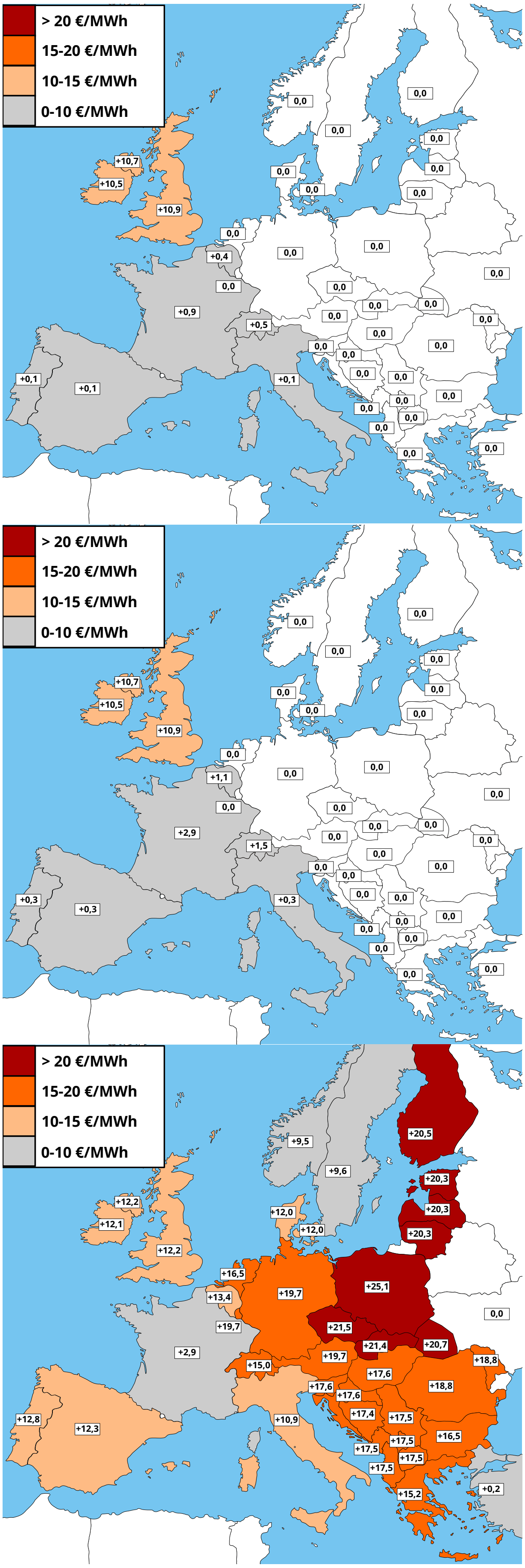
3 Platts, Power in Europe, Issue 730, July 18, 2016, p.3.

The figure depicts the phase out of coal-based production since the introduction of carbon price floor; its share of 38.4% in 2012 dropped to 21.1% by 2015. The continuously increasing carbon floor price has a crucial role in the gradual fall in coal-based electricity production, however, last years' drop in gas prices and cuts in emission limit values also influenced the trend.[4] The transformation in electricity production is also evident by temporary or final shutdown of several old coal-fired power plants. In March-April 2016, capacity totaling 5 GW was phased out[5] including Ferrybridge C in West-Yorkshire, which went through renovation extending its lifespan by 7 years, and Longannet, the last Scottish coal-fired power plant, which was about to make a CCS investment backed by state aid at the beginning of the decade.[6] The British government expects a total phase-out of coal-based electricity production by 2025 due to the carbon floor price.

The most important impact of the French carbon floor price would be to drive coal out of the generation mix, experts say. This change, however, would not come as a shock to the French electricity system with only 1.6% of power production coming from coal-fired power plants, 0.5% from oil-fired, and 4% from gas-fired in 2015. Electricity production in France is dominated by nuclear and renewables, which accounted for 76 % and 18% of total generation in 2015 respectively. Thomson Reuters forecasts a 3 EUR rise in French power prices and 6 million tons reduction in CO_2 emission as a result of the measures. This amount is equivalent to the annual output of Mátra Power Plant. Cynics believe that the reason behind the introduction of carbon floor price is to save the French electricity industry incumbent EDF and its fleet of nuclear power plants. EDF is suffering from a weak financial position, and the French government, the majority stakeholder, must provide assistance in the form of taxpayer revenues.

As for the European carbon price corridor proposal, debates and discussions among member state representatives so far suggest that there is not enough support for such a measure to gain a qualified majority of support from EU representatives. Nevertheless, a German draft regulation leaked in May does suggest that Germany may back the proposal which would significantly improve its chances. Reforms would be finalized in the first quarter of 2017 at earliest with the measures implemented after 2020.

Figure 2 Price effect of 30 €/t carbon price floor on wholesale electricity prices; €/MWh
Top: Carbon floor price is introduced only in the UK;
Middle: Carbon floor price is introduced in the UK and in France;
Bottom: Carbon price floor is introduced in each country



4 *Emission limit values to large conbustion plants are set by Directive 2001/80/EK (LPC) and the replacing Directive 2010/75/EU (IED).*

5 *Platts, power in Europe, Issue 725/May 9, 2016: UK coal-fired output halves, pp 1,2.*

6 *The project was cancelled in 2011 due to high costs. Source: PIE, issue 612, Oct 31, 2011*

What if...

The European Power Market Model developed by REKK is able to provide in-depth analysis on the effect of member state-level carbon floor prices on wholesale power markets. To evaluate the potential market effects, three scenarios are compared to a reference case without a carbon floor price, which are the following:

- 30 €/t carbon floor price is introduced only in the UK.
- 30 €/t carbon floor price introduced in the UK and in France
- 30 €/t carbon floor price is introduced in each ETS country.

The following figure shows the rise in electricity prices in 2017 in the various scenarios.

If a carbon price floor is introduced only in the UK, the effect is focused in the UK and Ireland with France, Belgium, Switzerland and Spain slightly effected due to electricity market coupling. The UK price increase will be very significant, exceeding 10 €/MWh and equivalent to a 30% rise in wholesale prices while on the continent the price is rise is less than 1 €/MWh in nearby countries.

If, in addition to the UK, France also introduces a 30 €/t carbon price floor, it would not affect continental electricity markets significantly. France would experience a 2 €/MWh (6%) increase in wholesale prices owing to the low share of coal-fired capacities (below 5 %). It would be slightly detrimental to Swiss, Belgian, Italian and Spanish customers, where wholesale electricity prices rise marginally by 0.3-1.5 €/MWh.

Alternatively, European customers would face a dramatic price increase if a 30 €/t carbon price floor was introduced in each country. The effect would be the most drastic in Poland and Czech Republic (with 25.1 €/MWh and 21.5 €/MWh price increase, respectively) where electricity production is mainly based on coal, but it would also carry over to neighbouring countries. The price increase would be over 17 €/MWh in Hungary, accounting for a 50% increase from current futures prices that are in the range of 30-36 €/MWh.

The measure would hardly have any effect on Nordic countries rich in hydro generation or Spain and Italy that have a large share of gas in their generation mix.

In addition to the effect on wholesale electricity prices, we also examined its effect on CO_2 emissions of the generation sector and on allowance revenues, the results of which are depicted in the below table. Allowance revenues come from auction, and can be used by the given Member States under predefined conditions.

The carbon price floor introduced in the UK significantly reduces its CO_2 emission, amounting to close to 100 million tons. This represents 5% of the total emissions of the European ETS sector. At the same time, the other modelled countries see an increase, particularly in Ireland. In addition to decreasing CO_2 emissions, the UK would see a considerable - nearly 1 billion EUR - rise in its revenues coming from EUA sales owing to higher allowance prices.

The French carbon price floor, however, would have a substantially minimal effect, as was demonstrated through wholesale prices. Although CO_2 emission would significantly fall in France, the drop in Europe would be less than 4 million tons accounting for 0.5% of the total emissions of the European ETS sector. French EUA revenues would also go up, but by less than 60 million EUR annually.

A carbon price floor amounting to 30€/t introduced in each member country would be able to significantly reduce the European ETS sector's emission by 15-20%, while annual EUA revenues would grow by 12.8 billion EUR in Europe.

The analysis shows that the British carbon price floor has very significant effects on England and Ireland in particular, but also some moderate impacts on the continent. However, the French measure would not result in any drastic change either on the European or the French power market.

Table 1 Effect of carbon price floor on CO_2 emission (mt) and allowance revenues (m€)

	Change in CO_2 emission, mt			Change in allowance revenues, m€		
	UK	UK and France	Each country	UK	UK and France	Each country
United Kingdom	-91.5	-91.1	-73.8	926.6	936.1	1 455.5
France	1.4	-10.0	2.8	7.4	64.8	448.5
Each country	-76.1	-80.0	-369.0	1 010.6	1 116.3	12 818.2

REKK Renewable Energy Week - conference summary and evaluation

On 7-9 June, REKK organised a conference focusing on four current themes within the regulation of renewable based electricity generation: the questions surrounding the achievement of the 2030 EU targets, regional progress with respect to the 2020 renewable targets, the plans on tender procedures to be applied in the near future, and the framework rules pertaining to the new new renewable energy support system (METAR) soon to be introduced.

The first day of the conference focused on the important elements surrounding the EU 2030 renewable target of 27% as depicted in the Towards2030Dialoge project.[1] Namely, the question of how the achievement of the common EU level renewable target could be incentivised without adopting obligatory national targets. The common target implies the complete abandonment of the currently applied method (such as the national targets set by the European Commission), therefore the development of appropriate instruments poses a substantial challenge to regulators on the level of both the EU and the member states. Since the 2030 framework does not assure the fulfilment of the target, not even on the level of pledges, the EU has to make timely preparations in case the "burden bearing" of member states is not ambitious enough to reach the 27% target.

Day 2 was a review of what the region has so far accomplished towards the 2020 renewable targets. While there are still four years left until the 2020 target date, current trends offer some interesting conclusions with respect to the attainment of both regional and EU targets. Discussion with the ministries of the participating countries shed some light over "good" and "bad" practices within the operation of renewable regulatory and support systems in the region. In the afternoon, the subject was the method and depth to which given member states intend to apply the (to a large extent) obligatory renewable tender procedure that will be launched in 2017. The co-organiser of the event, the AURES project, provided assistance in the introduction of this process.

Day 3 aimed to introduce and discuss the concept of the new renewable support scheme (METÁR) with the participation of the regulatory authority and the representatives of the sector. In addition to analysing the main features of the system, the conference paid special attention to the network integration of weather dependent renewable energy producers and the room for the participation of large corporations.

In sum, the three days of the conference reviewed the most pressing issues of renewable regulation on a wide spatial (EU, CEE region, Hungary) and temporal (2030, 2020 and 2016) horizon; with this article we would like to offer a summary and short evaluation of the event while also providing links to the sources used.

Question marks surrounding the achievement of the EU 2030 targets

On Day 1, the review of the suite of instruments deployed to achieve the 2030 renewable targets of the European Union was intended to answer four questions:

- How can the Commission encourage Member States to set ambitious national renewable targets contributing to the common European target of 27%?
- What are the steps that the Commission needs to take in case the sum of voluntary national targets lags behind the common European goal?
- Is it necessary to set country specific benchmarks in order to determine the national targets? If the answer is yes, what method should be used to establish the benchmarks: uniform percentage increase prescribed for each country, based on GDP per person, based on the renewable potential or a given combination of these methods?
- If the sum of assumed national targets stays below the common European target, then what method can be utilised to "fill the gap"?

In its report the Towards2030-Dialogue project investigated the potential answers to the above questions; the goal of the REKK event was to map how the member states of the region reflect upon the suite of instruments that can be applied.[2] The framework for the workshop was set by the opening presentation of Jos Delbeke, director of the Commission on EU ETS reform and the role of renewables.

1 The October 2014 decision of the European Council (EUCO 169/14) brought into force the 2030 Climate and Energy Policy Framework which includes the 27% renewable target.

2 The following member states were represented at the event: Czech Republic, Lithuania, Hungary, Romania, Slovakia and Slovenia. From Day 2 on a Polish expert also participated.

The participating government representatives shared their distinct opinions on the above questions, often outlining substantially different directions, but in the wake of the discussion a number of conclusions can also be articulated:

- Setting national goals can follow a "top-down" approach in which determining country specific targets would be closely linked to a benchmark "burden sharing" method developed by the Commission. There could be different methods of allocation, based on GDP, the availability of renewable resources or energy consumption (see the analysis of Towards2030; the combination of different methods is also an option). The other "bottom-up" approach entrusts the member states to set their own targets, which is the method that the current common development of 2030 targets exemplifies. The representatives of the Central and Eastern European member states favoured an arrangement under which target setting remains a member state competence, in harmony with the present principle of common target setting, without any intervention by the Commission. In case benchmarks aiding the comparison and evaluation of member state targets are developed, their role should be limited to information supply, contributing to the development of member state targets without imposing obligations.
- Of the possible benchmarks (GDP, resource availability, energy consumption) regional participants would prefer a mixed system in which a weighted blend of the listed indicators would generate the benchmarks, helping the member states in devising their own renewable target for 2030.
- Deciding on the degree to which targets need to be broken down to sectors was also an important matter of discussion. The evolving consensus pointed to the need to provide more autonomy / latitude to member states in these areas, thus the scheme should ensure flexibility for member state decision makers in setting sector specific targets. Considering the particularities of the transport sector, participants could envisage the application of distinct instruments here.
- There was unanimous consensus with respect to setting interim targets: the participants stick to the 2015 Council decision according to which progress needs to be evaluated halfway through the period in 2025 and until then it is not appropriate or desirable to set interim targets. Such a solution may make the task of the Commission notably more difficult, being left without an instrument to check and motivate the progress of member states before 2025.
- One of the cornerstones of reaching the 2030 target may be the development of a set of instruments that would ensure that in case of insufficient commitments - when the sum of member state targets does not reach the 27% share of renewables for the EU as whole - member states can be prompted to develop additional renewable capacities (gap-filling options). Regional participants more or less agreed that the most suitable instrument would be an auction system covering all member states, under which renewable investors could undertake additional projects in order to make up for the missing renewable generation, and this production would be supported with a premium determined through an EU level auction. This system would guarantee the cost-efficient realisation of the common target. It was also raised that individual member states should be able to leave the system since the network of some member states exposes substantial deficiencies, restricting the perceived room for the expansion of renewables.
- An important question concerning this type of European auction system is the source from which the support would be financed. The most preferred alternative is financing from the European ETS scheme, but direct support from the EU budget and cost sharing based on a predetermined benchmark might also been considered.

In sum, the 2030 renewable target strategy of the regional member states represented at the conference is to establish the widest possible playing field when it comes to setting national targets. This preference is revealed by the fact that these countries refuse both the benchmark based method of setting national targets and the adoption of interim targets; they do not wish to accept the intervention of the Commission in any field. This is also reflected by the priority given to the method of financing that prefers the already existing ETS revenues, as well as by the fact that the role of benchmarking is viewed narrowly as an information tool, without using it to derive actual national targets. While this strategy may seem like an intentional delay, it is understandable, since 2020 is likely to be a milestone and depending on the performance of our region in reaching the targets, significant amendments may take place to the rather plastic 2030 system.

At half-time toward the 2020 renewable targets

During the Day 2 discussion a snapshot of the current state of implementation of national renewable targets in the 4 countries of the region emerged: Czech Republic, Slovakia, Romania and Hungary. The four member states have performed well so far, each reaching a renewable share that is proportionate to or in excess of the time that has passed.

At first glance, therefore, the countries of Central and Eastern Europe (CEE) seem to be on the right track to fulfil the targets. The growth of renewable energy use within the National Action Plans, however, has typically been projected on an exponential path, not on a linear line, submitting a larger portion of the growth to the second part of the decade.

A research project has assessed whether 2020 targets can be reached with the policy measures that are currently in place. As the figure below shows, some of the CEE countries (Romania, Bulgaria, Lithuania, Estonia, Croatia) are on the right path. In the Visegrad countries, however, reaching the goals remains rather questionable, and additional measures are needed.

Based on the Renewable Directive, Romania has to reach a 24% renewable share by 2020, 6.2% higher than its 2005 ratio. This figure, however, already exceeded 26% in 2014 and projects to increase further over the next few years. The main engine of growth is the electricity sector, and as such, Romania belongs to the small group of countries that continue to support green electricity generation via the green certificate system. As a result, several thousand MW of wind and solar capacity has been successfully developed in the last few years.

The Czech Republic has made tremendous gains towards its interim targets, but it comes at a high price: between 2009 and 2011 a sizable PV capacity was developed thanks to exceptionally high feed-in tariffs. Initially this was fully financed by electricity consumers, but the burden increased at such a high rate that after some time new measures were introduced. The level of renewable support was capped at 17 €/MWh and the missing revenue - the difference between the prior level of support and the 17 €/MWh threshold - was financed from the central budget, primarily from the sale of carbon-dioxide allowances. Since 2014 the support for the construction of new power plants within the electricity sector has essentially ceased, the government now focuses on the heat sector to promote renewable energy production.

Slovakia also has progressed favourably toward its to interim targets, but still lags a few percentage points behind the 14% prescribed by the Directive and the 2020 target of 15.3% proclaimed by its own National Action Plan: the share of renewable energy use stood at 12.7% in 2014. Similarly to the Czech Republic, PV capacities grew rapidly in Slovakia, with close to 600 MW built within a few years. While the regulatory response has not been as dramatic as that of its neighbour, the surge of capacities also shifted the focus of renewable generation to the heat sector, specifically to biomass. In Slovakia reaching the 10% renewable share within the transport sector may turn out to be a considerable challenge.

The new auction system

The afternoon on Day 2 dealt with an emerging theme, the allocation of the support for renewable capacities through an auction procedure. The 2014 EU competition regulation is meant to ensure that member states allocate new renewable support only through a competitive process, in essence either an auctioned premium or a green certificate system. Some member states had already applied auction schemes to determine the renewable support they provided (e.g. the Netherlands or France), while Germany only started the auction of PV capacities half a year ago, initially as a pilot scheme. So far the German auctions have displayed favourable results,

Figure 1 Achievement of the targets of the 2013 period, and the expected achievement of the 2020 targets with the current set of measures

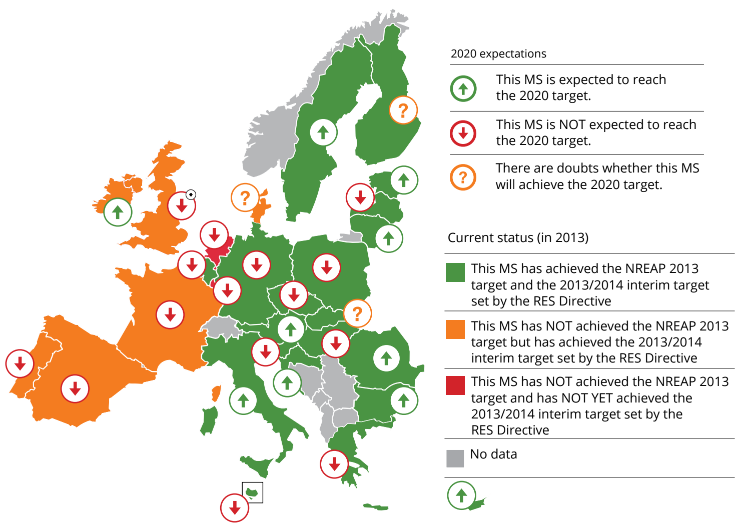


Table 1 Experience with auctions and proposed methods in some European countries

	Poland	Croatia	Germany	Netherlands
Planned first auctions	second half of 2016	n.a.	Since the beginning of 2015	since 2011
Evaluation criteria	Price only	Price only	Price only	Price only
Number of rounds	Single round, sealed bid	Single round, sealed bid	Numerous auctions in a year, but in case of a specific auction single round, sealed bid	Numerous auctions in a year, but in case of a specific auction single round
Discriminatory price/ uniform price	Discriminatory price	Discriminatory price	Depends on the auction	Discriminatory price
Technology neutrality	Five individual auctions for differing groups	Technology diversification	Technologically diversified auctions	Technology neutral
Duration of support	Max. 15 years	12 years	n.a.	n.a.
Annual budget limit	Yes	n.a.	n.a.	Yes
Energy or capacity based	Energy	n.a.	Energy	n.a.
Maximum price	Yes	Yes, technology specific	Yes, in case of wind auctions	Each and every
Conditions of participation	Prior permit; financial guarantee; network access permit; non-fulfilment deposit: 11300€/MW	Construction permit; financial guarantee	In case of wind auctions 30 €/kW of non-fulfilment deposit and almost all permits are necessary	n.a.

with average support in the fifth auction at 7.23 euro cent/kWh, and an oversubscription of the offered capacity of 125 MW by almost three times. The German subsidy is significantly below Hungary's current feed-in tariff for solar plants below 20 MW of capacity, which is 31.77 HUF/kWh (40% above the German support level).

All the member states of the region (also including Poland) are still in the initial planning stage of developing competitive procedures for 2017. This is not a coincidence since a large number of factors need to be considered when developing the auction system in order to arrive at a truly competitive auction design, while assuring a high probability of project execution. The table below provides a snapshot of only the most important issues with respect to the auction schemes.

Since a credible, proven European practice does not exist yet to uniformly answer these questions, and member states of the region have widely differing circumstances - such as differences in market size and financing opportunities (e.g. diverse levels of capital cost) - their caution is understandable. At the same time renewable support systems are under tremendous pressure with only four years to build the major new capacities needed to reach assigned targets.

Based on currently available plans, the AURES project has identified a number of common problems for the Central European region, and the most important are listed below:

- The auction systems to be developed must ensure the cost efficient operation of the support scheme without endangering the security of supply.
- Can the auction system ensure the development/maintenance of a sound investment environment and the desired technological diversification? The introduction of the auction in itself does not significantly reduce the investment risk of these countries, therefore future prices are expected to remain high e.g. above German prices.
- The biggest uncertainty faced by the member states of the region is the volume to be auctioned and the timing of the tenders. Since these countries are relatively small, creating true competition can be problematic: this would require a larger number of participants, which in turn needs larger volumes to be auctioned, exceeding the logical size for these small markets. How can this degree of uncertainty be handled?
- There are additional barriers in the region, especially concerning network development and connection to the network. These problems should be addressed before the first auctions are announced.

Table 2 Issues surrounding auction systems

What should be auctioned?	- technology specific / general competition - produced quantity / investment grant - fixed or variable premium - the length of the supported period, indexing
What is the volume to be auctioned?	- once or several times - deciding on the volume (limit set in terms of capacity or budget)
How to select the winner?	- based only on the price - also considering other criteria
How to determine the price?	- uniform/pay-as-cleared - pay-as-bid method
Should special bidding rules be applied?	- application of price ceiling/limit - setting quotas for specific technologies
What type of pre-qualification/ assurance should be required?	- pre-qualification criteria - specifying deposits, late payment penalties

In conclusion, the region follows the European trend with its country level plans: almost every country has made considerable progress in developing its auction system (with the exception of Romania where amending the green certificate system is not on the agenda). Nevertheless, none of the countries has launched an auction so far - not even as a pilot experiment - meaning the devised plans cannot yet be evaluated.

The pieces of the new domestic METÁR system

The goal of the third, closing day of the conference was to introduce and discuss (with the participation of the Hungarian representatives of the regulatory authority and the sector) the concept of the new renewable energy support system (METÁR) developed by the Ministry of National Development. In addition to analysing the main features of the new system, the conference paid special attention to the network integration of weather dependent renewable energy production. The panel of representatives of large corporations discussed the role that corporate strategy based renewable energy consumption may play in achieving domestic renewable targets. The MAVIR presentation reviewed the network integration of renewables, a topic that will become more critical with the continued growth of renewable energy consumption. The presenter concluded that the new METÁR system establishes a sound path that for Hungary to contribute to the achievement of Europe’s Energy Union targets.

On behalf of REKK, its director Péter Kaderják shared the most important conclusions of the REKK research project on the feasibility of domestic targets. The table below provides a summary of the potential role of specific regulatory instruments in achieving the 2020 targets of 13% and 14.65%. The table reveals that on top of current production at least 9.4 PJ of renewable electricity consumption should be added through METÁR, equivalent to the output of about 1200 MW of wind or 400 MW of biomass based capacity.

REKK evaluated several scenarios and factors leading to the attainment of the targets. Unambiguously, the final consumer price of electricity is impacted the most: under a cost efficient case the total support budget totals HUF 71.2 billion in 2020, 45% above the present level of renewable support. In all other scenarios the annual support requirement is even higher, touching the HUF 110 billion level in some cases.

Zsolt Szabó, secretary of state responsible for development and climate policy and key public services at the Ministry of National Development reflected on the new METÁR system. The legal framework of the new support regime that is compatible with the 2014 EU guidance was adopted by Parliament on 13 June 2016. The notification period with the European Commission starts afterwards, expected to be closed by the end of summer/early autumn. The new METÁR can come into force following the approval of the Commission. Meanwhile, the Ministry of National Development and the Government draft the lower level legislation.

Under METÁR the purchase obligation of the output of renewable power plants with installed capacity of more than 0.5 MW is terminated and new renewable capacities sell their electricity in the open market. Renewable producers with capacity between 0.5 and 1 MW may receive an administratively determined support (premium) on top of the market price of electricity, while the premium for producers with a capacity in excess of 1 MW is determined through a competitive tender. The introduction of the new METÁR does not impact power plants that are at present under the purchase obligation regime, plants with installed capacity of less than 0.5 MW, and demonstration projects which can continue to sell the generated electricity for a regulated feed-in tariff, to be set by a government decree.

Table 3 The targeted renewable energy consumption and the quantity to be acquired through the new electricity support scheme, TJ

	13% target	14.65% target	Comments
Gross final energy consumption	627 817	627 817	Based on the revised Hungarian Energy Strategy in 2015
Required renewable energy consumption	81 616	91 975	
Transport sector renewable energy consumption	13 448	13 448	Assumed a 10 % RES target in the transport sector
Electricity sector renewable energy consumption without subsidies	7 314	7 314	Production in 2015 – decommissioned PP + new PV without support
Heat sector renewable energy consumption without subsidies	48 115	48 115	Equal with the 2013 production level
Investment support	8 206	8 206	Assumed cost-efficient way of allocating the EU support budget
District heating regulatory reform	1 890	1 890	With an investment-friendly regulation, without any subsidy
Brown premium	3 965	3 965	Assumed the support of the present producers
Volume to be acquired through the new electricity support scheme	-1 322	9 037	METÁR (Hungarian new RES subsidy scheme)

Péter Grabner, vice president of the Hungarian Energy and Public Utility Regulatory Authority (MEKH) described some of the rules concerning the tenders:

- The annual volume of electricity to be tendered is set by a decree of the Ministry of National Development for the coming 5 years, in an annual breakdown and with annual updates - nevertheless, the volumes for the year in question and the subsequent year cannot be reduced. This introduces a significant stability into the system, which may reduce the premium demanded by renewable producers.
- The main conditions of a specific auction, that is, the duration of support and the supported volume are determined by MEKH, taking into account the annual volumes set by the Ministry of National Development. MEKH is also responsible for the execution of the tenders. The first tenders are expected in the first half of 2017 at the earliest.
- The adopted law allows the application of a number of barriers:
  - The announcement of technology specific tenders;
  - Setting annual maximum capacity limits for distribution regions;
  - Determination of maximum annual payments;
  - Establishing maximum and minimum limits for a given technology;
  - Capping the maximum offer price;
- Information on the application of the limits is not yet available and will be determined by the decrees to be developed in the future. Several questions arise in connection with the tender specifications, e.g. can limits change from tender to tender and what role will the Ministry of National Development have in determining them? These details are not yet known but the secondary legislation will provide clarification, likely during the autumn.

An important element of the new METÁR support system is the introduction of the brown premium to ensure that the previously developed renewable capacities would be maintained. The level of the brown premium needs to be updated annually, but the eligibility itself is granted for a five year period, and it can also be renewed. en setting the level of the brown premium the annual budget determined by the Ministry of National Development has to be considered (if they use this opportunity). The producer may choose one of two methods with respect to the brown premium:

- Normal brown premium: the difference between the supported price and the market reference price (which is established through a similar methodology as a tender). There is an annual cost revision also in this case, carried out by the MEKH.
- Alternative brown premium: The level of the brown premium is determined based on the difference between the costs of fossil fuel and biomass based combustion. The calculation also takes supplementary costs (e.g. the price of the CO_2 allowance) into account.

In sum, we can conclude that the framework of new, market based support system has been legally established, but the detailed rules are not yet finalised: the volume to be auctioned, the annual budget, and the specific rules to be followed during the tenders will be determined by the future decrees.

Guidelines on State aid for environmental protection and energy 2014-2020 (2014/C 200/01)

Russian gas pricing strategy

Gas prices in Europe dropped dramatically in 2015 and reached historical lows in 2016. At the same time, demand in the European gas market remained stagnant. In spite of this soft market environment, Russian deliveries to Europe managed to increase. This article provides an overview of the development of Russia's gas pricing strategy in Europe and projects the pathway that Russia/Gazprom is likely follow.

Historical background

Gas market trading was traditionally based on long-term supply contracts (LTC) between the exporting company (Gazprom or affiliate) and the vertically integrated importing utility, usually the monopoly supplier of gas in the respective European country. These contracts were backed in the Eastern European (ex-socialist) countries by inter-governmental agreements as well. The LTC provided insurance for the volume risk of the importer and the price risk of the exporter. Pricing formulas in the contracts were "one of the most well preserved secrets", negotiated between the two parties. This left room for Gazprom to apply discriminatory pricing between buyers, resulting in different gas prices for different countries according to the bargaining position of the buyer against the seller. Enjoying a monopoly position in most of its supplied markets (especially in Central and Eastern Europe (CEE)), Gazprom could set prices independent of market dynamics, the incurred cost and the "reasonable" profit margin, allowing for large price increases from one year to the next unjustified by any cost increase. That is referred to as discriminatory pricing in the competition law.

LTC pricing and oil indexation

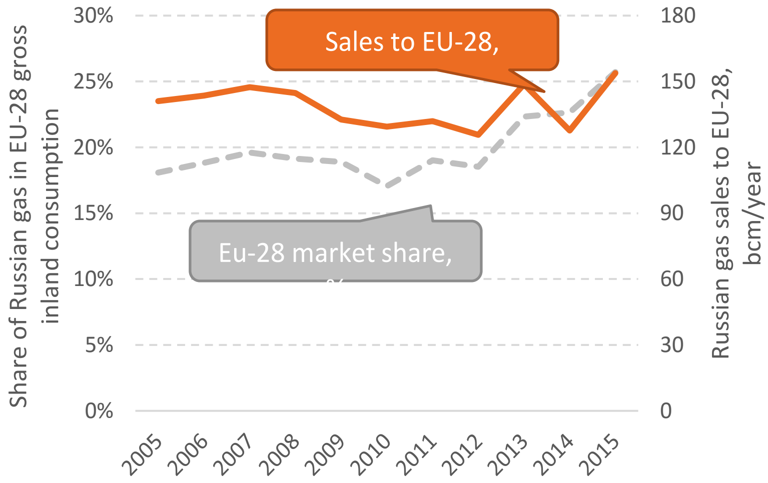
LTCs have traditionally been pegged to the price of oil, a link first introduced in the Netherlands when Dutch authorities priced the newly discovered hydrocarbon reserves to the price of substitutes (mainly oil products). The basic formula uses a starting price P0 of the agreed upon product and inflates the price of the product by the relative change of other fuels. LTCs utilised take or pay (TOP) obligations and destination clauses to ensure a steady cash flow for the financing of gas production and pipeline investment of the seller. This system was adopted by major players in the European gas markets and remained the dominant pricing arrangement even until 2005, when some 80% of gas traded in European markets was priced according to oil indexation. By 2015, this figure had plummeted to 30% with gas-on-gas competition accounting for 64% of all gas traded in Europe. The changes were most striking in Western Europe, but significant readjustment occurred in the CEE region as well. Meanwhile the Baltic and Mediterranean regions have not seen much change from the traditional model.

Market power abuse cases of Gazprom

European market liberalization and regulation has challenged Russia's traditional export business model and opened the retail market to competition. The European Commission applied the competition law to open a case against incumbent companies throughout Europe in 2007 (E.ON, RWE, ENI, GDF Suez and the Belgian company Distrigas), and afterwards opened an anti-trust case against Gazprom in 2011, accusing it of arbitrary and discriminatory pricing in countries where it was a monopoly supplier. The Commission focused its attention on the gas pricing in CEE (Case 39816), where Gazprom's exercises market power. Following a lengthy inquiry, the Commission sent a Statement of Objections to Gazprom in April 2015. The findings of the Commission focused on three main points: (ii) hindering cross-border trade with destination clauses written into sales contracts that force the buyer to use the purchased gas within its borders; (ii) applying unfair pricing policies in five CEE countries (Bulgaria, Estonia, Latvia, Lithuania and Poland), due to the fact that compared to several international benchmarks and Gazprom's costs, the Commission found that the oil indexed formulae approved in the region arrived to higher prices than in other markets. (iii) Using its market power and leverage to influence the gas infrastructure in Bulgaria and Poland. In Bulgaria, gas deliveries were ensured only if Bulgaria joined South Stream; in Poland, gas supplies were conditional only if Gazprom had control over investment decisions concerning the Yamal pipeline. As a result of the probe, the Commission could fine Gazprom to 10% of its annual turnover.

Gazprom refuted the Commission's findings in its official response and suggested that the case is politically motivated. The 2015 collapse in oil price made the oil indexed contracts more attractive, and the company maintains that even if the CEE countries were overcharged before they are gaining now from the low oil price environment. The Ukraine crisis has made the case more challenging and progress toward a mutually acceptable solution has slowed.

Figure 1 Market shares and annual sales of Gazprom to Europe



Re-negotiation of LTCs

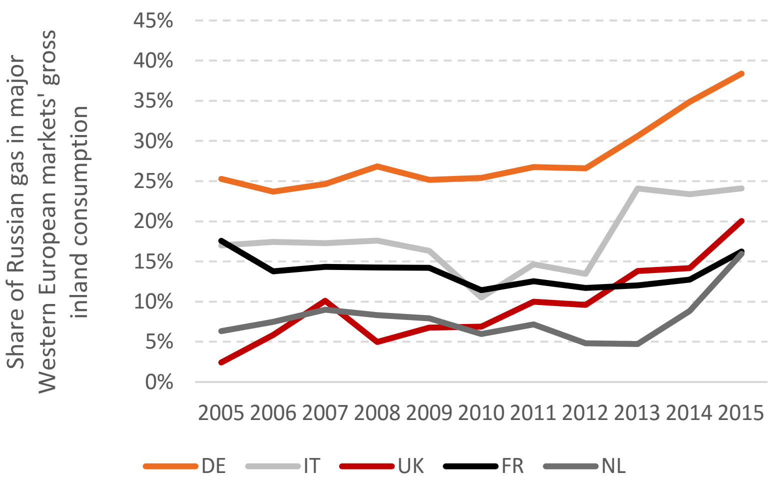
The oil-indexed contractual framework suited Europe in the absence of liquid gas markets when there was scarce gas-on-gas competition. However, after 2005 a number of factors changed the fundamental supply and demand dynamics in the European market. The shale gas revolution in the US redirected the LNG cargos originally intended for US customers to other markets, including Europe. For example, in 2007 the US imported 770 000 MMcf LNG (~21-23 bcm of natural gas), and this fell to just 90 000 MMcf in 2015 (~2.4-2.7 bcm), shrinking the market size tenfold. Meanwhile the 2008 crisis caused demand to drop across Europe, forcing the various gas suppliers into more fierce competition. Gazprom was keen on keeping its market share and open to renegotiations. Gazprom arranged renegotiation of LTCs with its largest customers on more favourable terms, included discounts, greater incorporation of spot-based price components in the oil- indexed prices, re-setting the P0 starting price of the contract and the introduction of 'price corridors'. From 2010 on, Gazprom renegotiated on average 10 contracts annually. It is telling that in markets where its position was threatened by other market players, fundamental renegotiation took place that affected the terms of the contract (eg. in Germany, Italy, the Netherlands). In other markets, where Gazprom was the single supplier, only a one-of discount was negotiated (eg. in Estonia, Latvia, Lithuania, Bulgaria, Serbia). By the use of these instruments, Gazprom managed to maintain its market share when it was necessary.

Current market characteristics

Gazprom has shown a willingness to make adjustments to the changing market (demand drop due to the financial crisis and supply glut due to the shale gas revolution) and regulatory environment in Europe (third party access rules, cross-border trade and prohibition of the destination clause in long term contracts) by shifting its market strategy and renegotiating LTCs. Most importantly a gas-to-gas competition element emerged in the pricing formulas of Russian contracts, correlating roughly with the competition Gazprom has to face in the respective markets.

Retail competition has empowered consumers, and competition from other fuels, especially renewables in electricity generation (electricity generation accounts for about 25% share of total European gas demand) reinforced the shorter and more flexible contract structure. At the same time European competition authorities have urged Gazprom to adapt its business model to new market realities. For these reasons, Gazprom started to auction volumes on Western Europe trading hubs on a short (yearly) term basis. These quantities (~2 bcm per year) are below 5% of the total annual volumes sold to Europe but are promising signs for the adaptation strategy of Gazprom to the new trading mechanism.

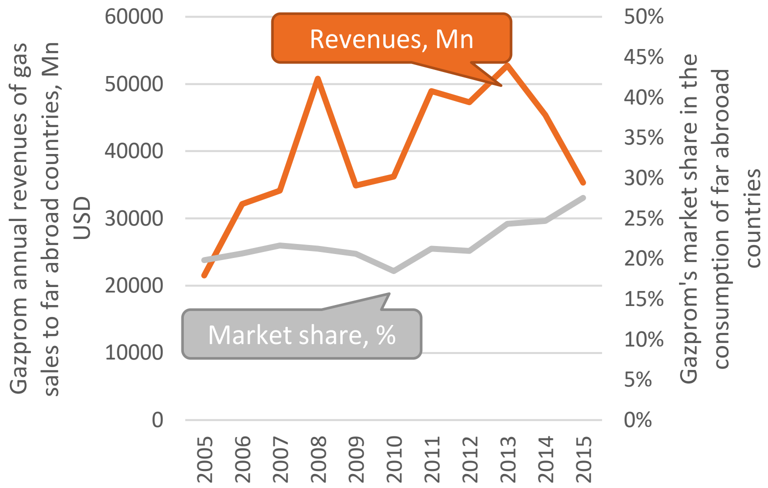
Figure 2 Gazprom's market share in some major European countries



Price equalization in Europe

According to the quarterly report of the European Commission concerning gas markets, in 2012 the difference between the cheapest and the most expensive Russian long term contracted gas amounted to 15 EUR/MWh. In 2015, this dropped to 8 EUR/MWh, and below 7 EUR/MWh in 2016 Q1. This convergence was mainly caused by the drop in oil prices.

Figure 3 Annual revenues and market share of Gazprom



Russian market share, prices and deliveries to Europe

To quantify the above mentioned changes in the natural gas markets of Europe, a simple analysis is performed regarding market shares, prices and deliveries of Gazprom volumes. We define the Russian market share in each country by dividing the annual imported quantities from Russia with the annual consumption. This metric considers not only the pipeline competition of Gazprom but also inter-annual storage utilization and domestic production as a competitor. In the 2005-2015 period, Gazprom managed to increase its market share beyond 25% of the total EU-28 consumption, mostly attributable to falling EU production that required more imports.

In these major markets, the company managed to raise its market share 5-15% from 2013 to 2015. Nevertheless, it came at a high price for Gazprom as its revenues plummeted from 50 bn USD in 2013 to 35 Bn USD in 2015. Even though Gazprom delivered the same amount of gas to Europe as in 2013, its revenues dropped significantly. While in the 2005-2012 period Gazprom faced little competition and the oil price environment was favourable for the company, from 2013 to 2014 EU-28 consumption dropped 10% year-on-year, coupled with the global oversupply of LNG and a low oil price environment. The drop of global oil prices eventually made oil-indexed contracts more favourable relative to spot gas products and LNG in the short term, thus buyers of LTCs started procuring more of the annually contracted volumes within the flexibility range stated in the contracts. The increase in relative market share of Gazprom may be partly attributed to this phenomenon.

Possible strategies of Gazprom: market share vs revenues?

In oligopolistic markets, market participants tend to follow the goal of profit-maximization. This means that if few companies are present, such as in the European gas market (Russia, Norway and Algeria being the biggest suppliers with Qatari LNG and US LNG as a marginal player), market players may exert their market power in order to achieve higher revenues than compared to a more competitive market setting (e.g. more diversified sources of supply having smaller market share). Moreover, the European gas market cannot be characterised as a single market, as existing pipeline constraints, transmission tariffs and contractual obligations may inhibit the flow of gas from one state to another. In separate regional or national markets competition between the big three suppliers differs; for the gas markets of Portugal and Spain Gazprom may not be a competitor for Algeria and similarly Algerian gas will not crowd out Russia deliveries in the Baltics.

The Russian strategy may not always pursue the goal of short-term profit maximization. In some strategically important markets, it may be concerned with upholding its market share against other potential entrants, by granting discounts to its buyers or by marketing non-long term contracted gas at a favourable price even if this would mean a lower revenue compared to its LTC model. This strategic response could have a long run payoff, however, by limiting market access to other players and alleviating the competition effect.

We argue that:

- There is not a single European gas market but a set of regional and national markets. Better interconnectivity and harmonised trade rules will help to further market integration, but currently the hardware and software of the European gas network is inadequate to support a single market.
- Due to this fragmented nature, strategic players may exert different leverage

between these sub-markets.

- Gazprom maximizes profits in the short run if no other competitor is present and considers a market share strategy if other players are present in the market or poised to enter.

For now, Gazprom is not losing its market share in Europe because it is replacing falling European production. In its major Western European markets which are developed and more liquid, Gazprom can offer a lower price to achieve its market share goal in the face of greater competition.

Challenges for Gazprom: LNG and competition charges

In the recent years, Gazprom managed to sustain and expand its market share in most European states. The commissioning of the LNG liquefaction terminals in the US and the start of LNG exports in early 2016 will have an effect on the European gas markets. Originally, the US LNG terminals aimed to deliver their cargoes to Asia, but slowing economic development in China, parallel Australian LNG trains coming online, and the restart of Japanese nuclear power have made the Asian premiums disappear. In the first half of 2016, only two cargoes were delivered to Europe, with the bulk of the gas transported to South America. These two cargoes were delivered to Spain and Portugal, totalling ~200 mcm of natural gas altogether. Clearly, LNG does not endanger Russian market share in Europe yet, since such volumes are not enough to influence the price on the one hand and cargoes have not reached the regional markets relevant for Russia on the other hand. In the medium term however, US LNG will have greater effect on Europe with another five LNG trains to be commissioned until 2020.

The other challenge for Russia is resolving the anti-trust case brought against it by the European Union. The probe against Gazprom found market power abuse cases and required Gazprom to elaborate these claims and end their practices. Gazprom claimed that the charges were unfounded but is open to cooperation. We argue that the European probes threaten Gazprom's traditional mode of operation by limiting its ability to segment European markets.

Perspectives of Gazprom in a competitive environment

European domestic gas production is dwindling – by 2020, a 15% drop (~20 bcm/year) is expected mainly due to the new cap on Dutch gas production in Groningen. These volumes will be alleviated by either a fall in gas demand or new import sources. The possible candidates are current suppliers to Europe (Algeria, Qatar, Russia and Norway) and the new entrant US LNG. The current regulatory environment and growing transparency afforded by European trading hubs make it easier for new players to enter markets at lower costs than before. Qatar and Algeria are extremely rigid in their long-term supply contracts and do not exhibit the market share objectives of Gazprom while Norwegian sales have essentially aligned with TTF prices. The US follows a Henry Hub plus transport cost strategy.

Although the market is contestable, the short run marginal cost of production favours Gazprom and other players are likely unable on engage in strategic competitive games: in 2015, average production cost of Gazprom was 0.8 USD/MMBtu, considering transport and other charges, which translates to about 3-4 USD/MMBtu at the German border. US LNG is a worthy competitor, but its minimum cost is affected by several factors: the Henry Hub price, variable cost of liquefaction, shipping and regasification. In 2015, the average Henry Hub price amounted to 2.6 USD/MMBTU, liquefaction was 1.5 USD/MMBtu while shipping to Rotterdam and regasification was around 0.5 USD/MMBtu each – adding up to 5,1 USD/MMBtu. Changes in the US natural market and the world LNG market directly affect the competitiveness of US LNG, which exhibits price taking and no strategic dimension. Norwegian production costs amounted to 1.04 USD/MMBtu, with Norway following a price-taking strategy on the market, and opting against a market share maximising strategy.

In our view:

- Gazprom has the ability to start a gas competition and could prevent new players from entering the market, but at a high cost: lower prices would result in lower profits for the company and might endanger its myriad of infrastructure investment plans that are crucial for Gazprom to serve European demand
- Gazprom will exercise its market power to the maximum degree possible as long as European competition and regulatory scrutiny allows: long term contracts will remain the dominant form of wholesale market trading in the countries where markets are underdeveloped and diversification options are limited and pricing will reflect the negotiation power of the buyers. In the more competitive markets Gazprom will adjust to the circumstances, and reduce prices to keep its market share.

The role of energy storage within the electricity system of the future

Energy storage in Europe is gaining more attention in conjunction with the climate objectives of the European Union. Storage can play an important role in the decarbonisation of the electricity sector by improving the integration of intermittent, weather dependent renewable sources and better aligning production with consumption. Moreover, the total capacity of the electricity system does not have to match peak consumption or be adapted to the peak generation of renewables. This allows for savings in the expansion of generating capacities as well as the development of the transport and distribution infrastructure. Storage also has the potential to be commercially viable since it enables the sale of electricity during periods of high demand, and thus high prices.

Under the decarbonisation scenarios of the European Commission the share of renewables within electricity generation will rise to between 59% and 85% by 2050.[1] With the expansion of weather dependent renewables the electricity networks need to prepare for a number of changes. The gap between demand for electricity and renewable production, the so called residual load, can be met with electricity from conventional power plants or from storage. Power generation in the short run may increasingly deviate from forecasted values, while system inertia - mitigating frequency fluctuations - declines. The existing transmission and distribution network capacities serve increasingly as limitations when they are unable to cope with growing renewable production. The flexibility of electricity systems - traditionally designed to handle changes in demand - increasingly has to serve the fluctuations of supply.

In Germany there are more and more days when consumption is low but generation remains high (such as windy weekends or public holidays), which results in negative electricity prices on the exchange. In other words, the producer has to pay in order to be able to feed its electricity into the network. This problem is not limited to producers as, for example, one of the German network operators indicated that it does not possess the financial resources to upgrade the infrastructure to accommodate further offshore wind farms. In Denmark, which is also home to substantial wind capacities, there was an instance when wind based production had to be curtailed to ensure district heating because combined electricity and heat generation cannot be switched off, even when electricity demand could be satisfied by renewable sources alone. The above is a clear sign of the inefficiency of the present system and points to the clear need for more flexible storage systems.

The state of storage today

The most prevalent storage systems today are based on different principles than those that are needed for the integration of renewable energy sources.

Table 1 Utilisation options for electricity storage facilities

Type of the storage service	Characteristics
Large scale storage	Large size (>>MW - >GW)
	Discharge time: up to tens of hours
Integration of renewable energy sources	From medium to large size (100 kW to 100 MW)
	Discharge time: from minutes to several hours
Ancillary services (e.g. frequency and voltage control, system reserve, support for power plant restart)	From small to medium size (>10 kW to 100 MW)
	Discharge time: from seconds to hours
Transmission and distribution (e.g. to alleviate network congestion, avoid interruptions, support infrastructure for vehicles equipped with pantograph)	From medium to large size (MW to 100 MW)
	Discharge time: from minutes to hours
Consumer energy management (e.g. maximising consumption of own generation, reducing peak demand, integrating electric vehicles)	Small or medium size, not necessarily network connected (kW to MW)
	Discharge time: from minutes to hours

1 Energy Roadmap 2050: Impact assessment and scenario analysis

Table 2 Energy storage technologies connected to the grid in Europe

Technology	Installed capacity (MW)
Pumped storage power plant	43700 MW
Compressed air storage	290 MW
NaS battery	a few MW
Lead acid battery	20-30 MW
Lithium-ion battery	about 20 MW
Flow battery	about 1 MW

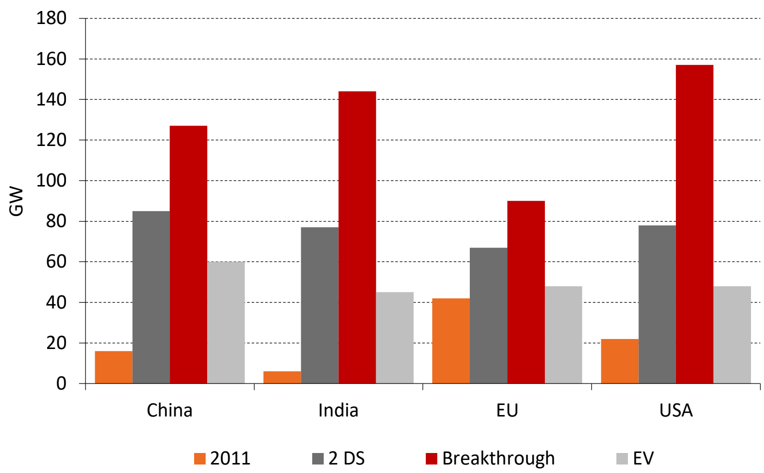
These so called pumped storage power plants were built between the 1960's and 1980's by integrated companies (active in production, transmission, distribution and energy supply) to replace part of their peak period production. During the 1970's the investment costs of pumped storage power plants and combined cycle gas turbine (CCGT) plants - today viewed as the most suitable technology to meet peak demand - were about the same, while the former had a lower operating cost, and therefore represented a more attractive alternative.

Due to the increasing efficiency and declining investment costs of the CCGT technology, by the early 2000's its cost fell by about half, while its execution was faster facing less administrative burdens (such as permitting and environmental) and not being subject to the geological constraints typical for pumped storage power plants. The development and deployment of energy storage technologies therefore almost completely halted and almost no new capacity has been created over the past 25 years. Storage development was also hindered by the relative decline in price of peak period electricity compared to the price of the baseload product.

This explains why today 98% of the 145 GW of globally available storage capacity on electricity grids is in the form of pumped storage power plants. The situation is similar in Europe, where pumped storage represents 95% of the close to 50 MW of storage capacity. These, together with compressed air and flywheel storage, belong to the category of storage based on the principle of mechanical operation. Two additional categories should also be distinguished: electrochemical storage (traditional batteries; modern batteries such as lithium-ion or sodium-sulphur batteries; flow batteries) and electro-magnetic storage (superconducting magnetic storage, supercapacitors). Only pumped storage power plants and compressed air storage solutions are characterised by large capacity (up to several GWs) and long energy output (up to dozens of hours); the rest of the technologies may contribute to the elimination of minor, local imbalances of the network and some of them are available for households to optimise their own production (such as photovoltaic) and consumption.

Two important features of storage technologies are the amount of energy they can store (MWh) and their power capacity (MW). The ratio of these two variables (power-to energy ratio) determines the duration for which a given facility can supply energy. The ratio typical for pumped storage power plants is 1:8; a 100 MW facility capable of providing this output for 8 hours. The absolute values of the capacity and the ability to store energy as well as their ratios influence the type of service that a facility can provide. For storage facilities, efficiency is defined as the percentage of the stored energy that the facility can supply again: its value can vary between 40% (compressed air storage) and almost 100% (lithium-ion batteries, supercapacitors). Modern pumped storage power plants operate at an efficiency of 85%.

Figure 1 Daily electricity storage capacity in 2011 and in 2050 in accord with the 3 IEA scenarios



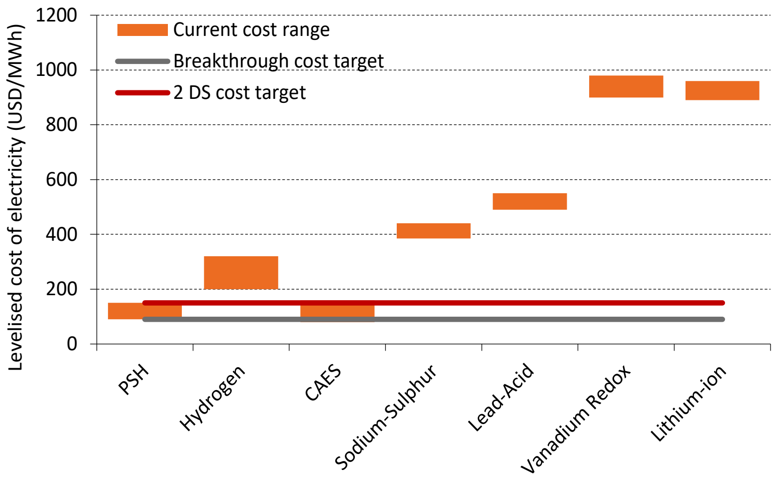
The scenarios of the future

According to a study published last year endorsed by 32 energy corporations and organisations, assuming at least a 60% share of weather dependent renewables, up to 10 times of the current storage capacity (or about 400 GW) may be needed in the EU by 2050. The authors believe that even at this level substantial fossil fuel generating capacities may remain in the system,

2 Utilisation of the surplus energy, nevertheless, may be solved through electrolysis, a technology that turns electricity into hydrogen. Hydrogen can be stored outside of the electricity system and it can be utilised by feeding it into the gas network, by generating electricity, but also within industry and transportation. By 2050 the European electrolysis capacity may reach 170 GW, while the annual volume of produced hydrogen may grow to 5 million tons.

and the volume of energy from renewable peak production that will not be utilised through consumption or storage may also be significant.[2] This is because storage capacities can be established only at decreasing economies of scale: in order to reduce the necessary fossil based reserve capacity by two-thirds, the storage capacity would have to increase four-fold. Moreover, it must be determined if storage is used to minimise reserve generating capacities or to integrate as much renewable energy as possible. In the former case the storage facility has to be fully filled and ready to be deployed, seriously restricting its operation under the energy output mode.

Figure 2 The current and expected 2050 level of storage costs



The study provides firm figures for Germany: without storage renewable production that cannot be utilised would amount to 173 TWh - or almost 30% of the total electricity demand - and 85 TWh (15%) of non-renewable generation would be needed in 2050. Instead of the currently available pumped storage capacity of 7 GW, with 64 GW of storage capacity the need for non-renewable production would shrink to 49 TWh, generating annual savings of EUR 4.2 billion from the costs of fuel and CO_2 emissions. According to the study this sum - under an optimistic scenario of cost estimation - is equivalent to the annualised investment and operating costs of the storage.

The increasing need for storage may, of course, open the way for technologies that are used less widely today. Pumped storage power plants can only be constructed in locations that contain certain geological features and society's willingness to accept them can be low on environmental grounds. In Hungary, for instance, according to the Ministry of National Development suitable locations are all nature protection areas, therefore this solution is out of question. Moreover, while pumped storage systems can also quickly react to imbalances within the electricity network - modern facilities switch between pumping and generation in less than 15 seconds - the integration of renewable energy sources is better facilitated by a larger number of smaller, decentralised storage facilities. This is because current infrastructure producers like those operating pumped storage power plants are connected to the high voltage transmission network, while consumers are on the lower voltage distribution networks. The utilisation of renewable energy sources, however, provides room for smaller units of decentralised production that are connected to the distribution network, requiring corresponding solutions in storage as well.

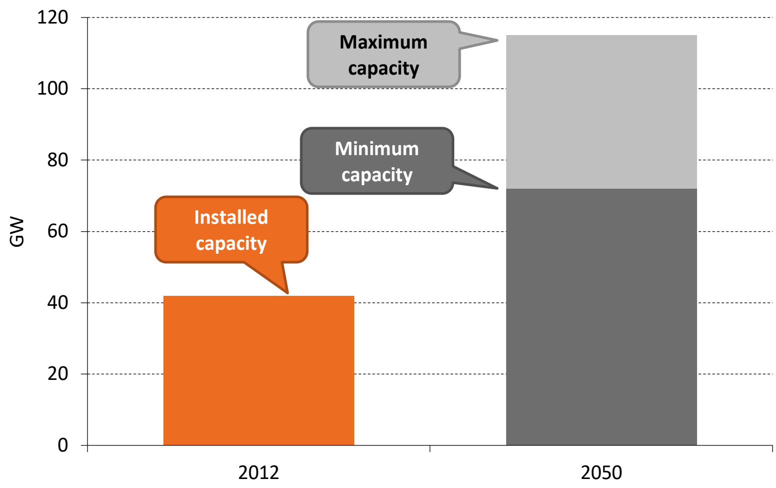
Of the grid based storage technologies in Europe, presently the electrochemical and heat storage technologies proliferate faster, in contrast with global trends. The rise of heat storage is related to the expansion of concentrated solar power plants (CSP) mainly in Spain; the surplus production of these power plants is stored as heat, e.g. in molten salt. Batteries, at the same time, become more important in supporting transmission and distribution networks necessary to integrate renewable generation.

Forecasting the storage potential is made difficult by a number of factors, of which the uncertainty related to technological development and the evolution of costs is only one. According to the International Energy Agency (IEA) reference scenario, by 2050 the levelised cost[3] of storage technologies will sink to the cost level of pumped storage power plants, which is the cheapest storage technology today. This vision is based on the assumption that by 2050 65% of global electricity production will be renewable based, and 29% weather dependent renewable (the latter ratio would approach 45% within the EU). As a result, global warming could be capped at 2 °C with a probability of 80%. Under the scenario of technological breakthrough energy storage becomes competitive with CCGT power plants, the cheapest flexibility technology available today. The IEA notes, however, that in order to achieve this, the cost of batteries should decline at an extremely steep rate to less than 10% of current costs.[4] Under the third scenario demand side flexibility curbs the need for

3 This is the levelized cost of electricity (LCOE) with a similar meaning as in the case of generating technologies; the unit cost of energy released from the storage facility during its full lifetime, considering investment as well as operating costs.

4 In the field of electrochemical technologies there is room for substantial technological development and cost reduction primarily with lithium-ion and flow batteries. At present, however, the European R&D potential is robust in the sphere of traditional batteries, while Asian countries dominate the lithium-ion technology.

Figure 3 The expected expansion of European storage capacity



weather dependent capacities of production and thus storage. Likewise, the penetration of other, more predictable renewable technologies (e.g. tidal or geothermal power plants) may have the same impact. As the IEA notes in relation to its scenario based on demand flexibility, the penetration of controllable load and smart networks may make it possible to increase demand in line with the growth of weather dependent production, reducing the need for storage.

storage with technological innovation, and 25% of the daily electricity need for electric cars becomes controllable load.

As Figure 2 shows, even under the most optimistic scenario, the IEA forecasts only slightly more than one-quarter of the European storage potential envisaged by sector players. The latter think that even 400 GW of capacity is conceivable, although that would be based on a weather dependent renewable ratio that is at least 15% above the IEA figure. With respect to uncertainties, the IEA notes that in the absence of a comprehensive global database, information even on the currently existing capacities is imperfect. An additional problem according to the IEA is that sufficiently detailed (hourly or more frequent) data is not available on renewable energy production, heating and cooling demand curves and the quantity of residual heat. Such data would be necessary to properly represent system behaviour on a longer time horizon.

The impact of the future development of network infrastructure is viewed by sector players as the most critical piece of uncertainty. The need for storage would be substantially lessened if such developments would erase bottlenecks and, as an example, hydropower from Sweden or Spain could have a role in balancing German weather dependent production. Another source of uncertainty is that with the development of solar and wind power technologies the amount of energy that can be generated during feeble periods of wind or sunshine may increase, reducing the supplemental capacity required for a given level of production, as well as the surplus energy that has to be stored. Once biomass based power plants become more flexible and more widely applicable, they may also displace

There are 23 storage projects within the newest 10 year development plan of ENTSO-E, and these projects together would boost the European storage capacity by 19 GW. The overwhelming majority of the projects (19 of them with 18 GW of capacity) are pumped storage and compressed air facilities; the remaining 1 GW is shared among three battery based projects and one melted salt project. The ENTSO-E notes that economic circumstances are not favourable for the development of pumped storage power plants because the large scale generation of renewable energy suppresses peak power prices. Of the four visions inspected on the 2030 time horizon, two mentions storage. In the absence of a European framework to promote storage, the vision called "national green transition" does not expect significant new capacities, only "some" national progress. The "European green revolution" scenario includes full scale application of smart metering and smart networks, therefore demand side adaptation may play an important role. Also under this scenario, additional water based storage capacities are created "in a centralised fashion" (the meaning of which is not explained in detail) mainly in Scandinavia, the Alps and the Pyrenees.

Interestingly, even in the long run, ENTSO-E considers only mechanical storage technologies. According to the e-Highway2050 project, carried out with the participation of the European association of system operators and a number of TSOs, of the commercially available technologies only these have capacities in excess of 100 MW, while batteries "show signs of aging and are difficult to recycle".[5] The forecast included in the project summary modelled all new capacities using the characteristics of pumped storage power plants.[6]

5 Of the many sections of the project only one covers storage specifically, and even that only deals with compressed air technology.
6 A related analysis, nevertheless, makes it clear that the forecasted capacity expansion is also viable through other technologies, as long as they are „economic and environmentally acceptable". Compared to the assumptions of the project, this may influence the specifications and locations of storage facilities..

According to the study the summer balancing of the Spanish PV production would require the daily storage of about 70 GWh of energy which would cost EUR 20 billion, assuming that 10 million pieces of 7 kWh batteries would be installed at a cost of EUR 2,000 each. This is much more than developing the network or constructing peak power plants. Moreover, the authors claim that expanding daily storage capacities is not necessary in "countries like Germany or France", or in the Southern countries during the winter period, since in these locations there is not any significant excess PV generation during the day. Thus the substantial, prexisting storage and demand flexibility capacities are sufficient to balance production. The study, nevertheless, does not say anything about the balancing need of wind power.

Regulatory questions

In addition to the future costs of the storage technologies and the development of network infrastructure, the regulatory uncertainty makes forecasting difficult. According to sector players biggest issue is that the EU directive on electricity does not identify storage, and the absence of storage specific rules acts as a major obstacle to investing in expanding the capacities. One of the most serious consequences of this situation is that most member states view storage as a combination of consumption and production, therefore it has to comply with relevant requirements of both modes of operation. According to the 2012 EURELECTRIC summary, pertaining specifically to the pumped storage power plants, there are countries where these installations have to pay network tariffs twice. There is also a case in which the tax on final consumption is imposed on storage use.

An equally serious problem is that in most member states, as far as the rules on separation, TSOs and DSOs are not allowed to operate storage facilities. Given that most storage services balance the network and optimise the system as a whole, they can mitigate network investments. This may explain why storage is not even mentioned in the RES integration chapter of the ENTSO-E TYNDP executive summary, published in 2016. Only a quote from Greenpeace is displayed, according to which it is cheaper to develop the transmission network than investing into the necessary generating or storage facilities.

Regulation is made more difficult by the fact that a given storage facility may offer a diverse set of services, each of which requires a different regulatory approach. A fundamental difference, for instance, is whether a given service is sold by the storage facility on the competitive market or at a regulated price. In fact, the European University Institute concluded that under current market conditions the storage facilities are not viable based on a single service, therefore the development of a proper regulatory framework is inevitable.

Sector participants examined the viability of seven business models and concluded that two out of the seven can already be successful today using optimistic cost estimates. Large scale, mechanical storage technologies (pumped storage, compressed air and liquid air storage) can provide a financially attractive solution in frequency control, while lead acid batteries can be viable options for the integration of household PV generation.[7] According to the study, however, the model based on balancing between the daily peak and off-peak periods is not economically feasible since the price difference is not large enough compared to the potential LCOE, and the spread could fall further with the entry of additional storage facilities. This is in line with the position of ENTSO-E, which stated that because feeding large volumes of renewable electricity into the grid suppresses peak prices, economic conditions are not favourable for the development of pumped storage power plants. The declining spread is partly driven by the financial agreements that aim to retain reserve capacities within the system. Current conditions may further deteriorate if European regulation moves toward the establishment of capacity markets.

Due to the penetration of renewables, the expected rise of CO_2 costs and the decline of technological costs, most of the inspected models may become profitable by 2030. Yet concerned companies and organisations believe that regulatory changes will also be inevitable. As an example, in order for electrochemical technologies to have a role in frequency regulation, the rule according to which the offered reserve has to ensure service for at least four hours should be relaxed. A fundamental precondition to the viability of storage aimed at avoiding wind power generation restraints and the use of surplus energy is a regulation that does not award revenue to the producer when the system operator has to restrict the output of the power plant.[8] If the goal of storing wind power is to assure that generation can be forecasted for the period of at least a few hours („firming"), then a regulation with corresponding incentives is needed; wind power plants are usually not interested in improving the predictability of their production due to preferential network access. The

7 According to the study lithium-ion batteries are also approaching the point of profitability in this field

8 According to the study, however, this business model is not expected to become viable by 2030 even if this condition is satisfied, because due to the special pattern of wind based generation - multi-day periods of increased production followed by days of scaled back generation - it requires storage technologies with a large capacity compared to their energy output performance. This means that during their lifetime these facilities complete too few storage cycles to recover the investment cost.

profitability of storage connected to household PV systems could be further improved by the introduction of "time of use" tariffs.

The forthcoming EU level network code of balancing markets may be an important step toward the increased role of storage facilities. The most recent version proposed for adoption by ACER will be presented to the Commission and experts of the relevant member state ministries. It says that TSOs have to allow the operators of storage facilities to enter the market of balancing services, and that their market participation should be assisted with the development of standard products. The draft formulates a similar requirement for the so called aggregators which group small producers and consumers to reach the size necessary for balancing. This may turn out to be important for future central management of different flexibility instruments including storage.

The efficient operation of the balancing and intraday markets has also been judged as critically important by the European Commission in its consultation paper on the recommendations for the new electricity market model (publication is expected by the end of the year). The document highlights storage, declaring that its integration into the electricity market would boost the efficiency with the expansion of renewable generation. It emphasizes the importance of gaining access to long term markets, which would provide appropriate information for storage facilities when investment decisions are made.

The EC notes that current regulatory barriers and discriminatory rules must be addressed so that consumers and aggregators are in a position to appropriately utilise the instruments of demand side flexibility (such as storage). For now, they cannot participate in the electricity market on an equal footing with producers. They will need to in order to meet the vision of the EC, by becoming active market participants through technologies like storage, smart networks, smart metering, smart home and household energy generation, and ultimately reducing the electricity bill for consumers.

REKK publications in international journals

András Mezősi - László Szabó: Model based evaluation of electricity network investments in Central Eastern Europe

Energy Strategy Reviews Volumes 13–14, 2016

The paper analyses the complex welfare impacts of proposed transmission investments in the Central Eastern Europe (CEE) region with the application of the EEMM electricity model. This assessment is made at regional level, as new transmission lines have significant spill-over effects over third countries. We carry out a cost-benefit assessment (CBA) focused on the CEE region and demonstrate, that the EEMM model is a suitable tool to carry out such assessment. Using a simplified CBA – limited by the available information on the projects – we mimic the process of identifying those transmission lines that increase the regional welfare the most. In addition, the paper also identifies those methodological and policy issues, that have significant impact on the results, and must be applied consistently during the evaluation process in order to gain robust results. Our results indicate that new infrastructure elements cause significant and asymmetric wealth redistribution among group of stakeholders and between countries as well. Interactions between planned transmission line developments must be identified, as they could significantly change the benefits of those lines connecting the interlinked markets.

Zsuzsanna Pató - András Mezősi - László Szabó: Fossil or hydro based capacity development? - Power sector modelling in the South-East European Region

EEM 2016 conference

This paper analyses the impact of current generation and interconnection capacity plans on the generation mix of the five South East European countries (Albania, Bosnia and Hercegovina, Macedonia, Montenegro, Serbia) in the context of carbon price levels and assesses the conditions for the exploitation of the existing hydro potential. Future electricity mix of the five countries are analyzed – using the European Electricity Market Model (EEMM) of REKK - for 3 scenarios up to 2030 assuming different conditions for electricity supply and demand. We have found that vulnerability due to weather dependent hydro generation is a relevant policy issue that needs to be tackled if the available hydro potential is to be exploited more in the future in the SEE region. Higher interconnection would allow for import even in dry years with a more limited number of new coal plants actually planned in the region as countries would have unconstrained access to them.

András Mezősi - Zsuzsanna Pató - László Szabó: Assessment of the EU 10% interconnection target in the context of CO2 mitigation

Climate Policy 2016

The European Commission has proposed the target of achieving an interconnection capacity of at least 10% of the installed electricity production capacity for each Member State by 2020 in the context of the envisaged Energy Union. The underlying objectives are to increase the security of supply at affordable prices via market integration and to contribute to decarbonization by accommodating an increasing level of renewable generation. In this article we have assessed whether this target could effectively fulfil these two objectives. Our main focus is on the assessment of the impacts of compliance with the 10% interconnection target on the carbon emission of the European electricity system. Our main research question concerns the impact of interconnection capacity increases on EU carbon emission due to the better market integration, disregarding the RES-E integration aspects. In order to arrive at workable scenarios for the future cross-border capacity extension, the security of supply and market integration impacts are also assessed.

We concluded on the basis of our European dispatch model that full compliance would slightly increase carbon emission in the EU, ceteris paribus. This impact is due to increased coal- and lignite-based electricity production, mainly in Germany, Poland and the Czech Republic. By increasing the interconnections of these countries with their neighbours at the present low carbon price under the EU emissions trading scheme, these carbon-intensive electricity systems run on higher utilization rates and consequently increase carbon emission. It has to be emphasized that the increase is found for the current situation, and changes in other factors, such as increases in carbon prices or renewable generation, could modify this result.

Our results demonstrate that EU network development and climate policies are highly interconnected. Changing patterns in the interconnections of the EU electricity systems connect diverse generation portfolios and in a low carbon price environment could increase carbon emission at the community level. Policy makers should be aware of the interactions between these areas and design policy tools that also consider negative synergies.

Jan Rosenow - Cor Leguijt - Zsuzsanna Pató - Nick Eyre - Tina Fawcett: An ex-ante evaluation of the EU Energy Efficiency Directive - Article 7

Economics of Energy & Environmental Policy 2016

The European Union's Energy Efficiency Directive calls for EU Member States to put in place ambitious energy efficiency policies and requires them to establish energy saving targets. One of the most important Articles of the Directive is Article 7, which required Member States to implement Energy Efficiency Obligations and/or alternative policy instruments in order to reach a reduction in final energy use of 1.5% per year. This paper assesses how Article 7 has been applied by Member States and what the implications are. Analysing the plans of all 28 Member States we evaluate how Article 7 is implemented across the EU. This includes an analysis of the types of policies used, the distribution of the anticipated savings across the different policy instruments, and whether or not the way Article 7 is applied in reality meets the requirements set by the Directive. Our analysis shows that Member States take very different approaches with some using up to 112 policy measures and others just one. We also identify areas of concern particularly related to the delivery of the energy savings with respect to the Article 7 requirements, the calculation methods, and the monitoring and verification regimes adopted by Member States. We model to what extent the projected savings are likely to materialise and whether or not they will be sufficient to meet the target put forward by Article 7. In our paper we also make suggestions for modifying the Energy Efficiency Directive in order to address some of the problems we encountered.