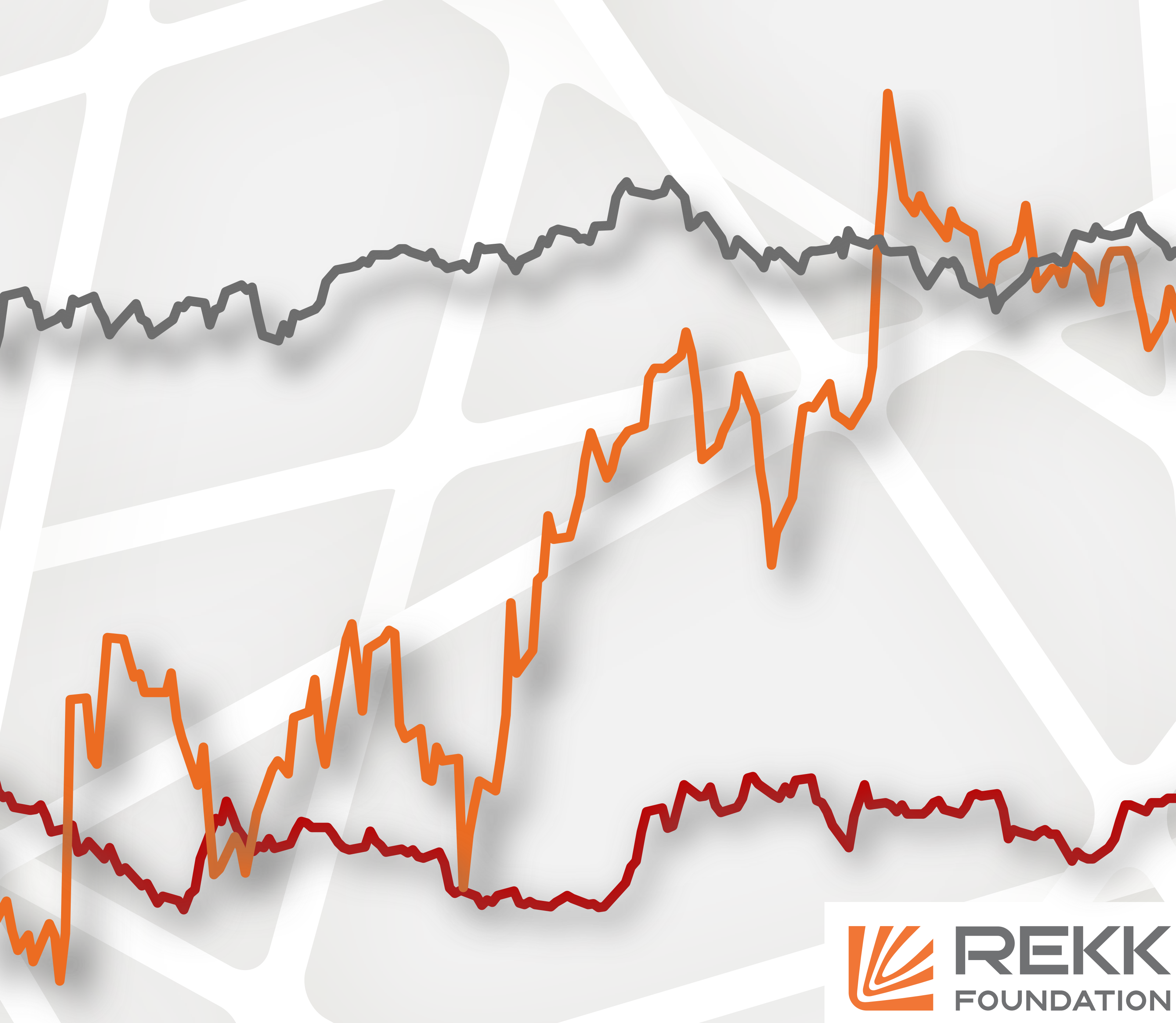

REKK FOUNDATION

HUNGARIAN ENERGY MARKET REPORT

Q1 2017

Dear Reader,

Our energy market report keeps you up to date on the latest developments in EU legislation and they how they are influencing the outlook for domestic energy markets. This report reflects specifically upon the European Commission's „Winter package" proposal from November 30th last year.

The most important proposals update the design and operation of the internal electricity market, the directive on renewable energy production and energy efficiency, and the draft regulation on competences and responsibilities of the Commission and Member States regarding energy and climate policy targets.

Before introducing the proposals that have received the most extensive media coverage and attention of energy market players, we would briefly remind our Readers of the related legislative developments in the past two years that have led to this point.

In the summer of 2015, the Commission published its proposals on the future regulation of electricity markets, which have since been articulated in draft legislation. This Summer package included the proposal on modification of the Emission Trading Scheme (ETS), seeking to boost CO_2 prices by narrowing the allowance supply.[1]

In less than a year, February 2016, the first winter package was published focusing on the natural gas sector, introducing the Commission's strategic concepts on security of natural gas supply, storage and LNG imports. The Winter package – despite this moniker suggesting a comprehensive package of proposals – includes only one proposal on the modification of Security of Gas Supply Regulation. In addition, the content does not address any significant changes since national action plans and preparations will be lifted to regional level. Apart from this, regulations on natural gas sector remained untouched.[2]

The proposals under the latest package on the future operational model of electricity markets are based on the absolutely freely moving market prices, gradually liberalized renewable production, and more flexible demand response capabilities, while rejecting capacity markets in favour of the "purely energy market".

Helping to fulfil European climate policy for 2030, the winter package aims to harmonize the cooperation of stakeholders in a separate governance regulation. The proposal determines the competences and responsibilities shared by the European Commission and Member States in favour of completion of EU's energy and climate targets for 2030. The regulation obliges Member States to compile a long-term emission reduction strategy and an integrated national energy and climate plan. Furthermore, it contains provisions in case Member States'fail to meet EU targets.

Changes to directives on renewable energy production and energy efficiency seem fairly soft and moderate. Drafts fail to break down the 2030 EU targets to compulsory Member State level targets, but still the directive on energy efficiency extends the rule to an annual 1.5% increase up to 2030.

At the same time, support schemes of the various Member States have not been coordinated or integrated.

For such limited proposals, we might say that winter package is a lot of smoke with little fire. However, we must pay attention to the important fact that electricity sector is not only regulated by the above EU directives and regulations - rules on renewable production support schemes are set for instance by the guideline on state aids, and these went through considerable changes in 2015.

A similar change for electricity markets: the modification on power market regulations in 2009 delegated the tasks for preparation of network codes to ENTSOE. Major efforts were made to prepare these codes, and as a result, the market is now operated by effective and uniform rules approved by the European Union, starting from system operational and accession rules to the rules of day-ahead and futures markets.

1 Our article „Fourth energy package? Summer proposals on the modifications of energy market regulations" was published in Vol 3 2015 on the summer package of 2015 including the draft modifications of the directive on emission trade.
2 Our article on the first winter package was published in Vol 1 2016 with the title „European Commission's LNG, natural gas and security of supply vision".

Regulation on the establishment of Regional Operational Centres (ROCs) is an obvious step towards the regionalization of system operation, still a source of concern for several Member States. Indeed, this process has been underway since the establishment of ENTSOE, and will not end with the ratification of network codes: several questions are left open to be answered and solved in the next few years by ENTSOE. The regionalization and "unionization"of power market regulation does not start with the winter package, but it certainly will provide additional impetus.

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Energy market developments

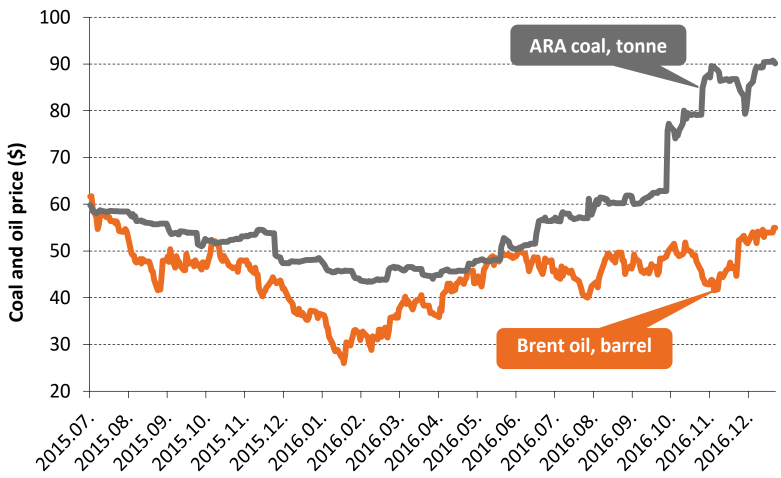
The last quarter of 2016 saw plummeting coal prices and a significant rise in oil prices in December caused by the decision of oil exporting countries to curtail their production. In addition to increasing energy carrier prices, European power prices were affected by considerable nuclear capacity cuts. This coupled with colder than average temperatures and European tight lower European LNG supply pushed up gas demand for power production purposes and increased prices. The Hungarian market premium was less affected by capacity cuts compared to the German market, with the spread declining in October-November until peaking consumption resulted in a significant rise in December prices. In December, the Hungarian-Austrian interconnector operated at full capacity mainly due to Ukraine's Western gas purchases. Although there was a perceivable rise in Russian import contract prices in the last quarter of 2016, the HUF's decline against the $ over the whole year, with low oil prices made Russian sources competitive, which was also reflected in growing Ukrainian imports to Hungary.

International price trends

Average ARA prices of October-December grew by nearly double the previous quarter's growth of more than 20%, accounting for 40% compared to July-September: coal prices nearly doubled over the last half year from 50 to 90 $/t. Year-to-year price increase caused by declining Chinese coal production capacities exceeded 60% in the last quarter of 2016 (Figure 1). The oil market was jolted by the announcement of the OPEC production cut at the end of November amounting to a daily 1.2 million barrels from 1 January under the condition that non-OPEC producers also commit themselves to a further reduction of 600,000 barrels, which they fulfilled. DThe 2% global production cuts, Brent oil prices increased by $10 to nearly 55 $/barrel by the end of December. Considering the quarter, oil prices grew by 13% year-to-year.

Asian LNG prices continued to rise after the third quarter's 30% rise in Japanese spot prices (in EUR), there was a further 30% increase in October-December on a quarterly basis (Figure 2). The Australian Gorgon-1 recommissioned in March stopped again at the end of November due to technical problems following an outage in April-June. Although Gorgon-2 started its operation in October, the third phase of the project was not realised contrary to the plans. Two other Australian projects, Prelude and Ichtys, also had delays. Since Australian producers have contracted to transport gas, these delays force them to buy contracted gas on spot market contributing to the increase in prices. Price increases also resulted from the effect of whether forecasts on irregularly cold winter in Asia and the stop of four South Korean nuclear power plants due to an earthquake in September.

Figure 1 Prices of month-ahead EEX ARA coal and Brent crude oil spot prices from July 2015 to December 2016



Source: CME, IEA

The quarterly average of day-ahead TTF prices in Q4 of more than 17 EUR/MWh hardly exceeded the quarterly average one year ago, but tripled the previous quarter's average. The price increase is explained by the cut of French nuclear capacities (see below), the increased demand triggered by the colder than average weather, and the low volume of LNG transports to Europe. The latter resulted from the diversion of Asian demand; October saw a year-to-year fall of 28% in LNG transported to Europe. Demand for spot sources was further increased by Great Britain's storage problems: although Rough, accounting for 70% of the country's total storage capacity, restarted operations in December following a five-month break, the operator had to further reduce the already cut withdrawal capacity.

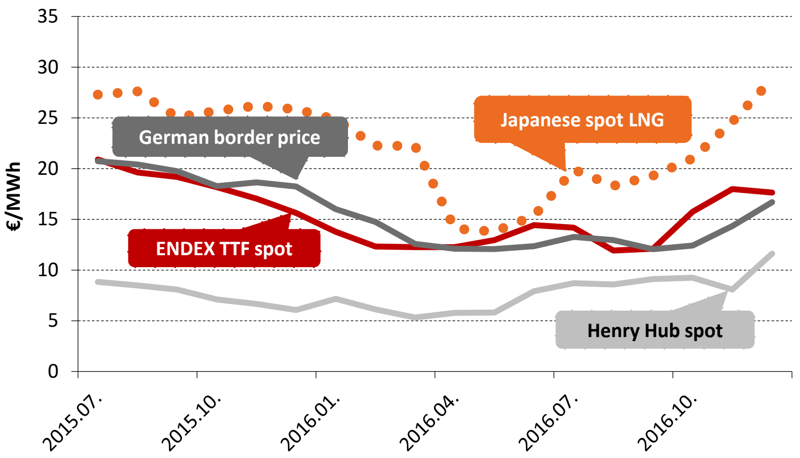
In Q4, contract prices of Russian import gas to Germany were below day-ahead TTF prices, making it more competitive. This phenomenon prevailed throughout the year: the 2016 average of German border prices remained below 13.5 EUR/MWh, while TTF approached 14

EUR/MWh on average. Due to these competitive prices, Russia broke a record by transporting 153 bcm gas to Europe, exceeding previous year's transport by 14%. Transmission on the Ukrainian-Slovakian interconnection was up by 29%, Nord Stream by 12% and the Ukrainian-Hungarian interconnection by 13%.

Nord Stream might be helped by the decision of the European Commission made at the end of October giving Gazprom permission to use more OPAL capacity. OPAL connects Nord Stream with Czech Republic, and for now Gazprom only has access to the half of the yearly 36 bcm capacity because of EU rules on third party access. In line with the Commission's decision, Gazprom has exclusive access to half of the capacity while the remaining 50% is accessible for all market players including Gazprom. Naftogaz says that with this rule, Ukraine would suffer a loss of a yearly 15 bcm transit. Based on the Polish PGNiG objection, with the European Court of Justice at the end of December, a German superior court suspended the Commission's decision. However, the high demand on OPAL was shown by the fact that the total January capacity was contracted on the auction held before suspension.

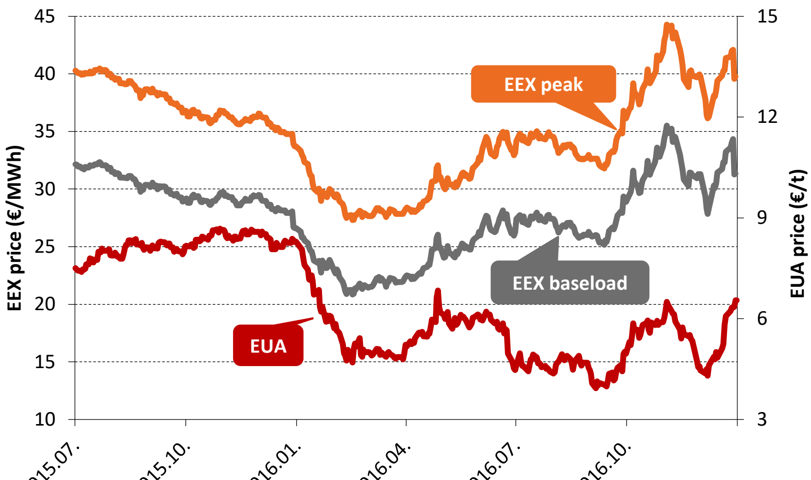
The quarter's European power market developments were primarily determined by the decision of the French nuclear authority in June on the exceptional security control of 18 reactors. In October the country's available nuclear capacity was 20% behind the same period of the previous year, and the uncertainties around restarting capacities pushed prices up both in November and December. Available nuclear capacities were also lower than usual in Germany, falling to 9 GW in December and hitting a historical winter low. The colder than average weather and the low supply led to prompt and short-term price spike. Reaching 250 EUR/MWh at the beginning of November, French week-ahead baseload prices broke a 15-year record.

Figure 2 Prices on select international gas markets from July 2015 to December 2016



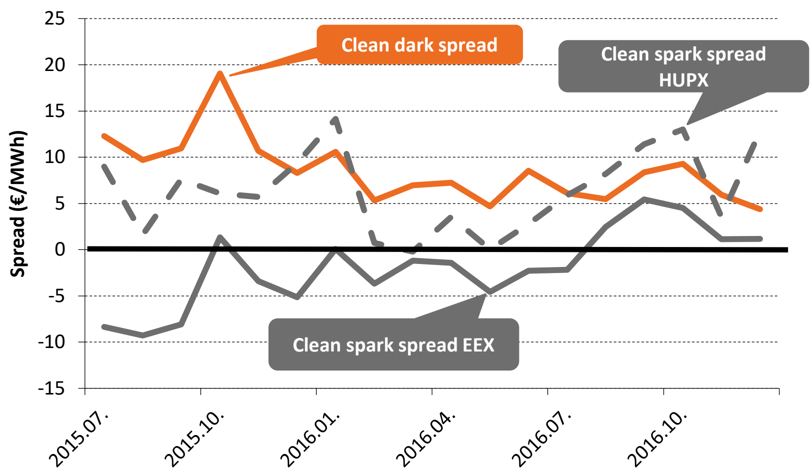
Source: Statistical Office of Japan, EIA, Gaspool, IMF

Figure 3 Prices of EEX year-ahead futures and CO2 allowances (EUA) with December delivery from July 2015 to December 2016



Soure: EEX, ICE

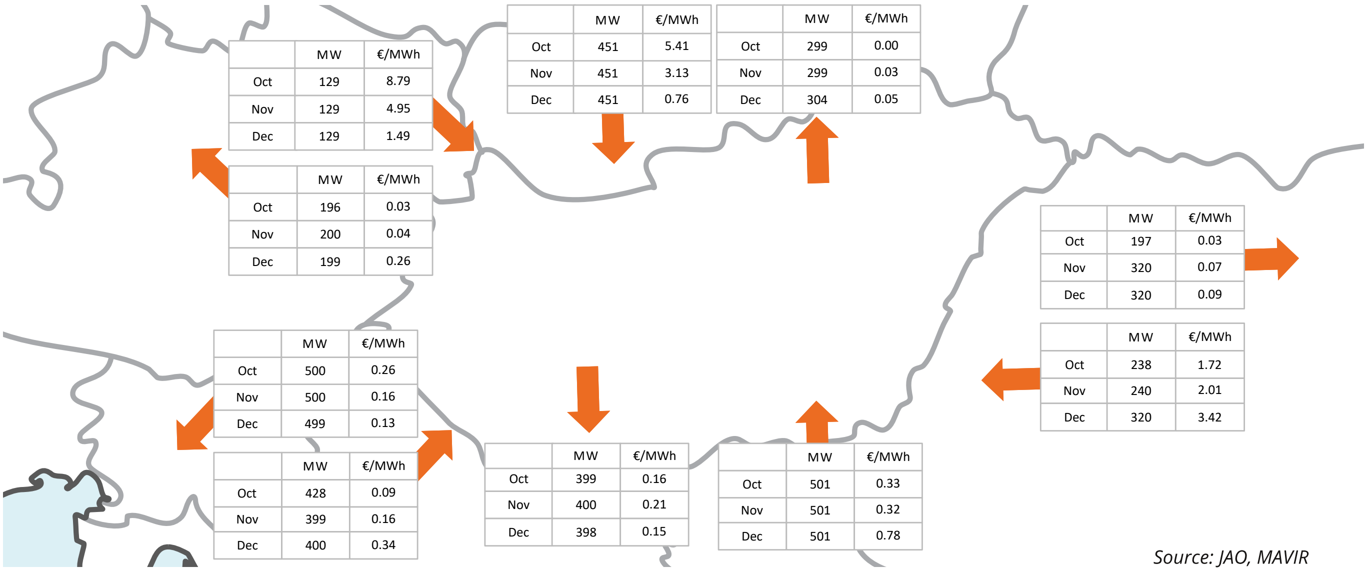
Figure 4 Clean spark spread (gas fired power plants) and clean dark spread (coal fired power plants) on German market from July 2015 to December 2016



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

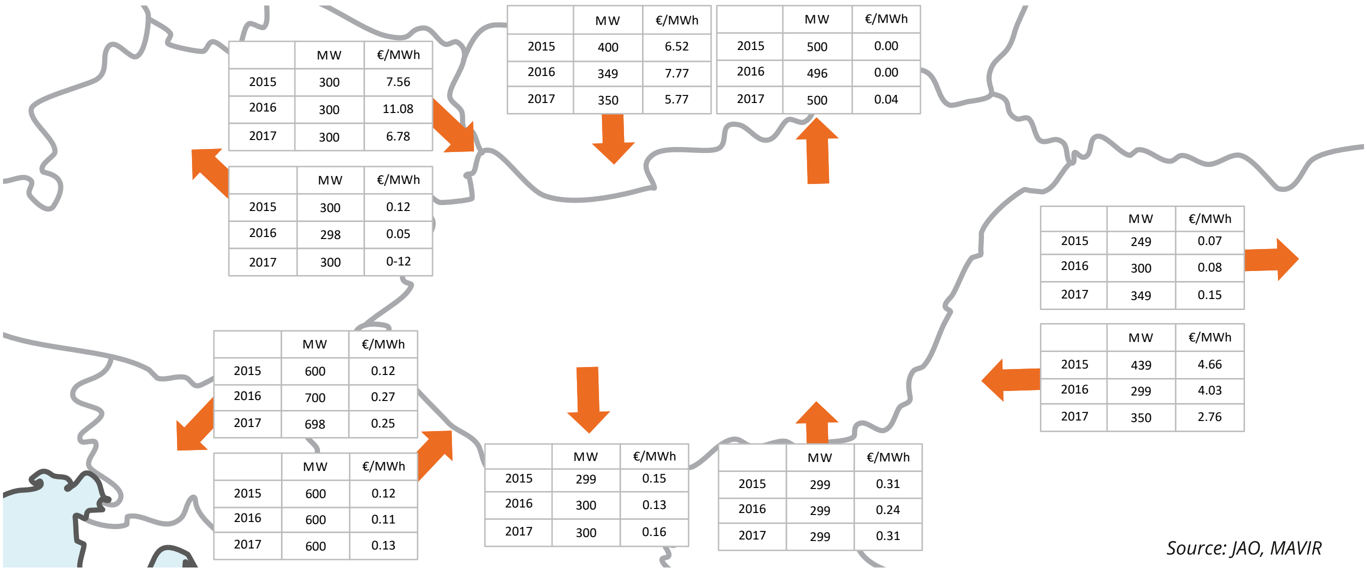
Note: Both indicators show the difference between electricity prices on exchanges and the cost of electricity generation, where the cost of production is added up by the cost of gas (spark spread) or coal (dark spread) needed for generating 1 MWh of electricity and the additional cost of CO^2 emission 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 ofthese 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, Q4 2016



Source: JAO, MAVIR

Figure 6 Results of yearly cross-border capacity auctions in Hungary, Q4 2016



Source: JAO, MAVIR

On the German power exchange, yearly baseload prices were up to 35 EUR/MWh at the beginning of November accounting for a more than 20% increase compared to the end of September (Figure 3). This was partly driven by the rise in coal prices and CO2 allowance prices; the latter rose by 26% in the same period in line with the market expectations about the decision of the Environment, Public Health and Food Safety Committee of the European Parliament backing the decision on emission allowances cuts after 2020. In the second half of November, coal and EUA prices fell, sinking German baseload future prices by more than 8 EUR/MWh to 28 EUR/MWh. This fall was followed by a rise in German baseload prices accounting for nearly 20% in Q4 compared to the previous quarter and 10% compared to the October-December average of 2015.

The clean spark spread remained positive as a result of increasing power prices, in spite of growing gas prices, while the clean dark spread was diminished by rising coal and EUA prices (Figure 4). The position of gas-fired power plants somewhat improved as a result of the declining average difference of the two spreads compared to the previous quarter. There was a spectaculous upswing in clean spark spread calculated on the basis of domestic electricity prices driven by the significant rise in Hungarian market prices in December (see next).

Overview of domestic power market

After low monthly import capacities on the Austrian border (19-29 MW) led to high auction prices in the third quarter (in August exceeding 11 EUR/MWh), in the fourth quarter the 129 MW import capacity resulted in a significant decline in prices (Figure 5).

Although prices of import capacities from Slovakia still exceeded 3.64 EUR/MWh in September – with a similar amount of offered capacity, prices did not even reach 1 EUR/MWh in December. Contrary to the Austrian and Slovakian borders, import capacity prices from Romania were continuously growing during the quarter despite growing capacity volumes, and unexpectedly, more than doubled the Austrian capacity prices in December.

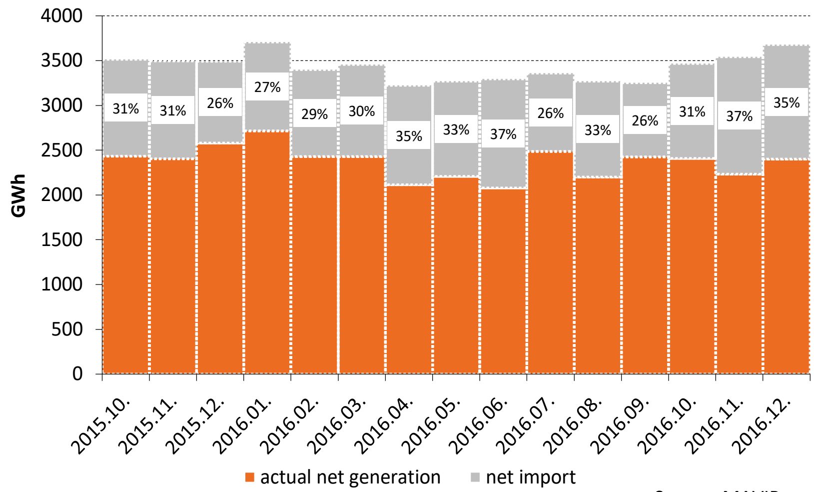
On the yearly auction, however, Austrian import capacities remained in high demand even though the 2016 baseload price, accounting for 6.78 EUR/MWh, lags far behind the 2015 prices that exceeded 11 EUR/MWh. Romanian import capacity prices fell by more than 30%, while Slovakian prices slid by 25% compared to the previous year, with the only growth found in Romanian sales volumes (Figure 6). This could explain the declining premium of the Hungarian market compared to the previous year: in the last quarter of 2015, the average Hungarian yearly baseload price was 8.3 EUR/MWh higher than in Slovakia and 4.2 EUR/MWh higher than in Romania, but the next year the average spread accounted only for 5 and 1.8 EUR/MWh, respectively (Figure 8).

In the last quarter the domestic electricity consumption rose by 2% as production fell 5% due to power plant maintenance. Consequently, the average quarterly import share grew from 29 to 34% (Figure 7). On a yearly basis, however – probably because of the better utilization of gas-fired power plants – domestic production grew by nearly 4%, and exceeded 28 TWh. Simultaneously, annual consumption remained stable, thus the annual average import share stabilized at 34% in 2015 and 31% in 2016.

The quarterly average of HUPX yearly baseload prices fell by 6% compared to the same period of 2015, while EEX grew by 10%. Consequently, the premium of HUPX almost halved to 6.2 EUR/MWh accounting for a 3-year low (Figure 8).

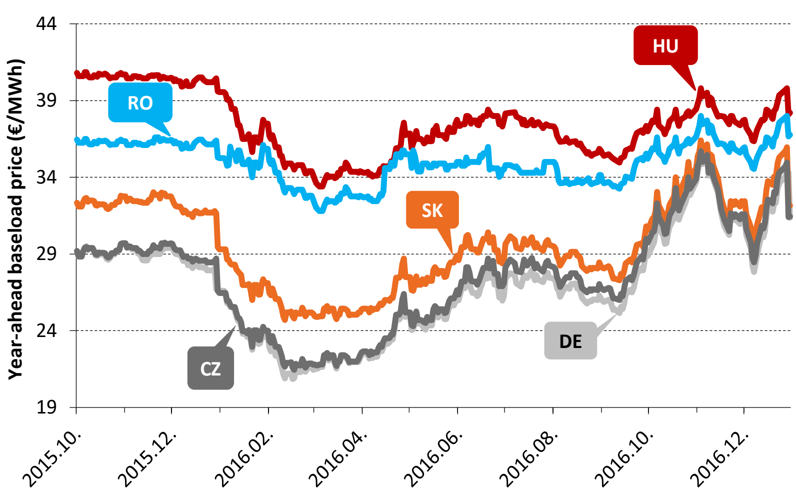
There was a rise in day-ahead HUPX prices at the beginning of October owing to the scheduled maintenance of Dunamente Power Plant (408 MW) and shortages in several smaller power plants. Although

Figure 7 Hungary's net electricity production and monthly net electricity imports between October 2015 and December 2016



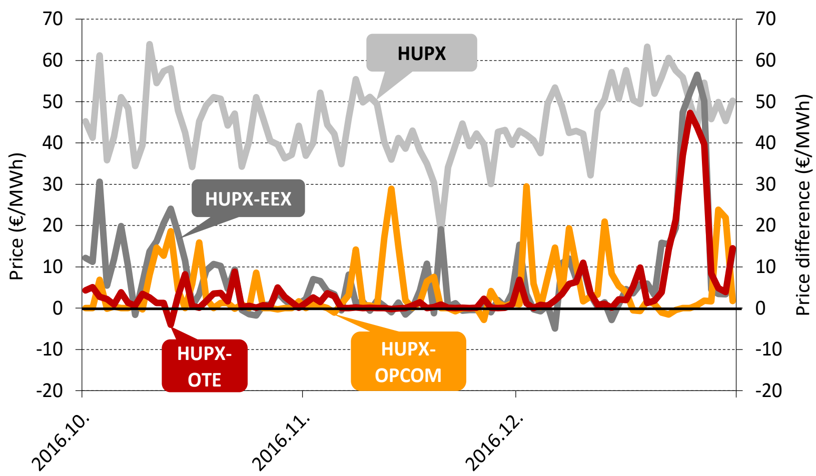
Source: MAVIR

Figure 8 Year-ahead baseload futures prices between October 2015 and December 2016



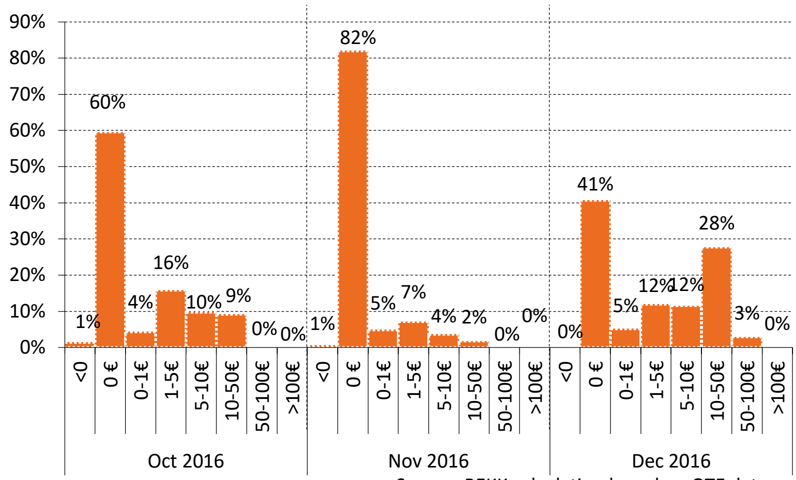
Source: EEX, PXE

Figure 9 Comparison of day-ahead baselaod prices on the EEX, OPCOM, OTE and HUPX exchanges between October and December 2016



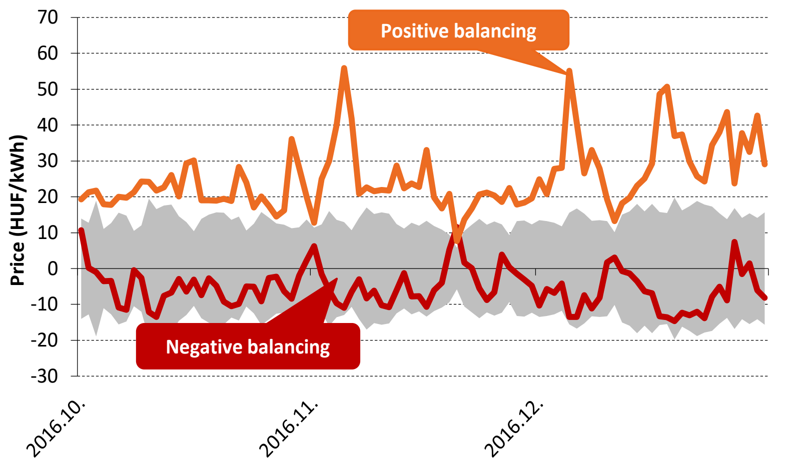
Source: EEX, OPCOM, OTE, HUPX

Figure 10 Frequency of various price differences between the Hungarian and the Czech exchanges between October and December 2016



Source: REKK calculation based on OTE data

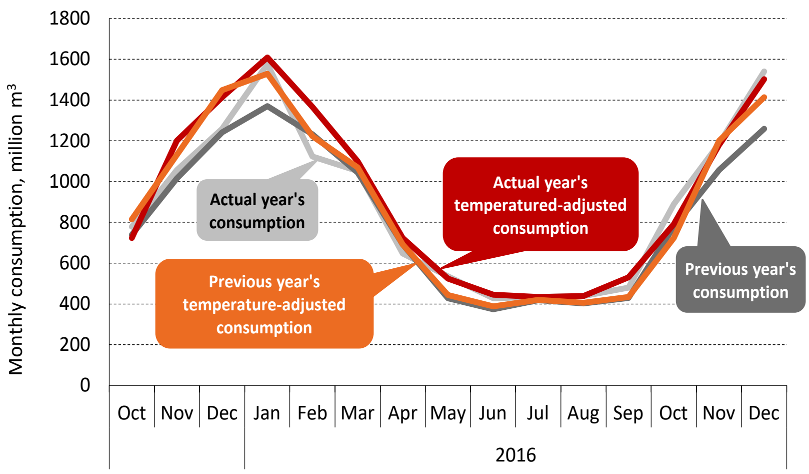
Figure 11 Daily average of balancing prices and spot HUPX prices, Q4 2016



Source: MAVIR, HUPX

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

Figure 12 Raw and temperature-adjusted monthly gas consumption between October 2015 and December 2016 compared with the previous year



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

maintenance works of a Paks Nuclear Power Plant block starting in the second half of October and lasting until the end of the year, this production was replaced by imports without a significant rise in prices. In the last week of October there were several instances when day-ahead HUPX prices were lower than EEX day-ahead prices (Figure 9). In December, HUPX prices were pushed up by the peaking demand triggered by cold weather and lighting for festive decorations; the load at the beginning of December, 6749 (net 6300) MW, broke the consumption record (November 2007). As a result, the average December HUPX/EEX spread approached 12 EUR/MWh compared to 2.4 EUR/MWh in November.

The alignment of the Hungarian and the Czech day-ahead markets was stronger than in Q3, with no difference in 82% of the hours in November (Figure 10). However, the price increase in December seemingly separated the two markets, when the difference between Hungarian and Czech prices were at least 5 EUR in over 40% of the hours, and a spread exceeding 50 EUR occurred as well. Even the most aligned Romanian market was significantly cheaper than HUPX in December, exceeding 10 EUR/MWh in 25% of the hours.

Exchange prices largely determine the costs of the deviation from the schedule, since the system charges for balancing developed by MAVIR provide 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 fourth quarter, the average price of positive balancing exceeded 25 HUF/kWh, more than the average of the third quarter of 2016 accounting for 19 HUF/kWh. The quarterly average was lifted by peaking prices in December from the high demand (Figure 11).

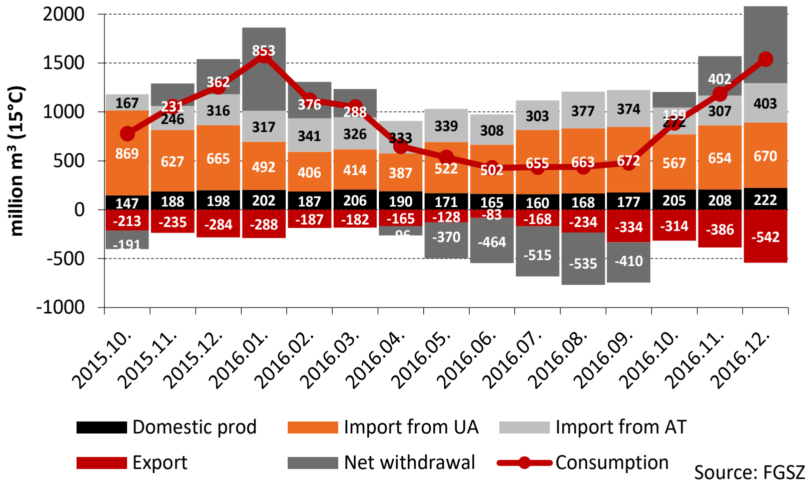
Overview of domestic gas market

The consumption over the last quarter of 2016 reached 3.6 bcm, exceeding the consumption over the same period last year by 0.5 bcm. The increase is primarily attributable to the cold weather, even though temperature adjusted data show a 100 mcm year-on-year growth (Figure 12).

Domestic production increased nearly 20% year-on-year, covering 18% of domestic consumption, close to the period in 2015 (Figure 13). On a yearly basis, domestic production grew by 140 mcm (to 2.26 bcm) compared to 2015. However, there was growth in yearly natural gas consumption of more than 10.3 bcm in 2016 compared to 9.5 bcm in 2015 according to gas flow data of FGSZ, the Hungarian gas transmission company. The most spectaculous change in sourcing over the last quarter of 2016 year-on-year was the greater role of gas storage as withdrawal more than tripled to cover the increased consumption. There were hardly any changes in the total quarterly volume of imports, but imports from Austria grew by 35% and displaced Ukrainian imports. The 70% year-on-year growth in Hungarian exports indicates Hungary's expanding transit role.

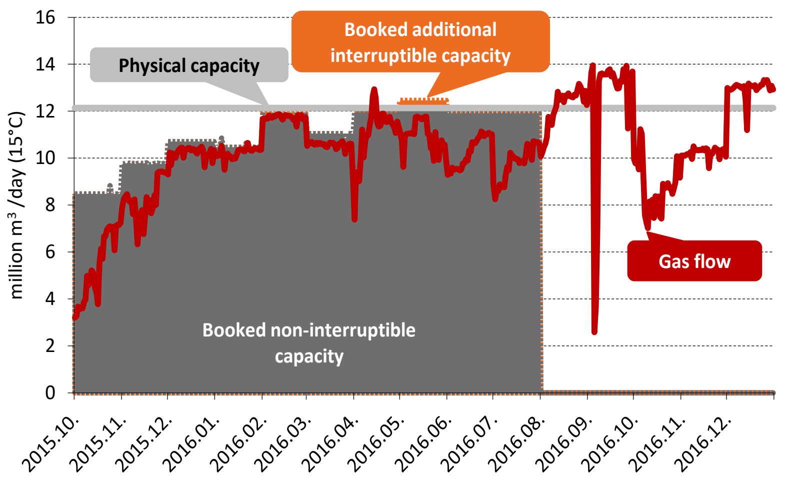
Trade on the Mosonmagyaróvár entry point grew continuously in the quarter, and the December average utilization exceeded the technical capacity of the pipeline (Figure 14). This phenomenon closely correlates with the strengthening transit role of Hungary, since traders contracted capacities on the Austrian-Hungarian interconnection primarily for supplying Ukraine. German border prices of Russian gas below TTF prices and the growing volume of gas coming to Europe through the Nord Stream suggest that it was profitable for traders to purchase Russian gas on Western markets and transport it to Ukraine through Hungary and Slovakia. High demand also led to a in capacity prices: the clearing price of the monthly capacity auction announced for December exceeded the starting price by 13%.

Figure 13 Source structure of Hungarian gas market by month between October 2015 and December 2016



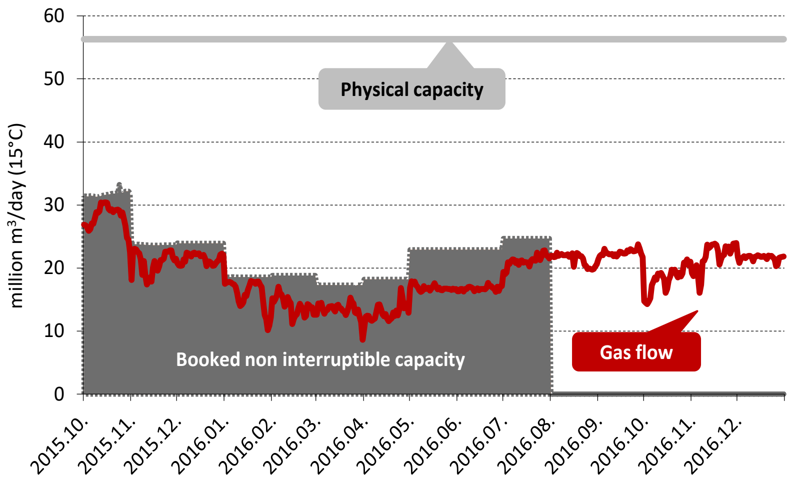
Source: FGSZ

Figure 14 Transmission at the Mosonmagyaróvár (Austrian border) entry point between October 2015 and December 2016 together with booked interruptible and non-interruptible capacities



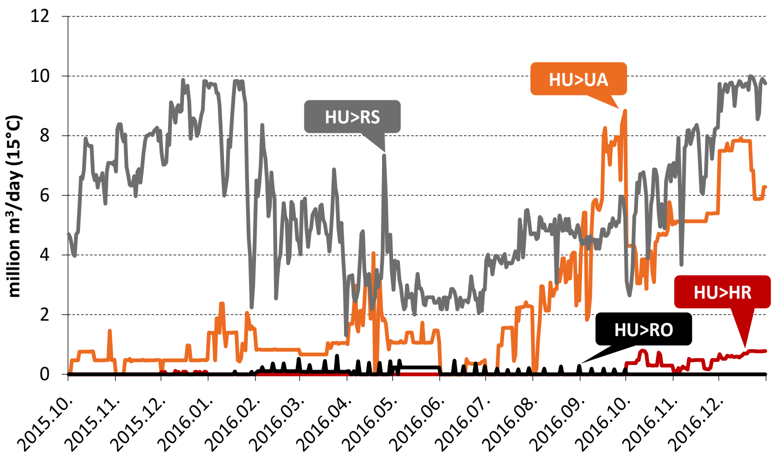
Source: FGSZ

Figure 15 Transmission at the Beregdaróc (Ukrainian border) entry point between October 2015 and December 2016, together with booked interruptible and non-interruptible capacities



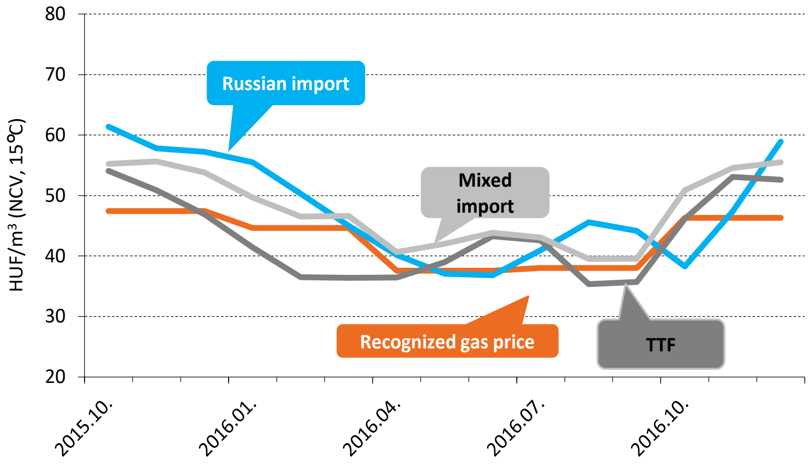
Source: FGSZ

Figure 16 Hungary's natural gas exports to Ukraine, Croatia, Romania and Serbia from October 2015 to December 2016



Source: FGSZ

Figure 17 Recognised natural gas selling price of universal service providers and elements of the gas price formula between October 2015 and December 2016



Source: REKK calculations based on EIA, Gaspool and Eurostat data

Note: Russian import prices are calculated from Eurostat monthly data and converted to HUF at a market exchange rate. TTF price is a monthly average calculated from daily day-ahead prices converted into HUF at a market exchange rate. Recognised natural gas price is a price estimated on the basis of KHEM decree 29/2009. Mixed import price contains 60% oil linked price estimated on the basis of the decree and 40% TTF price. It differs from the recognised natural gas price not only in the weighthing of spot and oil linked price but also in the reference time period and the applied USD and EUR exchange rates, since spot prices determined by the decree are the averages of TTF future prices for the actual quarter quoted in the period from the 1 st until the 15th day of the 2nd month of the quarter prior to the actual quarter, and are calculated at a non-market based USD and EUR exchange rate.

The 38% utilization of Beregdaróc entry point in December was under the November utilization level (Figure 15). Similarly, the 37% average utilization in Q4 42% less than the same period of the previous year. On a yearly basis, however, the positive effect of declining oil prices on the competitiveness of Russian long-term import contracts can be clearly tracked with Ukrainian imports growing from 5.8 bcm in 2015 to 6.6 bcm in 2016 (these figures include transit gas to Serbia and Bosnia-Herzegovina).

Of the 41% growth in exports year-on-year, 70% in Q4 left Hungary for Ukraine. This export volume totalling 510 mcm was a big jump compared to the previous year's 44 mcm. It is attributable to the fact that Ukraine has not purchased gas from Russia since November 2015, but has met its total demand from Western transit. Although exports to Serbia were almost equal to 2015 exports, its share of exports declined from 94% in 2015 to 55% in 2016. The remaining 4% of Hungarian exports went to Croatia (Figure 16)

Figure 17 shows Russian import prices in Q4 rising significantly by more than 10% compared to Q3. The influence of the weakening HUF/$ exchange rate was likely greater than the moderate shift in the average oil prices of the preceding 9 months with Q4 taken as a basis for the price function of long-term contracts: the average HUF/$ exchange rate of Q4 approached 287 (296 in December) compared to 279 HUF/$ in Q3. With a 20% rise in spot TTF prices, both oil-linked import and mixed import prices including spot sources were up and – in REKK's estimation – exceeded the recognised purchase costs of universal service providers by more than 8% in December. On a yearly basis, however, Russian import prices fell significantly from 66 HUF/cm in 2015 to 45 HUF/cm.

Power market model

One of the most important elements of the winter package is the proposal for the modification of the regulation on reforms of electricity markets. While referred to as the new market model, it is essentially no different from the current European model: promoting energy only markets and rejecting capacity, a philosophy still contrary to the current practice of several EU Member States using capacity mechanisms for supply security considerations.

A key issue for European energy markets is whether the market model based purely on price signals is sustainable with the growing penetration of weather-responsive renewable capacities, or if capacity markets are needed to facilitate new power plant projects serving back-up for security of supply purposes. At the same time it is uncertain whether demand side mechanisms are sufficient to balance the fluctuation of wind and PV capacity production, or low-utilitization reserve capacities are needed.

The current proposal asserts that truly open, unregulated energy markets provide sufficient price signals to power plant investors and demand side flexibility obviates the establishment of new reserve capacities serving exclusively for balancing. In the Commission's opinion, capacity markets are not only unnecessary but also have a distorting effect, weakening the integration of European energy markets on the one hand and smoothing price peaks that deprive energy markets of their genuine abilities to encourage investments and control demand.

Nonetheless, belief in the righteousness of pure price signals not nearly as widespread as official publications would suggest. The Commission cannot and would not presume to assume Member States' responsibility for security of electricity supply. Therefore the modification proposal dedicates 5 pages to new rules and conditions for capacity mechanisms. Controversies around capacity markets are not unique: the new power market model follows the dichotomy of the maxim „Trust in God and keep your powder dry".

Operation of electricity markets

The revamped electricity market model is based on the modification of four currently effective EU regulations accompanied by several impact analyses and reports. First, we will have a closer look at the proposal on the modification of the regulation of operational rules of electricity wholesale markets, which is at the heart of the package[1].

In its preamble, the decree clearly states that electricity market regulations must be modified to enable integration and growth of power markets , specifically weather-dependent renewable generation capacities. The 29% share of renewables in power generation is expected to grow to 50% by 2030, gradually phasing out fairly generous feed-in obligations forcing producers to sell their electricity on market and to compete on an even playing field. The market integration of such a huge quantity of intermittent power generation requires much more flexible electricity systems.

For one, flexibility may be interpreted as allowing close to real-time sales of low quantities of power produced, for instance, by small household power plants. The deadline for trade and schedule modification should be approached in real time, which would allow for an hour-ahead selling option on intraday markets. Meanwhile integration of intraday markets is critical to enable quick marketing of huge volumes of renewable generation and quick purchase of missing volumes on liquid markets.

Massive renewable production, however, will encumber the balancing of the system even with liquid spot markets. Therefore the Commission urges a closer integration of reserve markets going beyond the inter-TSO trade of balancing energy. Proposals so far have not questioned the right of TSOs to independently set and contract reserve capacities to be contracted within a given balancing zone, but this goes further:it would optimise the

1 2016/0379 (COD) Proposal for a Regulation of the European Parliament and of the Council on the internal market for electricity (recast). The proposal is a significantly rewritten and completed version of 714/2009/EC Degree practically to be considered a new legislation volume of reserve capacities to be contracted on a regional level, and would provide for the contracting of the balancing capacity in regional framework instead of the current national balancing zones.

The integration of renewable generation requires not only the adjustment of market regulation but also producers will have to relinquish the benefits of priority dispatch. In the future, only generating capacities using renewable energy sources and cogeneration with an installed capacity of less than 500 kW would be subject to priority dispatch. Should the share of capacities under feed-in obligation reach 15% within the power plant up to 2026, the capacity limit of eligibility will drop to 250 kW.

Similarly, balancing responsibility will extend to all renewable-based and co-generation power plants exceeding 500 kW, and the capacity threshold will decline to 250 kW from 2026. This would end the current misalignment whereby the burden of balancing responsibility is placed on conventional power plants and renewable capacities can freely deviate from the submitted schedule.

Simultaneously, the freedom of TSOs in curtailment and redispatching would be constrained. Power plant capacities redispatched upward or downward with reference to congestions would be selected on a market basis (by auctioning) in the future. Where non-market based curtailment or redispatching is used, power plants would be subject to compensation of up to 90% of the additional costs caused by the curtailment or redispatching or revenues not earned because of the curtailment or redispatching.

Curtailments or redispatching from congestions and compensations primarily apply to newly connected renewable power plants, which would impose a significant investment costs on network companies responsible for connecting renewable capacities. The proposal allows distribution and transmission companies to calculate with curtailment or redispatching accounting for a maximum of 5% of installed capacities using renewable and co-generation capacities in network planning.

However, the proposal fails to facilitate network developments in general. In addition to the incentive by compensations, only the provision on the compulsory reinvestment of revenues deriving from the auction of interconnection capacities can be considered to be such an incentive. Meanwhile, the effective enforcement of the latter provision is dubious because the text in the provision says that the reinvestment of auction revenues may also be accounted as maintenance costs.

The Commission has been trying unsuccessfully for years to remedy shortcomings that are setting back interconnection capacity developments. Neither exemption rules, nor the inclusion of ACER in debated developments, nor special licensing rules on electricity transmission infrastructure of common interest could remedy the incentive deficiencies. While the Commission's supplemental documents estimate investment needs of transmission networks to be140 billion EUR for the period between 2012 and 2020[2], nobody has answered the question who will make these investments.

Therefore, the proposed provision for a bidding zone review and authorizing the Commission to make modifications is a significant step forward for releasing transmission network congestions. Bidding zones, including structural congestions, shall be divided into two (or more) bidding zones along congestions with interzonal capacity auctions on the borders of the zones. This provides a clear signal to the relevant TSO to make investments for needed developments.

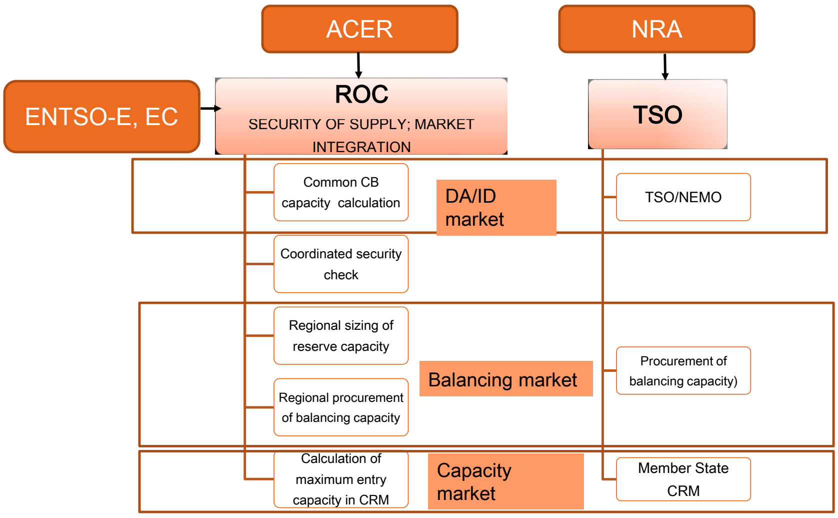
This provision has particular significance for Central Europe since it projects the breakup of the Austrian-German bidding zone, and may also lead to the dissolution of the uniform German price zone, which would help to manage loop flows that have caused serious problems for transmission networks in the region[3].

From the perspective of network operation, the provision on the obligation of TSOs to establish regional operation centres (ROCs) can be considered a considerable departure from the traditional business model. ACER created the system operation regions based on the proposal of ENTSO-E taking into consideration the grid topology and borders of capacity calculation regions defined in the CACM decree. Hungary's region is likely to match the current CEE region (Germany, Poland, Czech Republic, Austria, Slovakia, Hungary, Romania, Slovenia and Croatia).

2 SEC(2011) 1234 final COMMISSION STAFF WORKING PAPER Executive Summary of Impact Assessment Accompanying the document REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on guidelines for the implementation of European energy infrastructure priorities repealing Decision No 1364/2006/EC
3 See more details on loop flows in our Article „A hurok szorításában" in Volume I of our Market Report 2016.

Theoretically, ROCs will perform the functions of regional relevance including capacity allocation tasks (creation of common system models, coordinated capacity calculation and coordinated security analysis), facilitating the integration of reserve markets (regional sizing and procurement of reserve capacity), tasks related to short-term security of supply (seasonal adequacy outlooks, analyses to crisis scenarios), and functions related to capacity markets (evaluate the maximum import capacity available for the participation of foreign power plants in capacity mechanisms).

Figure 1: Planned responsibilities and competences of ROCs



This raises several questions with respect to the responsibilities of ROCs and their relationship with Member States' TSOs that are not answered by the proposal. The operation of ROCs would be managed through a cooperative decision-making body representing the TSOs of the region, which infers that ROCs would be an institutionalized form of the cooperation amopngst TSOs. Although the relevant EU legislation provides that TSOs of Member States are responsible for the establishment of ROCs, ROCs would have independent and trans-TSO decision-making authority in several functions defined in the proposal. The following section highlights this controversy: „Regional operational centres shall provide transmission operators of the system operation region with all the information necessary to implement the decisions and recommendations proposed by the regional operational centres."

The proposal also includes considerable changes related to the operation and responsibilities of ENTSOE. ENTSOE generally defined as the „network" of European TSOs, should act „independent from individual national interests or the national interests of transmission system operators" serving climate protection objectives in accordance with the proposal. The draft also refers to the possible redrafting of the statutes of the organization.

ENTSOE so far was responsible primarily for the development of Network Codes as well as the coordination of 10-year network development plans and capacity adequacy outlook. This circle of functions would be extended further a newly created task: ENTSOE would be responsible for making all the rules of Member States' CRMs and for making resource adequacy assessments enabling (or hindering (!)) the introduction of CRM. ENTSOE would be responsible for adopting an operational framework for ROCs strengthening the image of top-down cooperation.

Simultaneously, the proposal gradually extends competences of the Commission and ACER. The Commission would gain statutory power on several areas of cross-border trade and would be able to adopt delegated acts. One of the most important statutory powers is in defining the borders of bidding zones (price zones). Its statutory power, however, does not include rules on market-based procurement for ancillary services that are outside of frequency controlling purposes, demand responses (aggregation; storage; curtailment of consumption) or extension of CACM to the curtailment of producers and customers and redispatching.

ACER competences are meant to grow in parallel, even if ACER is not supposed to grow into a European regulatory authority. The key responsibility area of ACER would continue to focus on cross-border electricity trade and market monitoring. Its oversight competencies would include the definition of ROCs and adoption of rules on capacity markets elaborated by ENTSO.

Capacity markets

Provisions on CRM may be the most ambiguous part of the proposal. While the Commission states that the establishment of CRMs is unnecessary and in fact harmful to energy markets, the draft dedicates nearly 5 pages to the topic. This duality is reminiscent of the regulation on unbundling from the last directive which went into detail on the rules for countries opposing ownership unbundling and applying the ITO model with the clear intent to create flexibility for TSO's that were not prepared to fully unbundle according to a single rule.

One of the most common arguments against capacity markets is the distorting effect of state aid granted to power plants. Therefore the draft includes strong guarantees to for Member States to access the capacity of neighbouring countries using interconnections to ensure power plant capacities.

The Commission's primary concern here is that capacity markets and the continuous availability of contracted capacities restrict price volatility and thus reduce demand response and the supply of other flexibility services. In this system, power plant capacities eligible for capacity payment – typically fossil-based power plants – would gain a competitive advantage compared to renewable power plants unable to provide such services, which would lead to increasing costs for renewable support schemes and push down prices of electricity products.

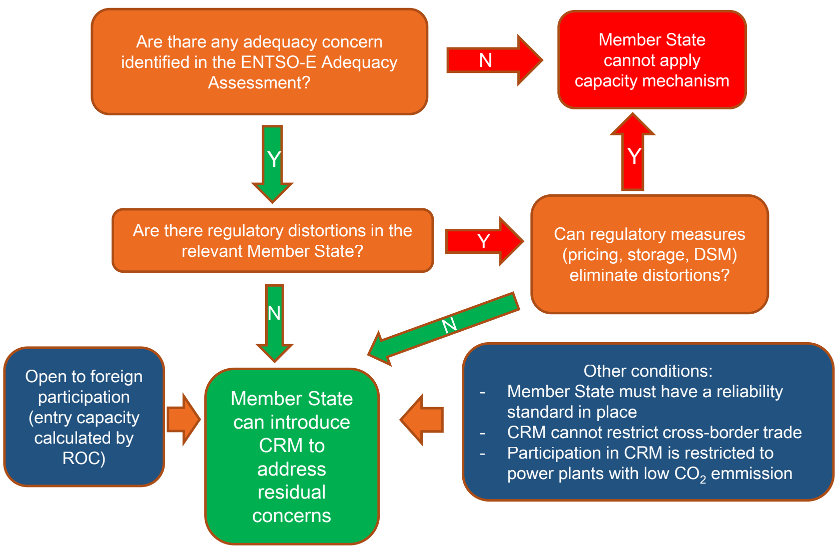
Justifiably, countries opposing capacity markets building significant renewable capacities fear that the effect of CO2 allowances that erode the competitiveness of coal-fired power plants would decline if they could successfully receive compensation on capacity markets. In a broader sense this would also weaken efforts towards decarbonising the power sector and limit the market potential of national generation. Germany opposes the introduction of capacity market, yet it grants capacity payments to most of its lignite-fired power plant blocks. To remedy this conundrum the draft proposes to set an emission ceiling (550 gr CO2/kWh) for power plants taking part in capacity mechanism, which essentially excludes coal-fired blocks from CRM.

The draft sets very strict criteria for a Member State bring capacity mechanisms into force siting supply security concerns. The draft requires long-term capacity adequacy assessments to decide on the need for CRM, and this would shift from the competency of Member States to ENTSOE. If the assessment concludes that, in an observed duration, significant deterioration of the supply security index is not expected, the given Member State cannot open a CRM, and if one is in operation it must suspend it. In this sense, Member States would lose their right to independently determine the necessity of the introduction of capacity mechanism. However, Member States will maintain the right to set the level of security of supply that is provided for their citizens. If the ENTSOE assessment concludes that unsupplied hours exceeds the cap defined by the Member State, the Member State can introduce capacity mechanism.

Nonetheless, the draft defines very strict rules on the application of CRM distribution functions and legal competences among ENTSOE, ACER, ROC, the TSO of the given Member State and TSOs of neighbouring countries. ENTSOE (with ACER oversight) is responsible for elaborating and approving the methodology of resource adequacy assessment, conducting analyses for the given Member States, defining power plant eligibility criteria and setting fines to be imposed on non-compliance of power plants. The ROC is responsible for calculating the maximum entry capacity available for the participation of external capacity taking into account the expected availability of interconnection. Member States will define a reliability standard (based on the methodology elaborated by ENTSOE) and the amount of capacity to be procured in the mechanism, while neighbouring TSOs will be responsible for the registration of eligible generation capacities and carrying out availability checks.

Another important issue for countries considering the introduction of capacity mechanisms is that those who are about to apply CRM immediately after the entry into force of legislation (after 2020) in line with the proposed procedure must make calculations with a relatively long lead time. The elaboration and approval of the above methodologies and Member States' resource adequacy assessments are likely to take years. In addition, state aid has to be approved by DG COMP, which took two years in the British and French CRM cases. Taking this into account, it is unlikely if possible at all to introduce any capacity mechanisms between 2020 and 2025, when procedures are still unknown.

Figure 2 Capacity mechanisms



Role of customers - Directive

The power market model proposed by the Commission, however, is not built on reserve capacities provided in the framework of CRMs, but on market prices and demand response. The proposal would remove caps on market pricing: minimum price could be set at a value of minus 2000 €/MWh while maximum price could be set at the value of VOLL (value of lost load).

Free market prices increase supply side response, since high prices are an incentive to commission even the most expensive generation units in times of shortage, while generation units are penalized with low prices in situations of oversupply. Therefore it gives an impetus to peak power plant projects and to storage developments that considerably increasing the flexibility of the generation side.

Supply response itself, however, cannot provide for the power network balance: the other side of the proposed market model is demand response, which is based on real-time electricity price signals to customers. Therefore, the Commission would cancel price regulation, and oblige suppliers to offer customers dynamic electricity pricing contracts more effectively reflecting the real time value of electricity.

The proposal would allow for a 5-year temporary period with regulated prices maintained for vulnerable customers, while non-vulnerable households face market prices from the entry into force of the directive. The Commission does not differentiate between the various forms of price regulation, which could lead to additional controversial situations: while it would qualify regulated prices linked to wholesale prices as illegal, it probably would not oppose „market pricing" – which is often completely independent from market price movements.

Dynamic or real-time pricing that triggers demand response, however, is conditional on a proper smart metering system. The proposal provides that customers should have the possibility to opt for such a system, but does not include any more conditions and requirements. It does not oblige Member States to equip/deploy customers with smart metering systems; it only obliges them to base their decision on a cost-benefit analysis and repeat it year by year if results are negative in a given year.

Most customers, however, do not have high-capacity and controllable devices such as electronic vehicles or heat pumps. Therefore the proposal facilitates the market entry to aggregators, groups of a large number of customers with access to organised energy markets (DAM/ID/reserve market) to trade their flexibility and self-generated electricity. The proposal also encourages the establishment of local energy communities: these are non-profit organisations (associations, cooperatives etc.) operating a small energy system and organising the energy supply of customers and producers within a geographically confined community network. Similar to aggregators, community energy could participate in power markets, which would certainly require the modification of commercial codes.

The proposal looks at these provisions as means of consumer empowerment by allowing customers to participate in market and find savings from price changes. In the end, the proposal seeks to maximize demand side flexibility and use it to balance the system.

Renewable energy

The Winter Package[1] pays special attention to renewable energy since it is one of the main forms of „clean energy deserved by all Europeans". It is a proposal that will amend the 2009 Renewable Directive, adding more layers to the existing regulations that oversee the functioning of the electricity market, and specifically network integration of renewable energy generation.

The revised Renewable Directive seeks to secure the 2030 EU renewable target of 27% as a ratio of gross final energy consumption, recognising that current measures are only forecasted to reach a ratio of 24.3%.[2] Annual renewable investment has declined by 60% since 2011, an outcome of lower investment and falling costs, while the environmental impact of fossil fuels is still not internalised in the cost of electricity generation. It is notable that the Winter Package recognizes and supports renewable based heat generation, which has been under the competency of member states, primarily by reducing barriers of access to district heating infrastructure. In addition to network integration, the most important question for electricity generation is whether renewable capacities can compete in the market without support. Their integration into the electricity market and the intensification of climate policy regulation will likely make it possible to cease the support of mature technologies by 2030, but in the meantime market based investments will be uncertain because of surplus capacities, low CO2 allowance prices, stagnating wholesale electricity prices and the relatively high costs of renewable technologies.

Multiple elements of the plan intend to support cost efficiency. On the one hand this can be interpreted among the sectors: neither the current nor the predicted future share of the cooling/heating sector – which offers substantial growth opportunities for renewable energy use – are in harmony with cost efficient decarbonisation goals (as an example, there is combined auctioning of heat and electricity in the Dutch renewable auctions)[3]. On the other hand, it can also be interpreted among countries, since the member states have differing renewable potential and capital, connection and administrative costs. Within the continuum between the economic advantages of a uniform European renewable support scheme and the sovereignty of the member states, the proposal takes (another) step toward the former. Moreover, the cost-efficient design of the support schemes is especially important. The regulations in several member states systems did not consider the declining cost of technologies, promising excessive support that resulted in financial and political turmoil, and greater uncertainty is incorporated into investment costs.

Let's review the actual recommendations of the draft Directive concerning the three sectors!

Electricity

As already mentioned, within the package of proposals the question of electricity market and network of electricity is guided not by the renewable directive but by the regulations on the operation of the electricity market. From within the renewable directive, we would like to highlight four important questions: principles and regionalisation of support schemes, options to reduce capital costs, and lowering administrative barriers.

The evolution of support schemes is nothing new; the 2014 Guideline on state aid (2014/C 200/01) provides a detailed description of the expectations on the support to renewable electricity (most of all, the obligation to competitively allocate support) and most member states have already started to reform their support systems. In order to increase investor certainty, the new Directive also contains the principles of support systems, supplementing the Guideline and the future case law of DG Competition. Here the retroactive amendment of support schemes is explicitly banned (articles 4 and 5) to reduce regulatory risks. Member states must review their support schemes every four years (article 4), and based on this decide on the future of the scheme. Predictability is greatly improved through the obligation of member states to announce the allocation method for renewable support three years in advance, including the timing of auctions and the capacity and budgetary limits of support (article 15). The member state cannot lower the announced value, it can only set higher limits.

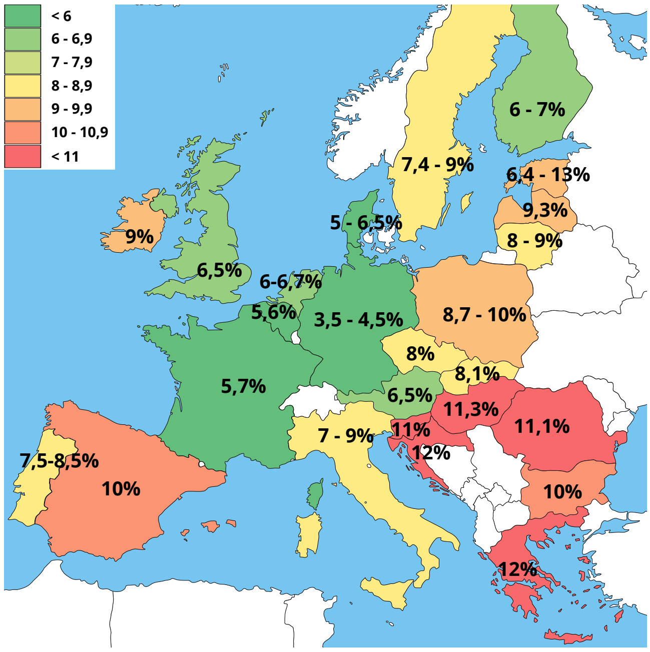
1 http://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition
2 Impact assessment of the Renewable Directive (SWD(2016) 418 final)
3 We covered the experience on renewable auctions in more detail in Issue 2 of our 2015 Volume: "Renewable auctions: questions and experience"

The larger the geographical area covered by a given support scheme, the more likely it is that the projects with the lowest cost will be implemented, therefore the same production/capacity level (EU target) is achieved at a lower cost. According to analyses quoted by the impact assessment of the Directive, a common Scandinavian quota system would save EUR 680 million between 2015 and 2020, while a common premium system for AT/CZ/HU/SK would reduce costs in the same period by EUR 325 million. Already the 2009 Directive allowed the coupling of support schemes for common projects and support schemes through statistical transfer or the import of renewable energy from outside the EU. Except for a few instances, member states have not really taken advantage of these opportunities, since most of them fulfil their 2020 targets through domestic projects without any major effort. Possibly at the end of the period the few countries (e.g. the Netherland) with uncertain performance may look to cooperative solutions. The current proposal goes further and prescribes as gradual obligatory opening of member state support schemes. According to the proposal, installations in other member states can also bid for at least 10% of new supported capacities between 2021 and 2025, and at least 15% between 2026 and 2030 (article 5). In 2025, the Commission may increase these ratios further.

The question of differing cost of capital among EU countries was not addressed in the official Commission documents, and although an EU measure dealing with differences in capital cost is not part of the Directive the impact assessment pays close attention to it. The cost level and support need of renewable investments is greatly influenced by capital cost – which varies substantially across member states.

The capital cost depends on the risk profile of the country, the sector and the technology in question. The production cost of a photovoltaic investment is calculated below for three countries with different costs of capital. The table (1) illustrates that the levelised cost of electricity (LCOE) and the need for support is the lowest in the country with the lowest number of sunny hours, thus the cost of capital is a more important factor than the technological potential.

Figure 1 The capital cost of onshore wind power plants, 2015



Source: DIACORE

The reduction of costs or regrouping of investments toward low-cost countries (e.g. through opening up the support schemes) result in declining EU level costs. Shepherding renewable investments toward a few countries with low cost of capital is constrained by network capacities and the shortage of potential sites.

The impact assessment outlines two options to handle differing costs of capital: either countries or technologies with higher cost of capital could obtain some EU level support. The draft legislation, however, does not contain an actual proposal to manage this problem.

Obtaining a permit for renewable energy projects is still an important impediment to (or an additional cost item of) investments that differs across member states. The Directive articulates specific requirements as opposed to what were general principles. On the one hand, from 2021 the so called one-stop shop administration has to be introduced. In other words, all permits necessary for the realisation of the investment and the launch of production (including permits for the production unit as well as the connecting network infrastructure) can be acquired in one location (articles 16 and 17). It is the task of the designated authority to involve all other interested stakeholders in the process. The other change is that the proposal sets the default deadline for issuing the production permit to 3 years. In case of capacity below 50 kW, the permit needs to be issued by the regulator within 6 months, If this deadline expires, the producer automatically becomes eligib-

Table 1 Average cost of PV production

	Germany	Hungary	Greece
Cost of capital, %	4%	11,3%	12%
Annual utilization, %	9,9%	11,4%	15%
Average cost (LCOE), €/MWh	65	101	79

Source: REKK estimate

le for the permit. If existing producing capacities are refurbished, the deadline for issuing the permit is 1 year.

Transportation

The uniform 10% renewable transportation goal of the 2020 package ends in 2020. The proposal retains the obligatory ratio below but gradually withdraws biofuels for food and fodder from the market:

- compared to the transport fuel sold in a specific year, biofuels and renewable electricity need to reach at least 1.5% in 2021 and 6.8% by 2030, following a specified path (article 25)
- the maximum use of biofuels for food and fodder purposes (also compared to the transport fuel sold in a specific year) has to be reduced from 7% to 3.8% between 2021 and 2030 and replaced by modern biofuels.

Heating/cooling

The expansion of renewable energy in Europe is electricity centred: the share of renewable electricity generation increased by 13 percentage points on average within the territory of the EU for the last 10 years. The same figure is 7 percentage points for heat. Promoting renewable heat generation is primarily the task of member states, without many measures on the level of European Union. Supposedly, this is because heat markets are country specific and rather fragmented even domestically. There is an EU regulation covering renewable production with reference to buildings (e.g. the requirement for buildings to consume almost no energy at all) and the promotion of combined generation (Directive on Energy Efficiency). District heating, however, comprises only 10% of the heat demand of the EU. In light of the above, the draft Directive tries to place heat generation into a more favourable position, applying a measure – already known in the field of energy efficiency – that would oblige member states to introduce a domestic allowance system regulating the production of renewable heat. Accordingly, the ratio of renewable heat would have to increase by 1 percentage point per year by every member state (article 23).

Member states are free to designate those parties that are subject to the directive, and energy service providers are mentioned by the directive only as an example. The obligation may be satisfied in three possible ways:

- physical mixing (e.g. biogas into the gas network),
- realisation of renewable heat production (e.g. in buildings or industrial processes)
- purchase and recognition of renewable heat produced by a third party investor

A separate article addresses district heating systems (article 24). The proposal introduces positive discrimination for heat generated from renewables. As a principle, if requested, all renewable heat (or heat from waste incineration) needs to be included in the district heating supply. Referring to insufficient network capacity, the producer of renewable heat can be refused only if all heat supply is already fully waste based/renewable/combined, but it still enjoys a priority over fossil based heat generation (may displace it). The consumer is eligible to disconnect from the district heating system only if it is not efficient according to the Directive on Energy Efficiency (min. 50% renewable or waste, or 75% combined) and the consumer switches to an individual or local communal renewable system. The member state may restrict the right for disconnection by obliging the consumer to prove that the alternative individual/communal system is more efficient than the replaced district heating service. In case of multi-apartment buildings, disconnection is allowed only for the building as a whole. The right to disconnect, therefore, is not the expansion of a general consumer right.

The adoption of this rule in Hungary would reduce the existing freedom to disconnect Because district heating in Hngary is normally based on combined generation (therefore qualifying as efficient), the new regulatory plan may reduce the scope of disconnection. Lastly, the proposal prescribes energy certification for district heating systems, recording the efficiency of the system, the renewable share of energy use and the emission of CO2.

Compared to the previous renewable directive, the proposed version places more emphasis onrenewable heat generation by applying the logic of energy efficiency obligation schemes to promote renewable based heat generation. It also underscores cost efficiency, pressing for the competitive allocation of subsidies, the partial integration of national support scheemes, and predictability of regulation.

Energy efficiency

In the field of energy efficiency, the Winter Package does not contain any real novelty, but aims to revisit and supplement already existing measures to broaden their impact. This is likely because the 2020 target is not in doubt, and the current regulation includes the most important areas of energy savings that do not need to be restructured in any major way.

The package amends the two most critical pieces of law, the Energy Efficiency Directive (2012/27/EU) and the Directive on the Energy Performance of Buildings (2010/31/EU), extending the regulation on the energy efficiency of products to new products, and announcing a new EU initiative to support the modernization of buildings to save energy.

The Directive on Energy Efficiency, adopted in 2012, sets the 2020 primary and final energy consumption in line with the 20% energy saving target of the EU, as specifies how member states should contribute to it (each member state sets its own non-binding target). The planned amendment raises the proposed non-binding 2030 EU target from 27% to 30%, and makes it a compulsory EU commitment. During this period member states have to announce their planned 2030 energy use and by 2030 the primary energy use of the EU should fall below 1321 Mtoe final energy use 987 Mtoe.

The other important amendment concerns the 7th article of the Directive, on energy efficiency obligation schemes. Under the obligation schemes between 2014 and 2020 the energy companies designated by the member states have to achieve new energy savings equivalent to 1.5% of the sold energy. While the obligation schemes may be replaced by other measures, in most member states (15 of them) such systems exist. Since about half of the planned 2020 savings are expected through this article and obligation schemes have proven their effectiveness, the proposal extends its force until 2030, while maintaining the 1.5% obligation level. The savings target set by the article can be reduced by 25% according to the regulation currently in effect. According to the proposal this option continues to be available, while the volume of energy produced by new renewable capacities of buildings will also be eligible. As a new requirement, a pre-set share of savings will have to take place in energy poor households.

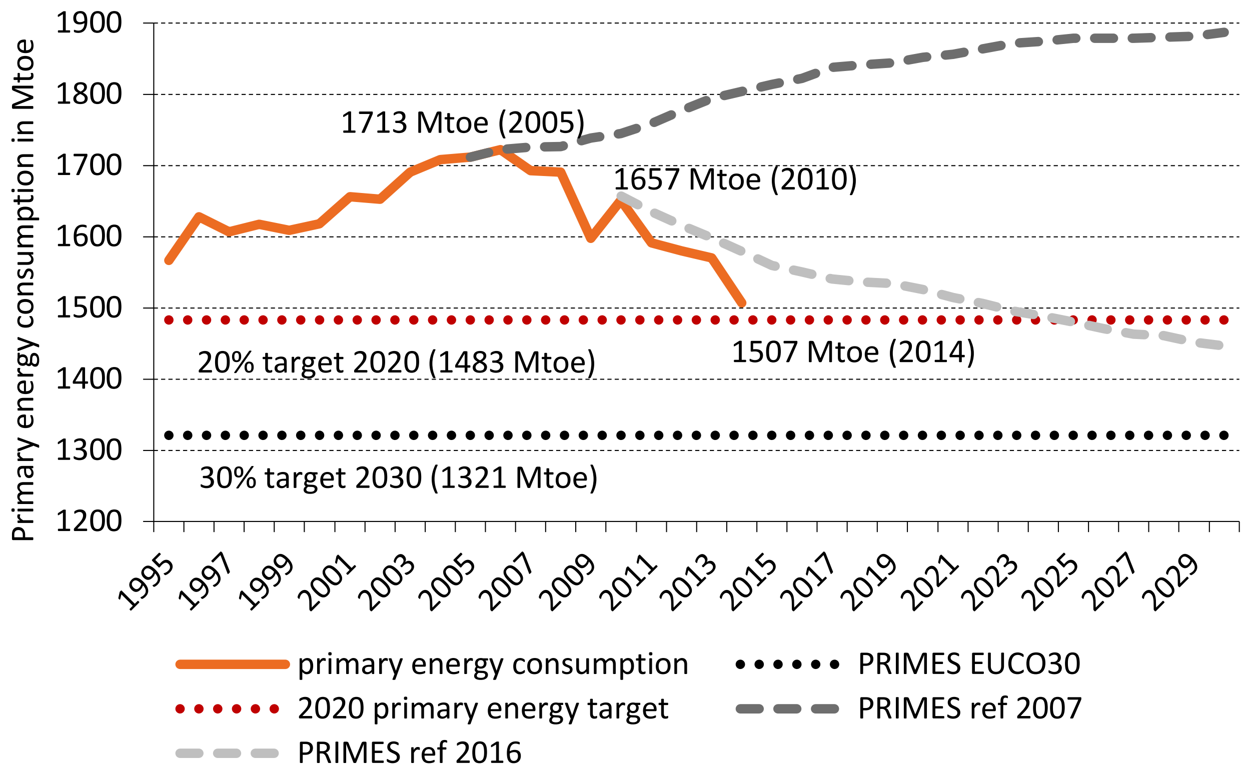
The Directive views the utilisation of saving opportunities of better informed consumers as a priority. An important area within this priority is the individual heat volume measurement of apartments in multi-apartment buildings. According to the proposal, starting in 2020 only appliances capable of distant measurement (heat volume meters and cost allocators) can be installed and existing devices that are not in compliance will need to be replaced by 2027. A few measures are transferred from the Directive to other regulations: metering and invoicing electricity appears in the regulation on the electricity market (while gas and heat metering remains here), and provisions on the building reconstruction action plan are moved to the Directive on the energy efficiency of buildings.

For buildings, the proposal prefers the application of building automation, the creation of a qualification system on the “level of smartness” of buildings, and addresses the installation of charging points for electric vehicles in for building reconstruction.

It’s almost a cliché that the energy modernisation of buildings is the most promising field of energy efficiency because of the large savings potential and it’s relatively low cost. Nevertheless even profitable investments are not always undertaken, partly because willingness to finance remains a challenge. This is advanced by the „Smart Finance for Smart Buildings”, supporting the creation of national energy efficiency platforms in order to efficiently combine various EU/national financial resources, financially support project development (aggregation of smaller projects, reduction of administrative barriers), and reduce the perceived/actual investor risk by collecting data on already implemented projects (https://deep.eefig.eu/).

The energy efficiency targets of the EU are moderately ambitious. The 2020 final energy target has already been achieved by member states in 2014 while primary energy requires an additional 2%. The 2030 target, set relative to the 2007 outlook, does not seem to be based on the trend of consumption. Perhaps it is not by coincidence that the European Parliament would have preferred to increase the 2030 target to 40%.

Figure 2 EU-28 Primary Energy Consumption Target



„Governance"

This expression refers to the cooperation framework of participants involved in common decision making and the related implementation. The Winter Package proposal on governance determines the tasks and responsibilities for the European Commission and the member states to support 2030 EU targets on energy and climate. But why is this new mechanism needed?

There are two methods to "allocate" EU level targets among member states. Using various principles the Commission sets member state targets, which – if all member states "deliver" – automatically ensures the attainment of the EU target. A good example for this is the sharing of the 20% target of 2020 on renewable energy among member states, in consideration of their baseline level and economic conditions. Another example is the 2020 member state emission limits for non-ETS sectors.

The other method is the so-called collection of member state contributions. In this case, the countries volunteer to take on specific targets with the overall EU target in mind. In this instance, however, the sum of member state contributions may not be enough to reach the EU goal. A good example of this method is the 2020 energy efficiency target. The consequences of low member states ambition is unclear since in this specific instance member state commitments are enough to reach the 20% target. Since the current trend points toward the commitment based methods (as the 2030 renewable energy target is also likely to be executed through this method unlike the 2020 target, while the sharing of the energy efficiency target may continue to use this scheme even beyond 2020), developing a better structured planning and monitoring system with increased authority for the Commission is advisable.

The system of "governance" will be regulated by a decree, a piece of regulation that is fully binding and that has to be applied directly. It will be reviewed by the European Commission in 2026 and amended based on the experience of implementation progress in international climate negotiations. Member states have to prepare two plans initially. First, a long term low GHG emissions strategy with a time horizon of at least 50 years. Second, an integrated national energy and climate plan, always for a 10 year period, with the first such plan covering the 2021-2030 period. Planning/reporting is not a new development within the EU. The two proposed amendments replace about 50 currently applicable planning and reporting obligations. Today member states report on interrelated fields at differing times, and consequently, under diverging assumptions. The proposal intends to terminate this inconsistency, enabling the comparison of member state data.

The deadline for the first complete version of the plan for the period of 2021-2030 is 1 January 2018, before which all member states are obliged to consult with neighbouring and other countries on the possibility of regional cooperation. The results of these discussions will be presented and the Commission will assess whether the defined national targets are adequate to reach EU targets and if current and planned measures are sufficient to reach the national targets. The national plans submitted to the Commission are reviewed by the rest of the member states. Taking into account the comments made by the Commission and member states, the final version has to be completed by 1 January 2019. Each member state can review the plan, but only once, in 2024, and the targets can only be revised upwards. Every two years member states have to report on implementation which is aggregated by the Commission.

The draft decree provides a detailed description of the mandatory elements of the plan. Among others, each member state needs to disclose its ideas related to the 5 areas of the Energy Union on the 2030 time horizon:

- Decarbonisation: legally binding emission limit for non-ETS sectors
- Renewable energy: contribution to the 27% EU target (in a sector breakdown)
- Energy efficiency: contribution to the 30% EU target (primary and/or final energy use expressed in absolute terms)
- Internal energy market: expansion of cross-border capacities, considering the 15% target, plans on connecting markets
- R+I: deciding on sources and technological goals.

After introducing the current situation, the integrated energy and climate plan has to outline at least two scenarios for all topics on a time horizon until 2040 describing the impact of the current and planned measures (with existing measure – WEM and with additional measures - WAM). The energy production/consumption and emission scenarios need to be based on a single, integrated energy model covering all sectors. Furthermore, the macroeconomic, environmental, employment and other social impacts of the scenarios also need to be introduced.

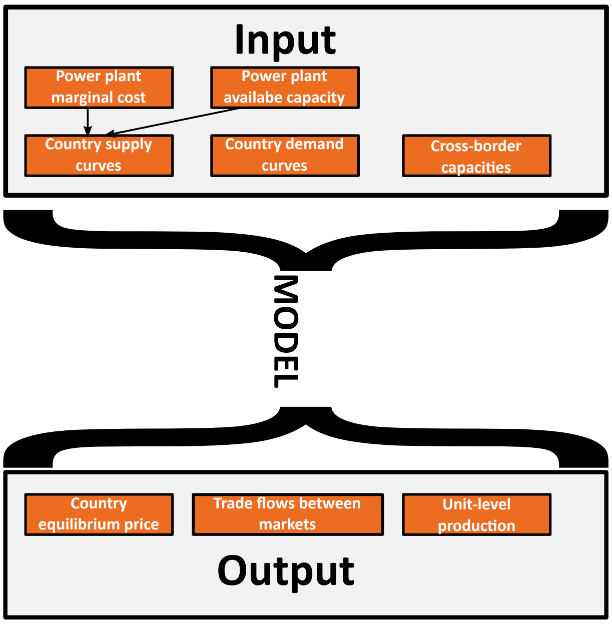
In addition to planning and reporting, another fundamental question concerns the power granted by the proposal to the Commission for enforcing the achievement of EU targets. At first reading, the draft text does not treat each area uniformly, with the most specific proposals for the instruments formulated to reach the EU renewable energy target. If by 2023 the EU share of renewable energy does not reach the proportionate value of the linear path between 2020 and 2030, then the member states:

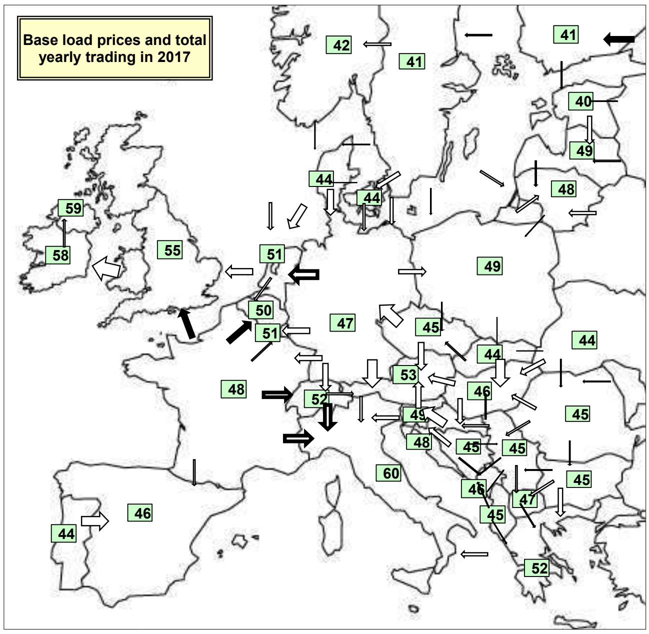
- Need to increase their obligation on renewable heat (Renewable directive, article 23)
- Need to increase their obligation on mixing modern biofuels (Renewable directive, article 25)
- Need to contribute to the fund financing renewable energy projects, supervised by the Commission.

As an important principle, the supplementary measures expected from member states consider the extent to which each has contributed to the 2030 goals, thereby providing an incentive for considerable early commitments. In case of “losing” the obligatory 2020 renewable ratio, the member states will again have to make a payment to the above fund. The proposal does not specify how the level of the contribution will be determined.

EUROPEAN ELECTRICITY MARKET MODEL (EEMM)

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





ASSUMPTIONS

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

USAGE

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

RESULTS

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

REFERENCES

- Ranking of Project of Common Interest (PECI) projects
- Evaluating the TYNDP of ENTSO-E
- Assessing the effects of the German nuclear decommissioning
- Analysing the connection between Balcans and Hungarian power price
- Forecasting prices for Easterns and Southeast European countries
- National Energy Strategy 2030
- Assessment of CHP investment
- Forecasting power plant gas demand
- Forecasting power sector CO^2 emmissions

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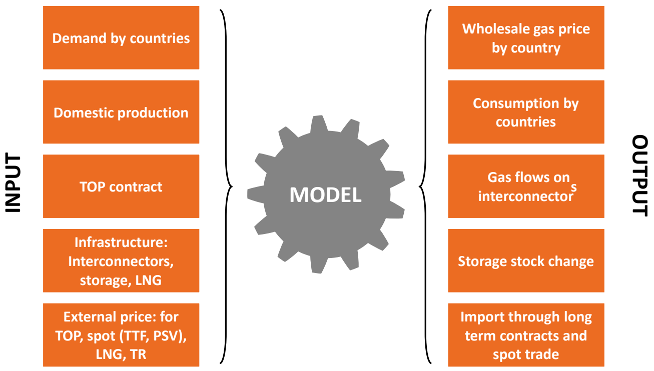
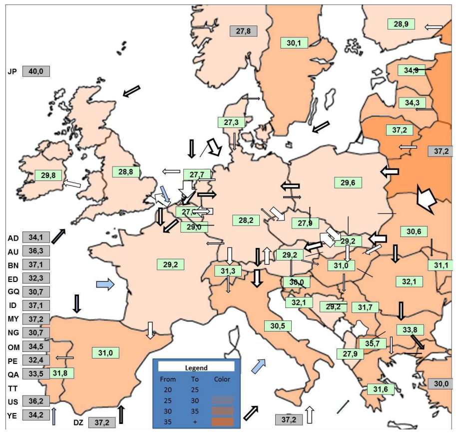
EUROPEAN GAS MARKET MODEL (EGMM)

EGMM is the natural gas market model of REKK developed since 2010 modelling 3 countries





ASSUMPTIONS

- Perfect competitive market
- Model ling period of one year (1 2 months)
- LTC and spot trade in the model led countries, pipeline and LNG suppliers
- Physical constraints are interconnection capacities
- Trade constraints: TOP obligation
- Model includes domestic proiduction and storages
- Model calcu lates with transmission nd storage fees

USAGE

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

RESULTS

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

REFERENCES

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

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