REKK
REGIONAL CENTRE FOR ENERGY POLICY RESEARCH

HUNGARIAN ENERGY MARKET REPORT

Q2 2014

REKK REGIONAL CENTRE FOR ENERGY POLICY RESEARCH

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

Training programs

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

Research

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

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

Consultancy

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

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

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

Dear Reader,

In our summer issue four working papers are published. We hope that our present publication – with more than usual emphasis on the current topics of regional and EU energy policy – will appeal to our readers in both the natural gas and the electricity sector. I continue to encourage all our partners to assist with their valuable feedback in our pursuit of tailoring the content of the report to the demands of our subscribers.

In our first article we take a close look at the security of supply risks generated by the recurring political crisis between the Ukraine and Russia. If the delivery of gas is suspended or a trade ban is imposed, the countries of Central and Eastern Europe will be deprived of substantial volumes of Russian natural gas import. Using modelling tools we assess the price increase that would be elicited by substituting the lost sources of the region, and we also inspect the level of consumption restrictions needed to offset the missing sources of import. In our analysis we examine the impacts of different scenarios of import loss with respect to their level, duration and timing.

In our second article we scrutinise the present situation and the expected future of European shale gas production. We briefly review the shale gas extraction related regulatory attitude of the European Commission and the EU member states, then using the examples of the UK and Poland we present the instruments with which countries planning to extract non-conventional sources try to facilitate the launch of production. Our American expert, Nolan Theisen presents the contrast between Europe and the United States quite conspicuously, outlining the conditions that the countries of the region ought to create so that the production of non-conventional supplies could start in large volumes.

The third article reviews the progress achieved in the development of European smart grids, describes the – different – investment strategies of individual states and provides insight into some of the interesting nuances of cost-benefit analysis, especially the challenges of project financing and the factors driving returns. The article also covers the domestic situation, summarising the results of the most recent study laying the foundation for the cost-benefit analysis to be submitted to the Commission.

In the last article of our report we present the guidelines of the European Commission on the future judgment on state aid for environmental purposes. The rules set by the corresponding document essentially seal the fate of feed-in-tariffs (FIT), a long term favourite among policy solutions. In our analysis we provide a detailed description of the requirements that future renewable support schemes need to satisfy in order to avoid the legal disputes between EU organisations and the member states.

Péter Kaderják, director

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Energy market developments

During the first quarter of 2014, crude oil and coal prices were largely stable, significant movements in prices were not observed. At the same time, international gas prices have shifted somewhat: Japanese LNG import prices rebounded compared to the prior quarter, the American Henry Hub prices spiked to their highest level in many years, whereas the day-ahead price of the Dutch TTF hub moderated considerably. While natural gas prices remain relatively high in Europe, German day-ahead power prices continued to decline during the quarter: thanks to these developments, the clean spark spread – i.e. differences between power and fuel prices, a measure of the profitability of gas-fired power plants – is still strongly negative.

Hungarian electricity consumption came in at 10 TWh for the quarter, that is, largely unchanged from the previous quarter. The share of power imports in domestic consumption moderated somewhat, but the 31% share can still be considered high. Hungarian day-ahead power prices remain the highest in the region, a phenomenon that can, among other factors, be traced back to low hydroelectricity production in the Balkans, and also to congestion on Hungary's cross-border electricity interconnectors. However, the price of the HUPX exchange still managed to narrow the gap compared to its German, Czech and Slovakian peers. Market coupling of day-ahead markets plays an important role in price convergence: in close to three-fourths of the hours during the quarter Hungarian and Slovakian day-ahead prices were equal, representing a much higher ratio than prior to the market coupling in 2012.

In the first quarter, natural gas consumption in Hungary was significantly lower than in the comparable period of 2013 – though as we will show below, this was largely due to the relatively cold first quarter in 2013 and the March cold spell in particular, which provided an exceptionally high consumption basis. Domestic gas production was unchanged from the last quarter at 625 million m^3. Natural gas imports meanwhile amounted to 2.25 billion m^3, of which 59% were imported from Austria, 36% from the Ukraine and the remainder from Romania. Storage level of Hungarian natural gas storage facilities continues to be the lowest in the region, at the end of March 2014 – i.e. the end of the withdrawal period – utilization of commercial storage facilities were a meager 7.5%.

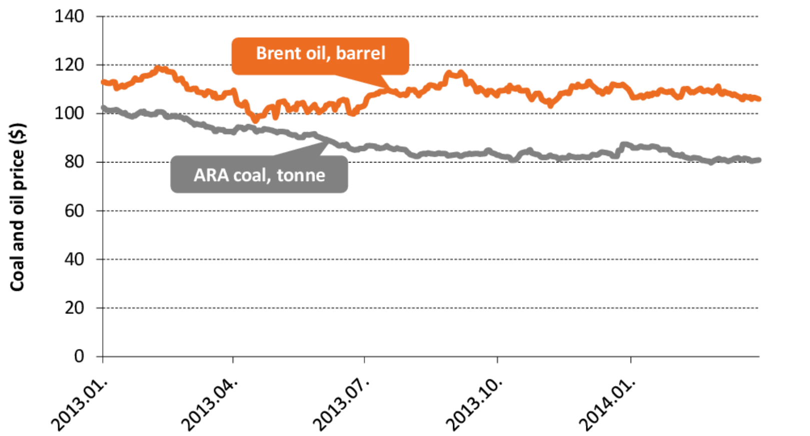
International price trends

In the first quarter of 2014, the price difference between crude oil and coal remained stable. In this period, Brent traded in the range of 105-112 $ a barrel, closing the quarter at 106 $. Meanwhile, the price of ARA coal traded at the EEX energy exchange was mildly decreasing until the end of March, moderating from a per-tonne price of 87 $ to 80 $. (*Figure 1*)

Figure 2 shows price developments on some of the major gas markets. Compared to the end of 2013, two of the four prices registered a slight increase by the end of March: the quarterly average price of Japanese LNG imports increased from 37.05 €/MWh to 38.33 €/MWh, while the quarterly average of the North-American Henry Hub spot price was up from 10.56 €/MWh to 12.10 €/MWh compared to the prior three-month period (meanwhile, both the Japanese yen and the U.S. dollar remained stable vis-à-vis the euro). It is important to note that due to a North-American cold spell the price of Henry Hub gas was exceedingly high in February, registering a monthly average of 15 €/MWh (6 $/MMBtu), the highest value since November 2008. In contrast, the average price of gas imported by Germany under long-term Russian contracts declined by close to 1 €, while the spot price of the Dutch TTF hub dropped more considerably, from 27.75 €/MWh in December to 22.90 €/MWh in March.

The price of German power futures moderated further in the first quarter: baseload prices eased from 6 €/MWh at the end of December to the vicinity of 34 €/MWh by the end of March, while peak load prices dropped below

Figure 1 **EEX-traded year-ahead ARA coal futures price, and the price of Brent crude oil from January 2013 until March 2014**



Source: EEX, IEA

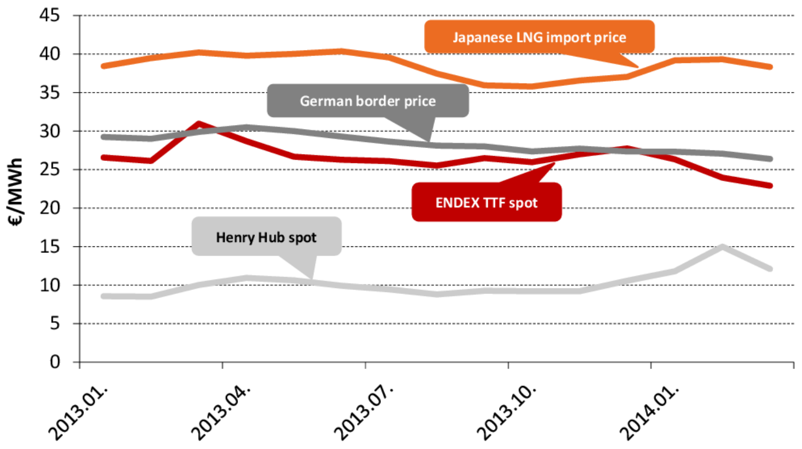
44 €/MWh from 47 €/MWh. CO_2 credits (EUA) with next December delivery started off the year with a price of 5 €/t: from the beginning of January, however, the EUA price increased, rising above the 7 €/t mark by the end of February, from which then it started to decrease slowly in March and dropped steeply at the end of the month to close the quarter at 5 €/t (*Figure 3*).

The profitability of gas- and coal-fired power plants can be measured by two kinds of price differences: with the clean spark spread in case of gas-fired plants, and with the clean dark spread in case of coal-fired generation. Both indicators show the difference between electricity prices on exchanges and the cost of electricity generation, where generation costs are represented 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. *Figure 4* shows the monthly averages of these two indicators, which are calculated using spot baseload power prices on the German EEX exchange. The clean dark spread, indicating the profitability of coal-fired power generation, decreased substantially in the first quarter of 2014, dropping from 16 €/MWh to below 11 €/MWh. In contrast, the persistence of the strongly negative values of the clean spark spread indicate that gas-fired power plants operate with considerable losses: the daily average of this indicator has been positive on a mere 20 trading days since the beginning of 2013.

Overview of the domestic electricity market

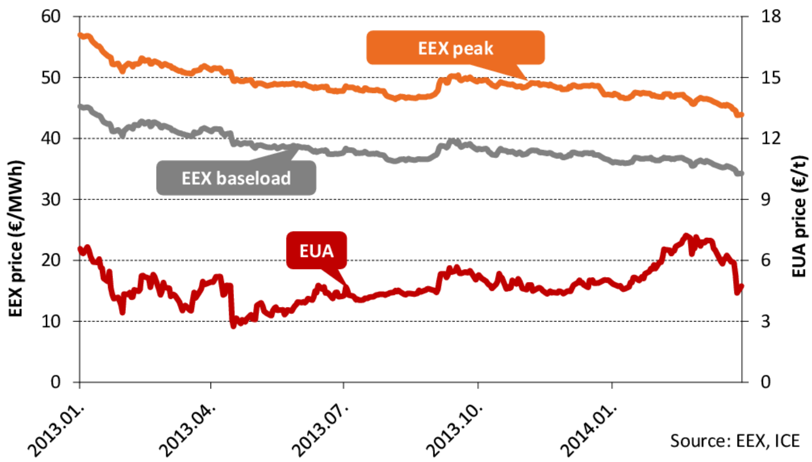
At the monthly cross border auctions (*Figure 5*) the price for the Slovakian import capacity exceeded 6 €/MWh in February and 3 €/MWh in March. Apart from the Slovakian import capacity, only the Romanian one exceeded 1 €: in January and February it was around 2 €/MWh, and in March it was somewhat higher than 1 €/MWh. Cross-border capacity prices at all other borders fell short of the 1 €/MWh mark, while at the Austrian border no import capacity rights were allocated. The reason for

Figure 2 **Prices on select international gas markets from January 2013 to March 2014**



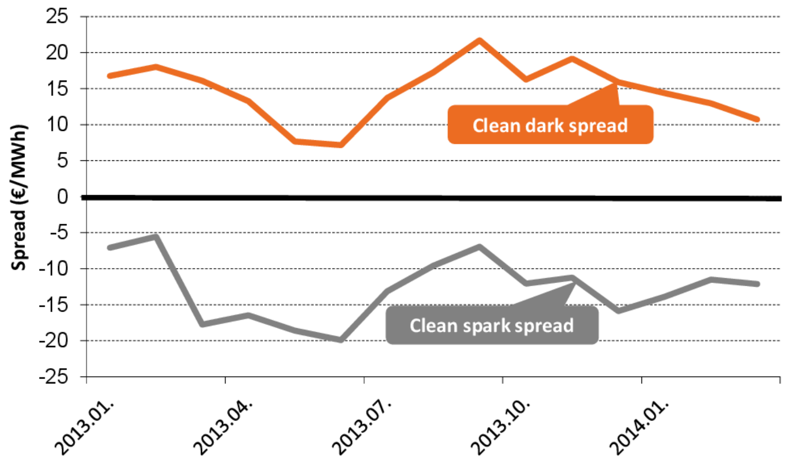
Source: Statistical Office of Japan, EIA, Gaspool, IMF

Figure 3 **The price of year-ahead EEX power futures and the price of CO_2 pollution permit (EUA) futures with next December delivery from January 2013 to March 2014**



Source: EEX, ICE

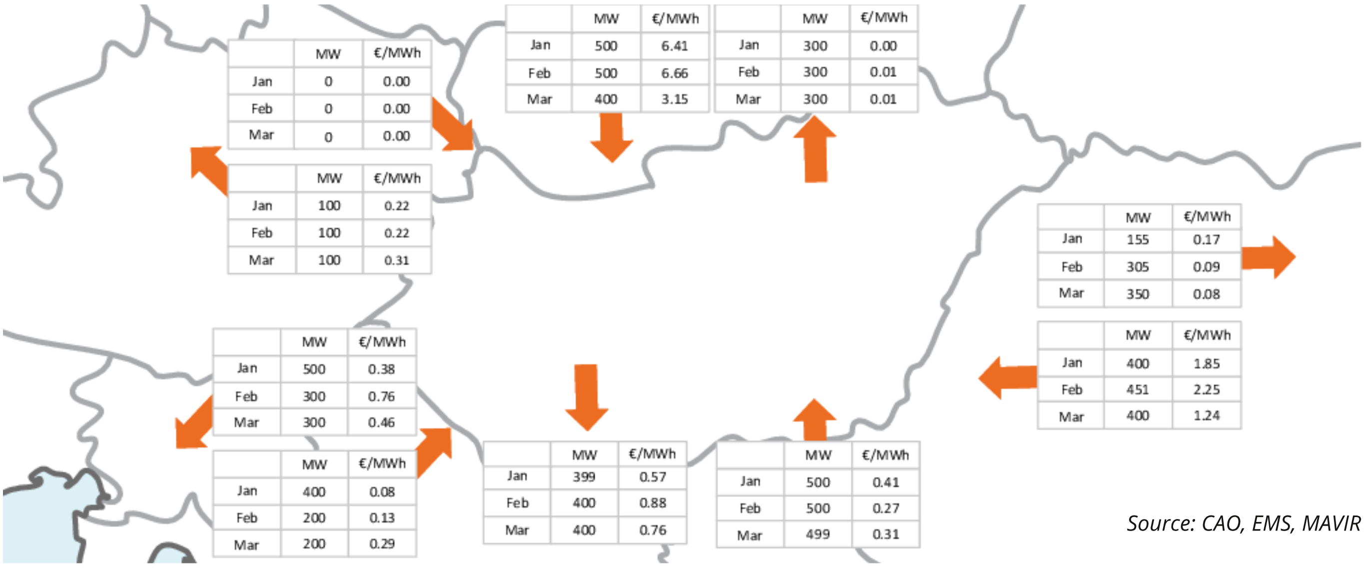
Figure 4 **The clean spark spread (for gas-fired power plants) and the clean dark spread (for coal-fired power plants) on the German market between January 2013 and March 2014**



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

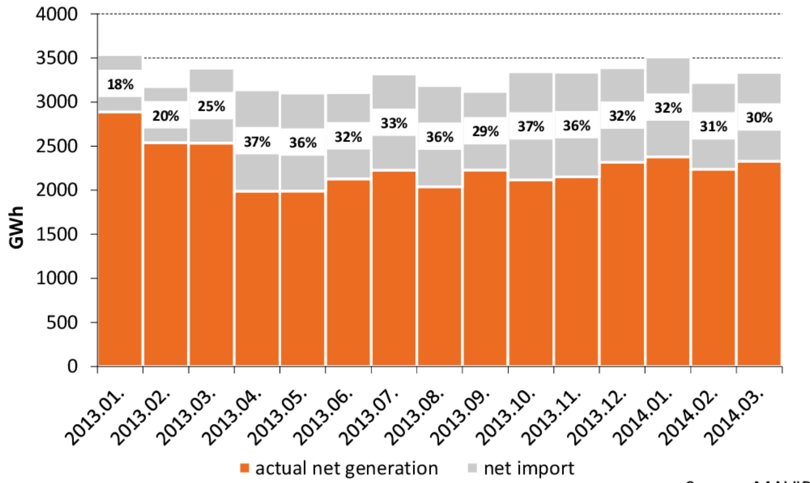
Note: In our calculations we assumed an efficiency of 50% for coal-firead and 38% for gas-fired power plants.

Figure 5 **Results of monthly cross-border capacity auctions in Hungary, Q1 2014**



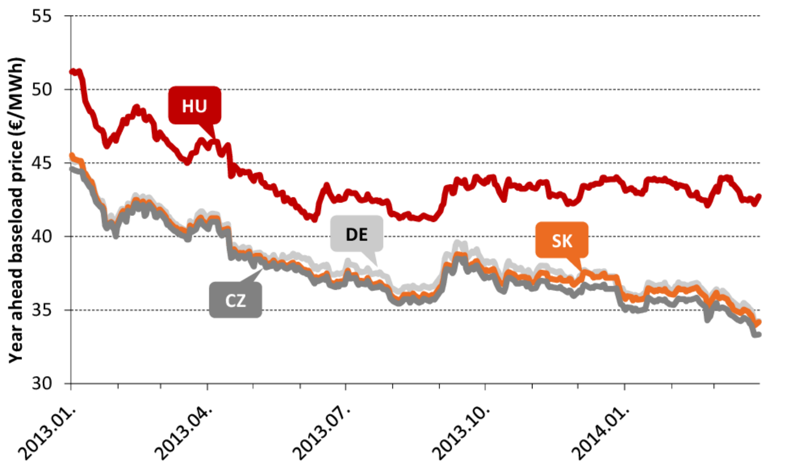
Source: CAO, EMS, MAVIR

Figure 6 **Net electricity production of Hungary's power plants, and monthly net electricity import of Hungary between January 2013 and March 2014**



Source: MAVIR

Figure 7 **Baseload futures prices with year-ahead delivery in select countries of the region between January 2013 and March 2014**



Source: EEX, HUPX, OTE

this is not capacity retention, but that capacities are being allocated on daily instead of monthly auctions.

In the first quarter electricity consumption (*Figure 6*) was 10.07 TWh, which is only a very slight change from the 10.1 TWh a year earlier. While electricity consumption declined by 1% in January and 1.7% in March year--over-year, in February a 1.4% yearly growth was registered.

Since the spring of 2012 the selling price of domestic power plants had been considerably higher than that of import sources, and as a consequence, the import share in Hungary's electricity consumption was increasing: following the 18-20% level observed in the beginning of 2013, the import share exceeded 30% in all but one month since April 2013. In the first quarter of 2014, the average import share was 31% (3.1 TWh), and in contrast with the tendency in earlier years, we did not observe a significant drop in the import share during the winter months.

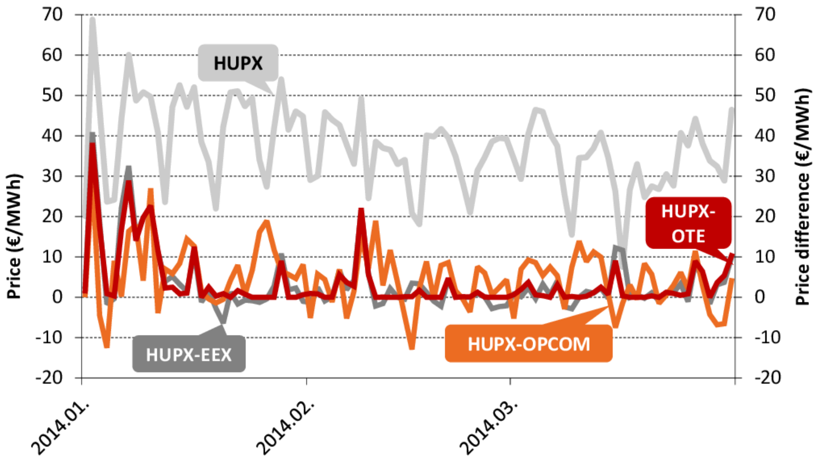
The baseload power price with year-ahead delivery (*Figure 7*) was decreasing in the first quarter on the German, Slovakian and Czech markets, in the period of January-March prices were seen falling by around 1.5 € on all three markets compared to the fourth quarter of 2013. Hungarian prices did not follow the decreasing trend observed on the aforementioned markets: the average Hungarian price in both quarters were slightly above 43 €/MWh. This means that while in the fourth quarter of 2013 Hungarian prices were on average 5.7 € higher than the futures prices on the German EEX exchange, this gap widened to 7.1 € by the first quarter of 2014. Similarly to the prior two quarters, Czech power futures were traded at a 1 €/MWh discount compared to the German market.

Figure 8 shows the day-ahead baseload price of the HUPX power exchange and also price differences between the HUPX and three other regional exchanges (the German EEX, the Czech OTE and the Romanian OPCOM) in the first quarter of 2014. With the exception of the first two weeks of 2014 – when HUPX and OPCOM prices exceeded those of the EEX and OTE – electricity prices exhibited only slight price differences. In January, HUPX prices were pushed higher as two blocks of the Paks nuclear power plant halted production: one block was suspended starting from November for scheduled maintenance, while another block ceased production due to an unscheduled outage in early January. The return of these two blocks in mid-January provided a downward pressure on Hungarian prices. During February, HUPX day-ahead prices were close to regional peers despite hydroelectricity production in the Balkans remaining low until the end of March.

During the fourth quarter, the Romanian prices tended to be the lowest in the region, while Hungarian prices were usually the highest. It is important to note that while in the fourth quarter of 2013 HUPX prices were on average by 10 € higher than the average price of the three other exchanges, in the first quarter of 2014 the average price difference moderated to 3.9 €, and in February and March it was less than 3 €.

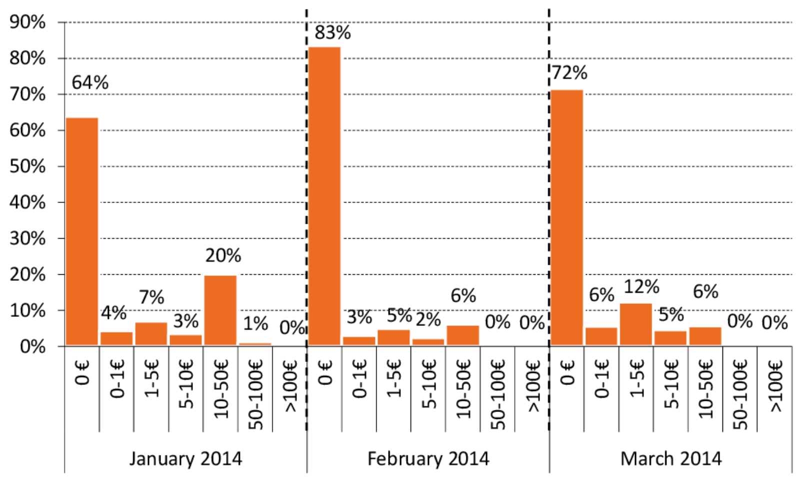
The effect of market coupling can be assessed based on hourly price differences between the Hungarian and Slovakian power exchanges. *Figure 9* shows the frequency – i.e., the percentage of hours – in which prices were equal or different to a certain degree during the January-March period. We can see that prices were equal in 64% of the hours in

Figure 8 **A comparison of day-ahead baseload prices on the EEX, OPCOM, OTE and HUPX exchanges between January-March 2014**



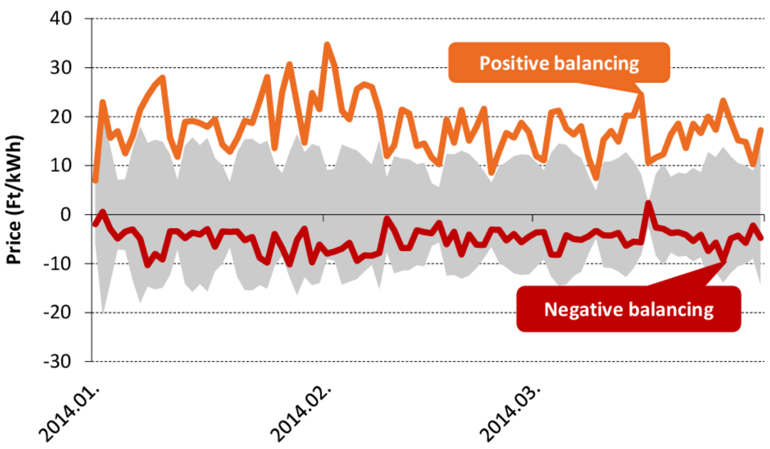
Source: EEX, OPCOM, OTE, HUPX

Figure 9 **The frequency of various levels of price difference between the Hungarian and the Slovakian exchanges during January-March 2014**



Source: REKK calculations based on OTE data

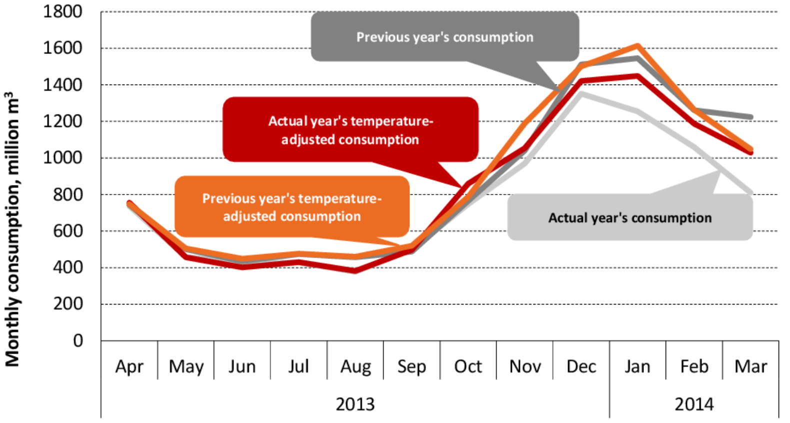
Figure 10 **Daily average of the balancing energy prices and the spot HUPX price, Q1 2014**



Source: MAVIR, HUPX

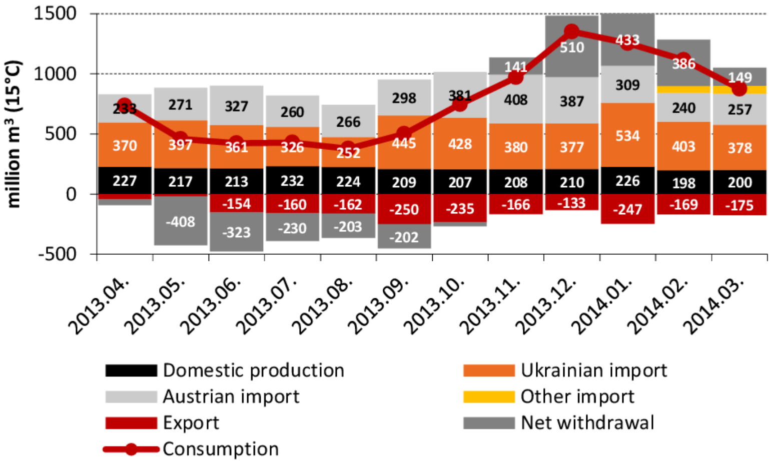
Note: The upper edge of the grey range in the figure is determined by the day-ahead price of HUPX, while the lower edge is the opposite of the same price. According to the Code of Commerce of MAVIR the price of positive balancing power is limited to the day-ahead price on HUPX, while the price of negative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

Figure 11 **Raw and temperature-adjusted monthly natural gas consumption between January 2013 and March 2014, compared with the respective data in the previous year**



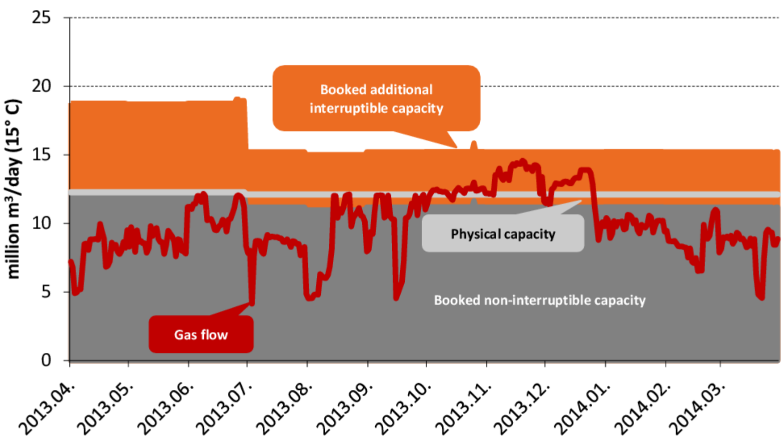
Source: FGSZ, European Climate Assessment & Dataset, and REKK calculations

Figure 12 **The source structure of the gas market of Hungary by month between January 2013 and March 2014**



Source: FGSZ

Figure 13 **Transmission at the Mosonmagyaróvár (Austrian border) entry point between January 2013 and March 2014, together with booked interruptible and non-interruptible capacities**



Source: FGSZ

Note: The value of physical capacity is shown as provided by FGSZ.

January, 84% in February and 72% in March. Additionally, in January Hungarian prices exceeded by 10 € or more their Slovakian peers in more than 20% of the hours – such large differences occurred much less frequently in February and March. It is important to note that there were no hours when Slovakian prices were higher than Hungarian ones, while Slovakian and Czech prices were equal in almost all of the hours: hourly prices differed in only seven instances during the quarter.

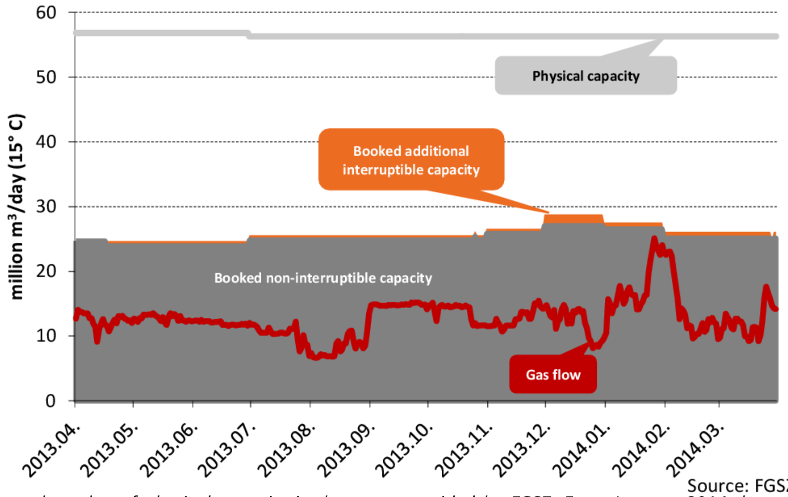
The wholesale price is impacted by the costs arising from the deviation from schedule and balancing energy prices. The system operator determines the accounted unit price of upward and downward regulation based on the energy tariffs of the capacities used for balancing. The order of using these capacities is established based on the energy tariffs offered on the day-ahead regulatory market. The system for charging balancing energy has been developed by MAVIR so that it provides incentives to market participants to try to manage foreseeable deficits and surpluses through exchange based transactions – in other words, covering the expected deficit and surplus through the balancing energy market should not be attractive for them. For this purpose, the price of upward balancing energy cannot be lower than the HUPX price for the same period, while the system operator does not pay more for downward balancing energy than the price at the exchange. During the first quarter the average price of positive balancing energy was 18.1 HUF/kWh, exceeding the 23.3 HUF/kWh value of the prior quarter, while the average price of negative energy was –5.1 HUF/kWh, which was, in absolute value, a decrease from the –8.5 HUF/kWh in the previous quarter (*Figure 10*).

Overview of the gas market in Hungary

Figure 11 depicts monthly natural gas consumption compared with the consumption level of the respective month in the prior year. The figure also shows gas consumption adjusted with heating needs, which depend on the daily mean temperature. We can see that gas consumption in all three months of the first quarter lagged considerably behind the consumption in the respective period of last year: this year's consumption was lower by a total of 907 million m^3 – consumption was down year-over-year by 414 million m^3 in March only. However, temperature-adjusted data highlight that this was mainly due to differences in temperature. This is especially visible when comparing March 2014, a relatively warm period, with March 2013, a month characterized by record low temperatures: in this case, the temperature difference by itself is able to explain the sizeable year-over-year drop in gas consumption.

Hungarian gas production was 625 million m^3 in the first quarter, the same as in the fourth quarter of 2013. Hungary imported 2.25 billion m^3 of gas, and exported 0.59 billion m^3, meaning a net import of 1.66 billion m^3: this represents a 9.4% reduction compared to the prior quarter. During the first three months, 58.6% of imports arrived to Hungary via Ukraine at the Beregdaróc entry point, while 35.9% arrived via Austria at Mosonmagyaróvár. Romania also appeared as a source country for the first time in the FGSZ data set: 5.5% of all imports arrived through this country. (*Figure 12*)

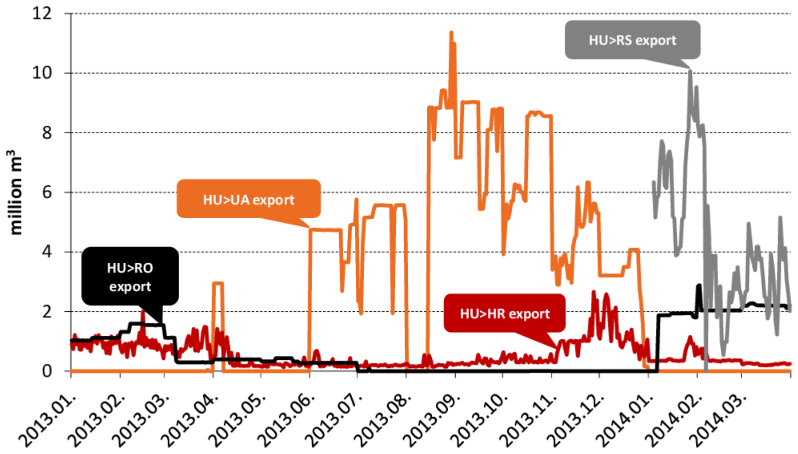
Figure 14 Transmission at the Beregdaróc (Ukrainian border) entry point between January 2013 and March 2014, together with booked interruptible and non-interruptible capacities



Source: FGSZ

Note: the value of physical capacity is shown as provided by FGSZ. From January 2014 data also contains transit gas flows entering Hungary via Ukraine and leaving in the direction of Serbia and Bosnia-Herzegovina

Figure 15 Hungary's natural gas exports to Ukraine, Croatia, Romania and Serbia from January 2013 to March 2014



Source: FGSZ

Note: FGSZ provides transit gas flows leaving the country at the HU>RS (Kiskundorozsma) point in the direction of Serbia and Bosnia-Herzegovina since January 2014 only.

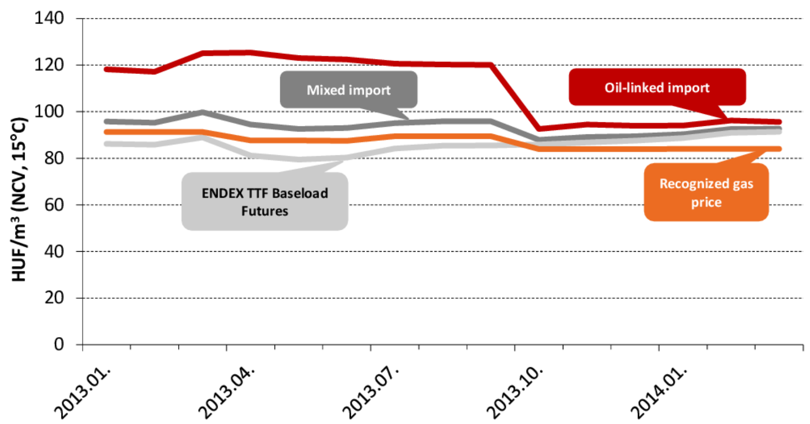
At the end of March – i.e. the end of the withdrawal period – Hungary's commercial gas storage facilities, owned by Hungarian Gas Storage Ltd., were filled only to 7.5%, while the strategic storage facility at Szőreg had a utilization level of 47.6% – this means an average utilization of 19.9% for all storage facilities in Hungary. At the same time, storage utilization was 37% in Austria, 40% in the Czech Republic, 69% in Poland and 58% in Germany – meanings that gas storage utilization in Hungary continues to be very low, considerably lower than in other countries of the region.

In the first quarter 807 million m^3 gas entered Hungary via Mosonmagyaróvár (*Figure 13*), which is 37% lower than in the prior quarter, and also 16% lower than in the first quarter of 2013. During the quarter, 74% of the physical capacity of the entry point and 59% of all booked capacities were utilized. At the monthly import capacity auctions a capacity of 41.9 million MJ/day was offered in the end of 2013, which was reduced to 31.4 million MJ/day from the beginning of 2014 and further reduced to 21.3 million MJ/day for the 2014-15 gas year. According to data disclosed by transmission system operator FGSZ, in the end of 2013 usually only 25-26% of all offered capacities were booked at monthly capacity auctions, while the annual capacity product for 2014-15 was close to four times oversubscribed at the auction held in April.

In the first quarter 1.31 billion m^3 natural gas entered Hungary from Ukraine (*Figure 14*), which is 26% higher than in the comparable period of 2013. Physical utilization of the Beregdaróc entry point was only 26%, while 55% of all booked capacities were used.

Figure 15 shows Hungary's gas exports to Ukraine, Croatia, Romania and Serbia. Total exports to these four countries were 590 million m^3 in the first three

Figure 16 **Recognized natural gas selling price of universal service providers, and factors of the gas price formula between January 2013 and March 2014**



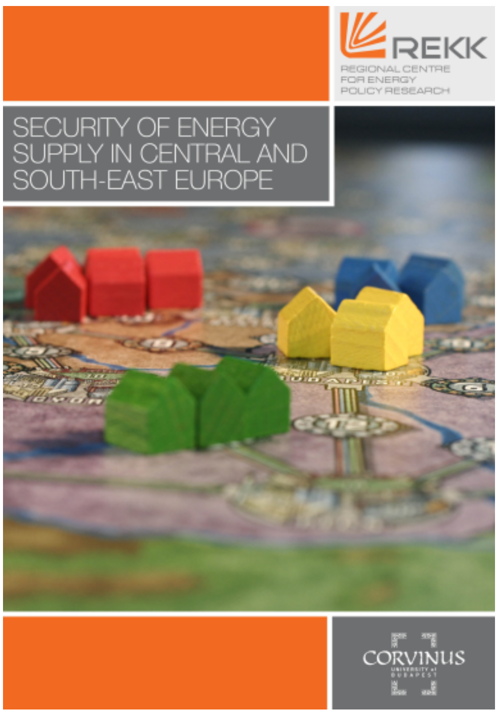
Source: REKK calculations based on EIA and ENDEX data

Note: The "recognized natural gas price" is an estimate by REKK for the regulated price calculated by the Hungarian energy regulator (MEKH) every quarter – the estimation is based on the regulated gas price formula and the EUR and USD exchange rates used by the regulator, using publicly available information. The estimate does not account for the effects of natural gas from storage facilities on the recognized price, which is also part of the gas price formula. We calculate the price of "mixed import" similarly, but in this case we use market exchange rates instead of those set by the price regulation decree.

months of 2014. According to data published by FGSZ, gas exports to Ukraine halted from the beginning of 2014, while 64.6% of all Hungarian exports went to Serbia, 29.6% to Romania and 5.7% to Croatia in the quarter.

Figure 16 shows that the oil-linked gas price was slightly higher in the first quarter of 2014 compared to the prior quarter, the average price in the January-March period was 95.3 HUF/m^3. However, the recognized import price of universal service providers, a weighted average of 70% exchange-traded TTF and 30% oil-linked prices , was practically unchanged at 84 HUF/m^3, compared to 83.9 HUF/m^3 in the previous quarter. The earlier seen discount in TTF futures prices compared to the oil-linked price has almost disappeared by March 2014, the TTF price was by only 1 HUF/m^3 lower than the oil-linked price: this can be mainly attributed to E.ON successfully renegotiating the gas import price formula during the fall of 2013. It can also be seen that the exchange rates used in the price regulation – currently 279.1 HUF/EUR and 210 HUF/USD – resulted in the regulator underestimating the actual cost of gas (the "mixed import" price): the recognized price was therefore by 7.8 HUF/m^3 lower than the actual import price.

Security of Energy Supply in Central and South-East Europe



REKK has published the volume containing the studies of the SOS project started in 2009. The papers of this book were motivated by the wish to get a better understanding of the threats and challenges to gas and electricity supply security in a number of countries in Central and South Eastern Europe (CSEE). We very much hope that the reports of this volume, which have been prepared in an exceptional collaborative effort by the colleagues of the Regional Centre for Energy Policy Research, will be helpful for the executives of those companies interested in investing into the energy sector of the region and can also provide food for thought for European and local policy makers and regulators concerned about energy supply security in CSEE.

The entire publication can be downloaded free of charge from the Books section of the rekk.eu website.

Impact of a possible embargo situation related to the ongoing Ukrainian crisis

The unfolding political crisis between Ukraine and Russia poses an immediate gas supply security risk for Europe but especially to Central Eastern Europe (CEE), the Baltic States and South East Europe (SEE)[1].

Political statements on both sides envisage a possible supply cut of natural gas. Since mid-March 2014 President Barack Obama has frequently announced the warning that Russia will pay the cost for any military manoeuvres it launches in the Ukraine. In his answer Vladimir Putin has warned the U.S. and the EU of “consequences” if they impose sanctions on Russia over its military intervention in Ukraine, saying they will backfire against the West. Putin said that the West should be bear in mind that it will also suffer damage from the sanctions. He called the sanctions "counterproductive and harmful.” April 10 Vlagyimir Putyin has warned in a letter addressed to several European leaders[2], that a „critical situation” might arise because Ukraine has not paid for gas deliveries on time.

Our modelling exercise in this article gives an estimate of loss of natural gas consumption due to a supply cut possible crisis situations in monetary terms. We try to estimate the wholesale natural gas price increase for CEE countries caused by a supply shock, as an indicator of the seriousness of a crisis. We also give an estimate for the shock in volume terms. Assuming that prices are frozen, less volume will reach the consumers: we call this difference loss of load (LoL) in this article.

A supply cut of Russian gas to the EU might be either due to unintended developments or to intended actions. An unintended supply cut (“failure”) might be caused by lost control over infrastructure management in, for example, an unfolding military conflict between Russia and Ukraine. An intentional supply cut might be a Russian response to western economic sanctions (“counter-sanction”) or be part of a Western embargo on Russian energy deliveries (“embargo”).

The principal difference between the unintended and the intended supply security incidents is that in an unintended case we assume Russia wanting to compensate and the EU willing to accept compensation for lost gas supplies through Ukraine by increased supplies through alternative routes (Yamal and Nord Stream). In an embargo or counter-sanction case, we do not expect this to happen.

Methodology: First we develop a set of “failure” and “embargo” type supply security scenarios for CEE, each defined in terms of reduced Russian gas supplies to Europe compared to a 2013 reference case. Next we quantify the impacts of these short term (<1 year) scenarios on wholesale gas prices and potential lost load in CEE using the European Gas Market Model (EGMM) developed by REKK[3].

SHORT TERM GAS SUPPLY SECURITY SCENARIOS FOR CEE

All supply security scenario simulation outcomes are compared to a reference case of EU industry at the end of 2013, represented by demand and supply characteristics, contractual constraints as well as infrastructure topology and capacity constraints. This infrastructure is expanded with the new Slovakian-Hungarian interconnector and Polish LNG receiving terminal in those reference scenarios with events taking place after June 2014. The supply security scenarios developed for the present analysis are explained in *Table 1*.

Scenarios differ by type. An unintended supply cut or failure compares closely to the 2006 and 2009 gas crises in CEE, when deliveries through Belarus and Ukraine were reduced by 30% and 100%, respectively[4]. In case of a failure we assume that Russia will compensate for lost supplies by shipments on alternatives pipelines up to available capacities. We investigate two alternative short-term failures: a full cut of different pipeline combinations in April 2014 (low season) and in January 2015 (high season).

In the case of a Western embargo the objective of the action is to reduce dependence on Russian gas supplies. We simulate the impacts of a 30% decrease in shipments on all Russia-EU pipelines for 3, 6 and 12 months.

[1] In this paper CEE consists of Austria, Czech Republic, Croatia, Hungary, Poland and Slovakia. Baltic states are: Estonia, Finland, Lithuania, Latvia, SEE countries are: Bulgaria, Moldova, Romania, Serbia and Bosnia Herzegovina

[2] The leaders of Germany, France, Italy, Austria, Hungary, the Czech Republic, Poland, Slovakia, Slovenia, Croatia, Serbia, Bosnia, Bulgaria, Romania, Macedonia, Greece, Turkey and Moldova

[3] For a detailed description of the regional EGMM see: Development and Application of a Methodology to Identify Projects of Energy Community Interest, Chapter 5.2 http://www.energy-community.org/pls/portal/docs/2558181.PDF

[4] For a detailed descussion on the lessons of the 2009 January gas crisis for CEE see Kaderjak (2011) 'The Lessons of the January 2009 Gas Crisis in Central and Eastern Europe', in: Vinois, J.A. (ed), The Security of Energy Supply in the European Union, pp. 193-219. Claeys and Casteels

Table 1 **Typology of supply security scenarios for CEE**

	Scenario type			
	Failure			Embargo
Length and time of supply cut	Cut of supplies through Ukraine only	Cut of supplies through Ukraine and Belorus	Cut of supplies through all pipelines to EU	Reduction of supplies through all pipelines to EU
	100%	100%	100%	30%
1 month (April 2014)*	X	X	X	
1 month (January 2015)	X	X	X	
3 months (April to June 2014)				X
6 months (April to Sept 2014)				X
12 months (April 2014 - March 2015)				X

** Scenario without HU-SK and PL LNG*

ANALYSIS OF SHORT TERM SUPPLY SECURITY SCENARIOS

An unintended supply cut in April 2014

In the following we simulate the consequences of a supply cut (i) on all pipelines through Ukraine, (ii) on all pipelines from Ukraine and Belarus, and (iii) on all pipelines from the Ukraine, Belarus, to the Baltic States and the Nord Stream. We assume that 100% of the deliveries in April are stopped. In the April scenario European demand is much lower than in the winter period, but storages are not yet filled[5].

Compared to the reference, a 100% supply cut from Russia in April would result in a 7-14% price increase in Central Eastern Europe, assuming prices are allowed to rise to encourage demand side adjustment to the supply shock. If, on the other hand, we assume that the reference price (28.4 €/MWh regional average) is unchanged, this would result in a 0.6-1.2 bcm non-served demand in CEE (*Table 2*). This means that in the worst case about one third of the demand would not be served.

Table 2 **Wholesale price effect/loss of load by a 100% Russian supply cut on different pipeline routes in CEE, April 2014 (monthly values)**

	CEE Regional average price	Price change relative to reference	Loss of load	% of demand served
	(€/MWh)	%	Mcm	%
Reference	28.4			
Ukrainian pipelines cut	30.5	7.4	684	83.0
Ukrainian and Belarusian pipelines cut	32.3	13.7	1145	71.1
All routes from Russia to Europe cut	32.5	14.4	1202	69.6

An unintended supply cut in January 2015

In the January scenario demand is peaking in Europe. Injection into storage has been completed in the summer and fall, anticipating normal winter conditions to come. We do not assume that extra strategic storage injections occur – traders decide commercially on how much storage they use, expecting no supply security problems.

The infrastructure in January 2015 is extended by the Hungarian-Slovakian interconnector and the Polish LNG terminal in Świnoujście. To allow for comparison with the previous table, we present the results also without these new pieces of infrastructure.

Supply cuts in 2015 January result in sharper wholesale gas price increases (12-38%) on an already higher reference monthly price when compared to the 2014 April cases (*Table 3*). At the same time the amount of lost load does not increase significantly (0.6-1.5 bcm).

It is of little surprise that the Slovakian-Hungarian interconnector and the Polish LNG terminal help in mitigating the damages to the region. The Polish LNG terminal delivers only to Poland and only when the Yamal pipeline is not delivering gas from Russia. Using the LNG terminal at maximum capacity, the price effect on Poland can be reduced from a 92% increase to a 58% increase. The Slovakian-Hungarian interconnector has a more widespread, regional effect. Connecting the cheaper Western Europe with the more expensive Eastern and South-Eastern Europe, the average price in Western Europe under the Ukraine cut scenario[6] rises from 4% to 6%, but in exchange there is significant reduction in Hungary (from 34% down to 19% increase), Romania (42% to 27%), Bulgaria (38% to 25%), Croatia (22% to 7%) and Serbia (34% to 25%).

[5] In April the 2013 infrastructure is in place, the only addition is that reverse flow on Yamal (German-Polish border) is allowed. It started operation 1 April 2014.

[6] The same price increase remains even under the more serious supply cut scenarios. The CEE region's position does not worsen with more serious failures and consequent supply cuts.

Table 3 **Wholesale price effect/loss of load and additional spot LNG to the EU prompted by a 100% Russian supply cut on different pipeline routes in CEE, January 2015 (monthly values)**

		CEE Regional average price	Price change relative to reference	Loss of load	Demand served	Spot LNG shipments to EU	
		€/MWh	%	mcm	%	TWh/year	bcf/year
Without SK-HU and PL LNG	Reference	32.2				24	81.6
	Ukrainian pipelines cut	36.2	12.4	762	89.2	28	95.2
	Ukrainian and Belarus pipelines cut	44	36.65	1373	79.23	41	139.4
	Everything from Russia to Europe cut	44.4	37.89	1511	77.08	49	166.6
		€/MWh	%	mcm	%	TWh/year	bcf/year
With SK-HU and PL LNG	Reference	32.2				24	81.6
	Ukrainian pipelines cut	35.3	9.6	629	91.2	31	105.4
	Ukrainian and Belarus pipelines cut	40.4	25.5	1189	82.6	48	163.2
	Everything from Russia to Europe cut	40.8	26.7	1382	79.7	60	204.0

A Western embargo

An intended supply cut means that either Russia is not willing to serve European consumers or Europe is not willing to accept natural gas deliveries from Russia. With reference to the intention of the European Council to define a policy package to reduce the EU's dependence on Russian gas supply[7], we assume an embargo scenario when the EU reduces its natural gas purchases from Russia by 30% on different time horizons. This means that only 70% of the Russian contracted quantity will be delivered to Europe. The modelled length of the "embargo" is 3, 6 and 12 months.

The results are presented with and without the new Polish LNG terminal and the Slovakian-Hungarian interconnector (*Table 4*).

The longer an embargo situation lasts, the higher the costs that CEE customers are forced to pay. Average yearly prices of the region might be up to 30-60 €/MWh, that is an 18-105% relative price increase. The same effect of the new Slovakian-Hungarian interconnector as in the January 2015 scenarios is visible: connecting CEE to the Western European market redistributes the costs of the embargo among the European states more evenly, however still far from equal. A one year embargo would affect even Spain (4% price increase) which remained in the less serious scenarios untouched due to its relative isolation and good LNG connectivity. Most Western European member states would suffer close to a 10% price increase.

Table 4 **Wholesale price effect/loss of load in CEE by a 30% embargo on Russian natural gas exports to the EU for different time periods (2014-15)**

	Length of embargo	Reference price	CEE Regional average price in an embargo situation	Price change relative to reference	Loss of load	Demand served
		€/MWh	€/MWh	%	mcm	%
Without SK-HU and PL LNG	3 months	27	34.3	27.0	2987	67.2
	6 months	26.8	39	45.5	7822	51.0
	9 months	28.9	59.4	105.5	27690	30.5
		€/MWh	€/MWh	%	mcm	%
With SK-HU and PL LNG	3 months	27	31.9	17.8	2736	70.4
	6 months	26.8	33.4	24.6	7127	57.2
	12 months	28.9	50.6	75.1	28644	37

[7] *On their meeting on March 20-21, the leaders of EU member states concluded that, "The European Council is concerned about Europe's high energy dependency rates, especially on gas, and calls for intensifying efforts to reduce them, especially in the most dependent member states."*

Table 5 **Spot LNG flows to Europe in different embargo scenarios**

	Length of embargo	Spot LNG flow in reference	Spot LNG flow	Increase in spot LNG flow	Country of origin	Destination
		TWH	TWh	%		
Without SK-HU and PL LNG	3 months	4	5	25	NO	ES, GR, PT
	6 months	6	9	50	NO	ES, GR, PT
	12 months	24	69	188	NG, NO, EG	ES, GR, IT, PT, UK
		TWh	TWh	%		
With SK-HU and PL LNG	3 months	4	7	75	NO	PL, PT, GR, ES
	6 months	6	11	83	NO	PL, PT, GR, ES
	12 months	24	82	242	NG, NO, EG	ES, GR, IT, PT, UK

Table 5 indicates the growth of spot LNG deliveries in the different embargo scenarios. The Polish LNG is served in all cases only by Norwegian spot LNG (above its long term contract from Qatar). In the 3 month embargo scenario, a third of the total EU spot LNG is shipped from Norway to Poland. As the embargo persists and the gas price in Western Europe grows higher, LNG from larger distances becomes competitive, first from Egypt (EG) to Greece (GR) and then from Nigeria (NG).

An important lesson of the modelling is that improved interconnectivity (Slovakian-Hungarian interconnector) eliminates extreme price differences among EU regions and additional LNG shipments can more easily reach the CEE markets. By this interconnector Hungary has done a lot to improve the security conditions of the country. The vulnerability of the country for Russian gas supply however still remains, and a diversified supply portfolio – be that Middle East, shale gas or LNG source – is essential. Unfortunately decisions on these measures are mostly beyond the sole Hungarian jurisdiction, and little progress has been achieved in the last 10 years.

Overcoming preliminary challenges to shale gas in Europe

The advent of commercial shale gas production in the EU remains in question, owing to widespread environmental opposition, uncertain geology, and excessive bureaucracy at the state level. While hydraulic fracturing or "fracking," the technique required for the extraction of unconventional hydrocarbon deposits has drawn the ire of environmental groups and local communities across the EU, the noise has not prevented determined Member States from pursuing a path towards eventual shale exploitation.

Commission allows Member States to forge path

EU institutions have acknowledged that current directives governing conventional hydrocarbon E&P are inadequate for the unique environmental challenges associated with fracking, but they have refrained from imposing additional regulation with one exception. In October 2013, the European Parliament voted in favor of mandatory environmental impact assessments (EIA) and full public disclosure and consultation for all unconventional wells (pending approval from the European Council). However, this merely corrects a loophole in existing EU legislation which requires an EIA for natural gas wells exceeding 500,000 cubic meters per day. Due to the production techniques employed, unconventional wells typically yield less than this and thus would otherwise not fall under the provision. The most recent statement from the Commission was a set of non-binding recommendations released in January, which allow for an 18 month period before their adoption is reviewed.

The latest declaration was welcomed by pro-shale industry and lobbyists as a victory for energy independence in Europe. For now the Commission is not interfering with a Member States' right to determine their own unconventional policy, but it has voiced its concerns over policy gaps and laid down guidelines which it expects to be adopted. The reality is that the Commission is taking a wait-and-see approach that allows pro-shale governments to conform to best-practices at their own pace. Environmental and public health concerns will likely become more acute as development advances from exploration to production, but shale exploration is still in its infancy and commercial activities are not expected for some 10-15 years.

Member States working to reform hydrocarbon laws and attract investment

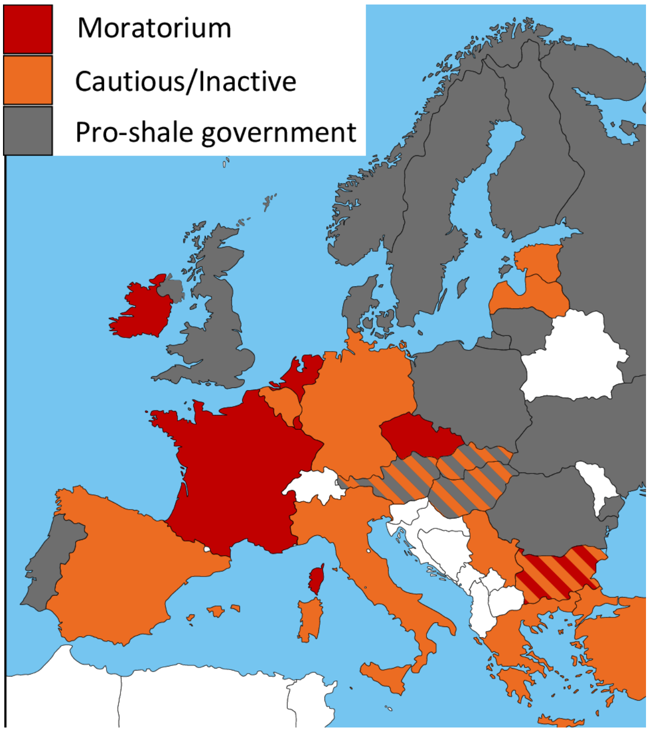
There are various estimates of technically recoverable unconventional resources across Europe, and the truth is no one is sure how viable the formations are until more exploratory wells are drilled. The EIA has released the most optimistic collection of data while other sources such as the USGS and national-based organizations are much more conservative. Yet for governments seeking to capitalize on this potential even the early exploration and data gathering phase has been fraught with challenges and slow to unfold. Part of the overarching malaise is due to fierce anti-fracking environmental campaigns that have successfully brought overwhelming negative attention to the issue. This gives the DG Environment more clout and makes fracking politically unfeasible in some countries (*Table 6*).

But there is usually a correlation between a government's energy security and its position on unconventional extraction, that more of the former leads to a more cautious approach in the latter. Governments that enjoy a public mandate are still unable to accelerate the process because of the prominent role of the state in the industry, which causes massive delays and investment uncertainty. In the US, the federal government is virtually absent from arrangements between companies and private land owners, which paved the way for rapid development of the shale industry. The state ownership of underground resources in Europe leads to above ground problems; more cumbersome oversight, higher effective tax rates and expectations for involvement of local companies, all of which deter crucial foreign investment and expertise. Both the UK and Romania have extensive drilling experience and the requisite regulatory framework that goes with it. Poland, conversely, as a traditional coal producer has no such prior experience in upstream activities. It has faced major challenges recalibrating its regulatory framework, licensing and certification procedures, and tax policy.

Table 6 **Shale gas resources in Europe**

	Poland	United Kingdom	Carpathian Basin (Romania, Hungary, Bulgaria)	France	Germany
Estimated recoverable resources: Shale Gas (EIA)	4100 bcm	707 bcm	538 bcm	3800 bcm	481 bcm

Figure 17 **Attitudes of EU member states to shale gas**



Source: REKK collection

A number of European governments have temporarily suspended unconventional test well drilling in the past few years due to public pressure, while the UK and Romania have recently overturned their suspensions, and others have are simply not pushing forward. Where public opposition remains strong and energy security is fairly robust (e.g. France, Germany, Czech Republic, Ireland) moratoria or inaction prevail pending further studies. Romania, on the other hand, which produces over 50% of its gas and has faced bitter local opposition in Pungesti, the location of Chevron's potential well site, is allowing the company to move forward with exploratory drilling for shale gas. In Poland and Lithuania there is heightened concern over energy security and dependence on imported Russian gas, so the perception of shale gas as an opportunity for energy independence resonates with the public. A recent poll by the Polish Public Opinion Centre found that 73% of respondents support extractions from shale formations even if it were near their place of residency. The UK houses the most dynamic wholesale trading platform in Europe served by a variety of producers, but replacing declining production in the North Sea with a cheap indigenous source as opposed to more expensive LNG is attractive from the government's perspective (*Figure 17*).

Indeed the British, Polish and Romanian governments have emerged as first movers, determined to encourage investment and foster shale development in their territory. In the UK, the moratorium was lifted in 2012 and gave way to a more comprehensive regulatory regime under DECC. The Commons Select Committee carried out a detailed study that concluded there was no evidence that hydraulic fracturing poses a direct risk to water aquifers so long as the well-casing is intact. The government announced consultations on modifying the existing licensing regime to support particular characteristics of shale gas developments, and in December 2013 announced an effective tax rate for shale that claimed to be the friendliest in Europe. Furthermore, industry formally committed to sharing 1% of revenues with the local community in order to gain their support.

Polish regulations have been confusing and largely inadequate for the proper development of the hydrocarbon industry. Bureaucracy is prevalent throughout, but most evident in the prohibitively inefficient certification and licensing procedure that involve several permitting agencies and multiple ministries that mostly do not themselves understand the proper methodology. Poland also employs notable protectionist policies favoring Polish companies and restricting foreign firms entering the market, whereby equipment originating outside the EU must meet strict certification standards and North American workers can take well over a year to certify. The government had proposed a government entity, the National Mining Resources Operator (NOKE), which would take up to a 5% mandatory stake in the expenses and profits of all upstream projects to ensure government oversight, but industry backlash effectively forced the government to capitulate in its latest draft legislation. Amendments to the Geological and Mining Law were submitted to Parliament March 2014 aiming to improve many shortcomings: streamline concessions for prospecting, exploration, and production; dismiss the previously introduced NOKE stakeholder group; guarantee that an exploration concession will grant the right to a subsequent production concession without a tendering process; reformulate the shale gas tax policy so that it totals no more than 40%. Polish legislation has consistently tried to guarantee state control over the sector, so even with changes to critical laws a residual trend in this direction can be expected.

Poland's regulatory framework remains far behind the UK and Romania in meeting standards that appeal to international oil companies, but the limited geological discoveries across the territory have also been lackluster thus far. Assuming that at some point the amendments are adopted and companies find encouraging sweet spots in the sediments, there will also need to be major infrastructure investments, both locally and possibly to facilitate export. Combined these challenges are daunting, and not surprisingly a number of IOCs have withdrawn from Poland in the past few years, frustrated with legal and regulatory shortcomings and disappointed with well results – ExxonMobil, Talisman and Marathon Oil, Eni and most recently Total. For now, the biggest problem has been the government's persistent involvement and restrictions on foreign workers, equipment and technology that are crucial for transposing drilling and simulation techniques to unlock the troublesome geology find scalable well areas. It remains to be seen whether Warsaw can deliver legislation that can deliver regulatory predictability and provide confidence to investors.

Not a magic bullet

The EU must balance the interests of Member States seeking to reap economic and energy security benefits from shale extraction with the management of legitimate environmental concerns. For now the Commission has identified regulatory gaps and issued non-binding recommendations so that Member States can adapt to them incrementally over the next year and a half before further review. The EU is essentially ambivalent while this unfolds in the early stages. As intensity of production increases, it can be expected that the function of the Commission and the behavior of Member States will clash more often.

The process for exploration and production will unfold much slower than in the US and at a much higher cost, not only due to state land ownership and dominance of the sector but also with respect to commercial considerations such as lack of infrastructure, rigs and drilling equipment. The geology will be more problematic also, requiring the expertise of experienced North American service companies that will need a clear path to certification to find new solutions efficiently. Given deeper geological layers, stricter regulations, higher tax rates and a less competitive gas service sector shale extraction in Europe will be far more expensive than in the US – twice as much by some estimates.

Besides incentivizing long-term sustainable investment governments must also manage galvanized local opposition, perhaps following the British example or going beyond. It is clear that there needs to be more responsive dialogue and a credible exchange of factual information with concerned citizens. However the simmering discontent across European localities that will be exposed to developments might require more financial incentives. In the US landowners typically receive upwards of 25% from the drilling companies, whereas this money essentially goes straight to the central government in Europe. The 1% concession in the case of the UK seems paltry by comparison.

When aggregate commercial production eventually does occur in Europe, the most optimistic IEA projections are that shale gas will mitigate the EU's declining conventional production and stabilize import dependency at the current level of 60-65% by 2035. This is likely the best case scenario. The price impact could be significant depending on the costs and volumes and tradability across Europe's gas grid, but it must compete with pipelined gas and LNG to be successful. At the least it would provide an alternative source of competitively priced gas which factors prominently into the EUs vision of energy security. But it is important to temper expectations as to the transformative potential of shale gas in the EU – ultimately it will not emulate the success of the US or solve any of Europe's energy challenges on its own.

The status of smart electricity grids in Europe

In order to accomplish the 2020 GHG emission and renewable energy use targets of the European Commission[1], the large scale development of the European electricity network is indispensable. This development is more than mere network enlargement, it also incorporates the establishment of a modern network and metering infrastructure that enables, among others, the integration of large numbers of renewable/decentralised generating units and electric vehicles, facilitates consumer side energy efficiency and the reduction of network loss, real time metering and market based pricing.

According to Directive 2009/72/EC, regulating the internal market of electricity, modernisation of distribution networks should take place "in a way that encourages decentralised generation and energy efficiency", an important tool of which is the introduction of smart grids.

The Directive declares that the introduction of intelligent metering systems is the task of the member states. Since the rationality of the introduction of smart metering systems may differ by member states, the Directive obliged member states to carry out a cost-benefit analysis with an initial deadline of 3 September 2012. If the result of this cost-benefit analysis is positive in a given country, then by 2020 at least 80% of the consumers of the country should be equipped with smart meters.

The smart grid concept

Smart grids can be best defined by the functions they provide. According to the European Commission these are electricity networks that can intelligently integrate the activity of their customers to ensure sustainable, economic and secure electricity services. A smart grid consists primarily of intelligent network monitoring, control and communication, and it employs innovative products and services. Smart networks may pursue the following goals:

- large scale network integration of renewable based and small power plants,
- enhanced applicability of demand side management,
- flexible electricity demand and more conscious energy consumption,
- reduced network loss,
- continued reliability of the electricity system in parallel with the integration of a changed group of network users.

It needs to be emphasized that smart grid is a wider concept than smart metering, with the smart metering infrastructure acting as an essential pillar of smart grids. Similarly to networks, smart meters can also be defined based on the functions they serve. Recommendation 2012/148/EU of the Commission prescribes the functions that a smart meter needs to deliver at the minimum.

According to the 2013 working document[2] of the Commission smart metering systems also provide the basis for demand side flexibility instruments as they generate data of appropriate frequency (measured at intervals of at least 15 minutes) on energy consumption and they offer a standardised user interface that provides information to the consumer on individual consumption, market conditions and the available service and pricing options as well[3]. This on the whole provides incentives to consumers to delay their consumption to periods of lower price (and lower demand), thereby easing the burden falling on the system operator and cutting their own energy bill.

Differing investment strategies

The survey of the Joint Research Centre (JRC) of the European Commission shows that between 2002 and 2014 the 28 member states of the EU, together with Norway and Switzerland altogether spent more than € 3 billion on smart grid pilot projects, including research and development and demonstration projects. Of this, the share of the 11 Central and Eastern European countries[4] reached € 137 million. With respect to the level of investment in smart grid solutions and the actual target of the investments we can observe massive differences among individual countries. *Figure 18* below depicts the cumulative investment to smart grid solutions for each country, as well as the distribution of investments among project types.

Unsurprisingly, the pioneering countries are in Western and Northern Europe. Compared to the size of the country, Denmark exhibits an outstanding level of investment (in excess of € 200 million). Likewise, we can observe that the weight of project types substantially differs across countries. While in the United Kingdom and Belgium, for example, the bulk

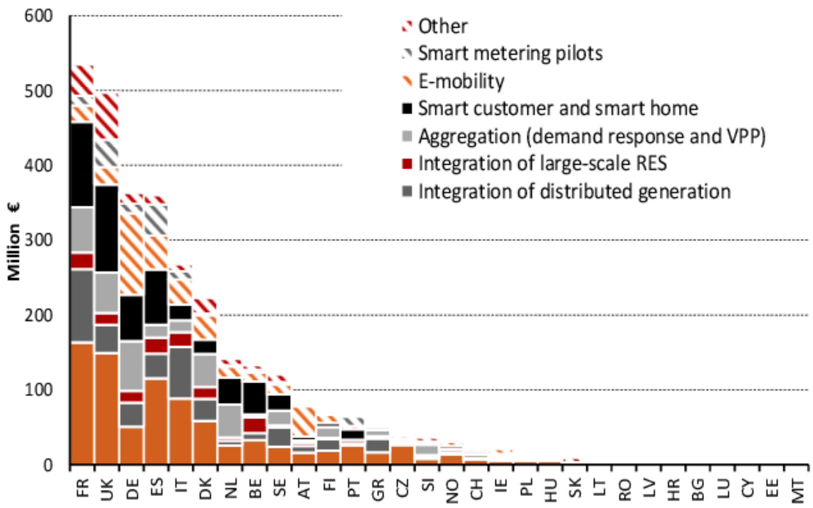
[1] A 20% reduction in greenhouse gas emissions compared to the 1990 level, a 20% reduction of energy use and a 20% share of renewable energy sources within total energy consumption.

[2] Commission Staff Working Document (2013) 442 final on incorporating demand side flexibility in electricity markets.

[3] In accord with Recommendation 2012/148/EU this is equivalent to consumption metering at least every 15 minutes.

[4] Poland, Czech Republic, Slovakia, Hungary, Bulgaria, Romania, Slovenia, Croatia, Latvia, Lithuania and Estonia.

Figure 18 **Smart grid investments in Europe according to country and project type, 2002-2014, million €**



Source: JRC

of the investments focus on consumers and intelligent homes, in France most attention has been devoted to the network integration of decentralised generation, while almost all of the investments in the Czech Republic have been directed to network operation. This clearly shows that not only the importance of smart grids is perceived differently by different countries, but also the areas of focus.

As revealed by the JRC survey, 80% of European smart grid projects have received state aid, while only 45% of the total investment costs have been financed by the private sector. We should keep in mind, however, that the programmes in question are pilot and R&D initiatives, for which the increased role of state resources is not at all surprising. In contrast, the burden of financing the future investments is likely to fall mainly on the distribution companies, since the smart grid infrastructure requires the largest and most comprehensive investments in the case of distribution networks.

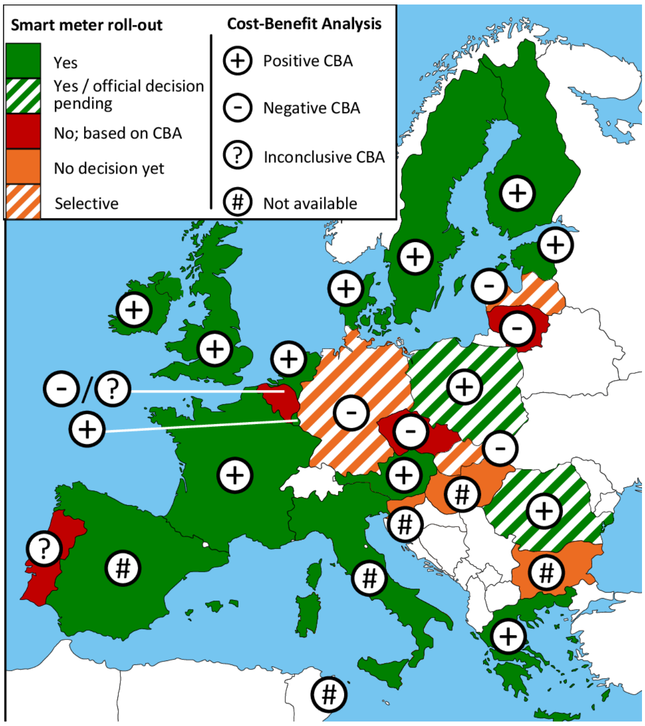
Nonetheless, most projects have been lead not by government organisations, but energy companies and DSOs, or universities, consulting companies and research centres. With respect to the role of TSOs, DSOs and energy companies the Austrian and French examples are certainly relevant: in both countries consortia formed primarily by these companies participated in the development of plans on the practical implementation of smart grids. In other countries, such as the United Kingdom and Ireland, industrial actors from a wider spectrum have been involved in developing the national smart grid strategy.

Costs and benefits

Even though with respect to smart grids member states are affected by European regulation only indirectly (there is no obligation, only recommendation, and network modernisation of this kind is driven by renewable targets), each member state is obliged to carry out an economic analysis of the introduction of smart metering, and in case of a positive outcome, smart meters have to be installed in large numbers. The status and result of these cost-benefit analyses is described by *Figure 19* below.

Altogether 16 member states decided on the large scale installation of smart meters, equal to about 72% of EU27 consumers. The cost-benefit analyses in Poland and Romania also resulted in a positive outcome, but an official decision has not been made yet. In case of Belgium, Lithuania and the Czech Republic the result is negative. Germany, Latvia and Slovakia have opted for the selective installation of smart meters, as the cost of an all embracing meter replacement program exceeds expected benefits. Bulgaria, Cyprus, Hungary and Slovenia had not submitted their cost-benefit analyses until July 2013. In December 2013 Hungary remedied its prior negligence.

Figure 19 **The status of cost-benefit analyses of smart electricity grids in Europe**



Source: European Commission, 2014[5]

[5] *COMMISSION STAFF WORKING DOCUMENT, Cost-benefit analyses & state of play of smart metering deployment in the EU-27, SWD(2014) 189 final*

The 2013 German cost-benefit analysis is quite educational. One of the main conclusions is that the energy savings harvested by final consumers and the realignment of consumption alone cannot offset the costs of implementing and operating the smart metering system. If, in line with the notion of the European Commission, 80% of the consumers were to be equipped with smart meters by 2022, the system would need to be financed through higher charges for system use. In this case, however, most of the burden would fall on final consumers that do not directly benefit from smart meters. Therefore the German regulation considers the installation of smart meters as justified only where the generated benefits are highest (generating substantial savings of energy or shifts in consumption, or significantly improving the efficiency of the electricity network), while financing the network would be assigned to its key beneficiaries.

The case of the Czech Republic serves as an interesting example, with the result of the cost-benefit analysis turning out to be negative - based on which the widespread installation of the smart metering system is not planned before 2018. The main driver of the negative result is that compared to the dual tariff scheme that has long been used in the Czech Republic – and is also present in a number of other Central and Eastern European countries – smart metering would not generate sufficient additional benefits to assure financial viability. At the same time the Czech analysis also revealed that the investment costs of the scheme are too high, while based on the pilot projects the price elasticity of consumption is too low for the wide scale introduction of smart meters to be profitable. The Czech case offers a dual lesson: on the one hand it shows that in case of a low price elasticity of demand smart meters do not trigger a large enough shift in consumption to make their widespread introduction financially attractive. On the other hand it also tells us that existing time period based metering systems – that are, nevertheless, not in compliance with the smart metering requirements of the already mentioned Commission recommendation 2012/148/EU – may be referenced by regulators as justification to postpone smart metering investments.

Regulatory challenges

Even if there is regulatory ambition to implement smart meters and grids, motivating distribution companies raises major questions. Whether we discuss smart metering systems, or more generally smart grids, the largest investment costs are expected to fall on DSOs: innovative network solutions are not only more expensive than traditional network development, their financial return is also more risky, since the related benefits are more difficult to forecast. The recent REKK survey covering a number of Central and Eastern European countries as well as Germany and Austria also concluded that the proliferation of smart grids is hindered mostly by large investment costs, inappropriate incentives and the lack of regulatory initiatives[6]. Survey responses almost uniformly pronounced the development of a proper incentive system for investments as the most important task of regulatory authorities.

The case of Italy offers a number of lessons. Here the high ratio of weather dependent photovoltaic generation has required large scale network development for the last few years. As a response to the large demand for investments, the Italian regulator (AEEG) made it possible for distribution companies to apply for additional support to finance their smart grid related demonstration projects. When determining the support for the projects selected by a board of independent experts, the regulator employs a weighted average cost of capital (WACC) that is 2% higher than usual for a period of 12 years following the launch of the investment. To be supported, projects have to meet a number of criteria and the final score is also established by a number of factors: of these most weight is given to the degree to which the investment increases the volume of weather dependent renewable generating capacities that can be integrated into the grid. The largest distributor company, ENEL, also used these sources of support to finance its programs that contained smart grid elements and targeted the integration of photovoltaic and wind power generation in four regions of South Italy. In addition to incentive support, research and development can also be supported in Italy. This source of funding is available for research institutes, universities and distribution companies alike and it is financed through network tariffs.

Smart grids in Hungary

At present in Hungary there are a number of on-going smart metering pilot projects. Of the distributing companies, ELMŰ-ÉMÁSZ, DÉMÁSZ and E.ON all carry out such projects, with a dual purpose: they strive to investigate the feasibility of the smart metering technology, while also assessing the impact on consumption. Currently the analysis and evaluation of the technical aspects of metering is in a more advanced stage, the collection and analysis of consumption data will gradually take place during 2014-2015. Importantly, these projects also test the so called multi-utility solutions, that is, how smart electricity, gas and possibly water meters could be integrated in a uniform system. The implementation of the largest smart grid and metering project, the Intelligent Household Pilot Project of MAVIR, involving over 200 thousand households, will start this year and could be completed next year at the earliest. As a result of the exemption of Hungary's electricity sector from the requirement to auction carbon-dioxide credits (EUAs), the project is financed from the freely allocated allowances, thus Hungary will be obliged to report the results to the European Commission.

The preliminary cost-benefit analysis prepared for the Energy Office in 2010 indicated net benefits and recommended a 2013 target date for the finalisation of the pilot projects, to be followed by the large scale installation of the smart metering system in 2014[7]. The analysis assumed that the bulk of the domestic benefit of smart metering would comprise of the 70% decline in electricity theft, 20% lower network losses and a 90% cut of bad debts. It is worth noting that while the calculations of the study indicate positive social net benefits for the long run assuming the quick penetration of smart metering, the net present value of the investment for sector participants would be undoubtedly negative.

The newest Hungarian cost-benefit analysis of June 2013 – still not intended as the final one – reaffirms that the issue of investment financing is also vital for Hungary[8]. This more recent analysis attempted to quantify the costs and benefits of four distinct scenarios:

1. Independent distributor model: Under this scenario the study assumed that in accord with the requirements of the EU by 2021 smart metering will be introduced at 80% of the consumers. The installation, operation and financing of the system is the responsibility of the individual DSOs. Currently this scenario is the basis for the smart grid pilot projects of the domestic distributor companies.
2. Common distributor model: Similarly to the previous scenario the responsibility is retained by the DSOs, but the distributor companies implement and finance the necessary investments together, and this is expected to generate cost savings compared to individual implementation. The central smart meter operator appears as a new piece of this system, and it can operate either as an independent company or as a common subsidiary of the distributors. An important advantage of common implementation is that switching the service provider becomes easier for consumers.
3. MAVIR-model: Under this scenario the central meter operator is owned by MAVIR, just as the burden of financing smart metering investments also falls on MAVIR.
4. MAVIR-model with DSM: The previous scenario is supplemented with demand side management (DSM) that includes, among others, a dynamic, market based final consumer tariff. Installation of the DSM infrastructure is the responsibility of the so called active savings power plant, which is in fact the energy trading firm that aggregates the savings of the final consumers. Models 3 and 4 together represent the basis for the on-going smart grid pilot project of MAVIR.

The conclusion of the analysis is that the net present value of scenario 4 (MAVIR model with DSM, the scenario with the highest investment and operating cost) is clearly positive, while in case of scenarios 2 and 3 the sign of the result depends on the assumptions. The independent distributor model does not seem to be cost-effective. The calculations demonstrate that the joint introduction of smart electricity and natural gas meters is expected to generate additional gains. The study, nevertheless, states that due to the uncertainties surrounding the calculations it would be worth to repeat the analysis later on, building on the experience of the currently executed pilot project. This is also the position officially represented by Hungary toward the Commission.

[6] *The results of the survey are available in the REKK study „Smart Grid in the Danube Region Countries – An Assessment Report" (www.rekk.eu).*
[7] *AT Kearney, Force Motrice: Assessment of smart metering models: the case of Hungary, Improved final report, 2010*
[8] *Energlobe Service Ltd: The feasibility of smart metering in Hungary, 2013*

The nightfall of the obligatory purchase regime

The guideline of the European Commission on State aid for environmental protection and energy – recommendations on renewable energy support schemes

The European Commission introduced its guidelines on state aid for environmental protection and energy in its Communication C(2014) 2322. The document is a revised, updated version of a similar guideline from 2008, supplemented with recommendations on state aid within the energy sector[1]. Even though the guidelines are not obligatory, member states still have a strong interest to follow the rules defined by the communication, as the Commission – which has exclusive powers in the field of competitive policy, and within that state aid – acts based on these rules when it evaluates the state aid related decisions of the member states.

The purpose of the guideline is to foster the evolution of subsidy schemes that facilitate the accomplishment of targets related to environmental protection and the utilisation of sustainable energy sources without distorting internal market competition. It takes account of those types of aid that – meeting specific conditions set forth by the regulation - can be made compatible with the proper operation of the internal market of the EU[2]. At the same time it also reveals those forms of aid the application of which would most likely trigger a case under competition law and repeal the corresponding measure. According to the guideline, state aid is in conformity with the internal market if

- it serves objectives of common interest, supports a competitive, sustainable and safely operating energy system
- it promotes a development of significant proportions that could not be achieved under pure market conditions (e.g. due to the differing interests of those with stakes in the investment)
- other regulatory instruments would not be sufficient to reach the positive impact in question
- it provides incentives for competitive behaviour
- it is proportional, that is, the aid is not more than the minimum required to reach the objective
- it does not adversely effect competition and trade among member states, and any negative impact is counterbalanced by the positive contribution to a competitive, sustainable and secure energy system
- it is transparent, in other words, information on the circumstances of the awarded aid is easily accessible to all.

The communication, thus, sets specific rules pertaining to those types of aid for environmental protection and energy generation that are judged by the Commission as compatible with the internal market under certain conditions. Measures related to the energy sector include the investment and operating support of renewable projects, aid to assist measures targeting energy efficiency, support to carbon capture, transport and storage (CCS), aid to the infrastructural development of the energy sector and supporting measures ensuring the appropriate generation adequacy of electricity producing capacities.

In our article we introduce the requirements related to the development of systems supporting renewable based energy generation. In our previous issue we reported that in several member states the application of too generous and inflexible renewable support schemes resulted in an unexpected acceleration of investment activity and the subsequent rise of financing needs and consumer burden, requiring the adjustment of the support regimes[3]. As the feed-in tariff (FIT) support systems – also in force in most EU countries today – ensured predictable and safe returns, they have had a major role in the development of renewable technologies, and the increasing market share and declining cost of these technologies. With the advance of renewable energy generation, however, the sector encountered new challenges (e.g. low, sometimes negative wholesale prices, rising costs of balancing and network development) as a result of which there is an increased need for renewable electricity producers to make their investment and operating decisions with a view on the needs of the market. Inflexible incentives may lead to market distortions, while due to the increasing interconnectivity of energy markets national measures also impact the markets of other

1 Community Guidelines on State Aid for Environmental Protection, (2008/c 82/01)

2 The revised General Block Exemption Regulation (GBER, C(2014) 3292/3), adopted in May 2014, determines the so called general compatibility conditions based on the experience of the Commission. If state aid in a specific area of regulation (e.g. environmental protection) complies with these conditions, then the Commission forgoes its hitherto exclusive right to preliminary inspection and approval of aid and transfers this competence to the Member States.

3 REKK Hungarian Energy Market Report, p. 28, vol. 1/2014 countries. An ex-post regulatory correction, on the other hand, may negatively impact investor confidence.

The rules specified in the guidelines

The recommendations specified in the communication apply to the period 2014-2020, but the Commission assumes that the renewable electricity generating units newly created between 2020 and 2030 will reach the level of network parity – that is, they will be in a position to supply their generated electricity at a price at which they already become competitive without any support. Accordingly, the gradual reduction of the support provided to renewable producers is viewed as indispensable, ensuring a smooth transition to cost efficient energy generation based on market mechanisms. According to the communication the most appropriate method of awarding support is through auctions or competition, during which the producers capable of supplying renewable energy at the lowest cost are selected, automatically ensuring that support is kept to a minimum and can be gradually ceased. All enterprises that operate within the territory of the European Economic Area and the European Energy Community should be granted similar access to the auctions.

According to the communication during the interim period of 2015-2016 the support to at least 5% of the planned new renewable capacity has to be awarded through auction, while after 1 January 2017 any support can only be provided via auction. A member state can make an exemption from this rule if it provides sufficient evidence that a) only one, or a restricted number of projects or project sites would be eligible for the support; b) the auction would result in an excessively high price (e.g. there is a risk of strategic collusion); c) the number of realised projects and the volume of newly created capacity would be too low. In order to be able to consider the differing technical maturity of different renewable based electricity generating technologies, the guideline allows member states to launch technology specific auctions.

Since larger installations relying on economies of scale are likely to be more successful at auctions, small scale projects may be exempted from the obligation to compete. Projects with a capacity of not more than 1 MW (6 MW or 6 operating units in case of wind power plants) may be supported without an auction. Demonstration projects are also exempted.

Based on the guideline, as of 1 January 2016 renewable electricity support schemes can be regarded as compatible with the internal market if they satisfy the following conditions:

- the electricity is directly sold in the market and the producers receive the support as a premium over the market price
- the beneficiaries bear the balancing cost due to deviation from the schedule
- the measures of the member state ensure that the producers do not have an interest to sell the electricity at negative prices.

The above restrictions do not apply to power plants with a capacity below 500 kW and renewable projects launched for the purpose of demonstration, while in case of wind power installations with a capacity below 3 MW or having not more than 3 generating units are exempted. The support may be received until the installation is fully depreciated in compliance with prevailing accounting rules and investment aid need to be subtracted from operating subsidies. The Commission approves support systems for a period of less than 10 years.

As the Commission would like to promote cooperation mechanisms in order to make renewable production as efficient as possible, it awards a favourable evaluation for those state aid schemes which are also available for installations outside the country in question, but inside the European Economic Area or the Energy Community.

Support to renewable energy generation the purpose of which is not electricity production is judged by the Commission as compatible with the internal market if the support provided to renewable based energy does not exceed the difference between the levelized cost of energy (LCOE) and the market price of energy. Normal return on capital can be used to determine the levelized cost, but the investment support has to be subtracted from the investment cost used for the calculation. The calculation has to be repeated at least annually using revised cost factors and support can be provided only as long as the generating unit has not yet been fully depreciated in compliance with the accounting regulations in force.

Since, as opposed to most renewable energy producing technologies, biomass fired power plants are characterised by relatively low investment and high operating costs, in the absence of external support fully depreciated power plants may decide to shut down or switch to fossil fuels. In order to maintain renewable generation the Commission may consider the aid to biomass fuelled power plants after they are fully depreciated as compatible with the internal market if the Member State proves that the average cost of the facility exceeds the market price and the use of biomass is more expensive than the combustion of fossil fuels. As a precondition, the communication requires that only energy based on a renewable source can be supported, and only the difference between the operating costs and the market price (or the price of the alternative fossil fuel) can be compensated. As an additional stipulation the authority needs to keep monitoring the costs of production, and adjust the level of the aid if needed.

Member States may also decide to introduce a green certificate system if they prove that the operation of the support scheme is essential in ensuring the viability of renewable energy sources, the system – possibly differentiated by technologies (providing different quantities of green certificates) – does not result in excessive subsidies, and the scheme provides incentives for renewable electricity producers to act in a competitive manner.

The guidelines and the Hungarian regulation

The Hungarian purchase obligation regime contains a number of provisions that, from a certain perspective, can be viewed as more advanced than other FIT regimes: tendering as a condition to awarding support for wind energy investments has already been passed on a regulatory level[4] (nevertheless, an actual tendering procedure has not yet taken place), renewable producers are responsible – though under more favourable conditions than conventional power plants – for deviation from schedule and they are also obliged to maintain schedule, while feed-in tariffs are differentiated by the time of the day, except for solar and wind power[5]. The Hungarian regime cannot be accused of excessive generosity either, feed-in tariffs are among the lowest in Europe[6]. In addition, the feed-in tariffs for different technologies only slightly differ. Therefore, with respect to its design, the Hungarian support regime would promote a more efficient allocation of resources. Its effectiveness, however, has not been proven in practice: at present Hungary lags behind the targets declared in its National Renewable Energy Action Plan. This is probably explained partly by the low level of feed-in tariffs, and partly by the uncertain investing atmosphere driven by the delay of the new regulation, but it may also be associated with the misguided – but later corrected – support policy under which large scale co-firing of biomass was first encouraged, then excluded from the technologies eligible for FIT[7].

The publication of the communication, nevertheless, makes one hopeful with respect to the near-term adoption of the new support regime which should be able to promote the development of large scale new capacities, enabling the return to the development path indicated within the renewable action plan. The regulatory options, however, have narrowed: instead of the guaranteed purchase of the FIT regime, decision makers can consider either premium or green certificate systems. The purchase obligation and the fixed purchase price can be made available only for the previously mentioned exceptions (small scale installations constructed for demonstration purposes).

An interesting decision with respect to tendering is whether it should be technology specific or technology neutral. By amending the regulations, one of the goals of the EU has been the promotion of competition among technologies as well, that is, European resource allocation should turn out to be as efficient as possible with regard to the territorial distribution of both resources and investments. Specific national targets, however, are in contradiction with this goal. For instance, as a result of its 2020 renewable electricity target of 35%, and 2030 target of 50%, Germany starts to make use of increasingly expensive technologies, in particular encouraging e.g. the utilisation of off-shore wind power and geothermal energy, and does not foresee the application of cooperation mechanisms[8]. The degree to which individual member states will escape technology neutral auctions – citing the possible exceptions contained by the guidance – should be interesting to see. As we already mentioned, so far the Hungarian system has not really differentiated among technologies.

As a positive impact, tendering provides information on the current cost of technologies and its application usually results in declining prices[9]. It also provides an opportunity to control the volume of installed capacities and the budget, and ideally it leads to the selection of the most efficient participants with a dedication for the long run. As a result, the consolidation of the sector is expected by market participants[10].Tender based systems can, however, also

[4] *33/2009. Decree of the Ministry of Transport, Telecommunication and Energy*
[5] *389/2007. Government Decree*
[6] *REKK (2013) Renewable Electricity Market Monitoring in the Countries of the Danube Region*
[7] *For our article on this topic see p. 12 of Vol 3/2013 of the REKK Hungarian Energy Market Report*
[8] *EEG, REKK (2013) Renewable Electricity Market Monitoring in the Countries of the Danube Region*
[9] *Irena (2013) Renewable Energy Auctions in Developing Countries*
[10] *see e.g. http://hvg.hu/kkv/20140528_Nincs_tobb_mellebeszeles__Brusszel_ujras [in Hungarian]*

have drawbacks: they may favour participants with more market power and there is a risk that bidders offering excessively low prices are selected and they demand ex-post support to offset their uncovered costs. In order to reduce risks, the regulation needs to be developed with care, for which practical international examples are available.

Based on data from the end of 2012 existing capacities need to double by 2020 within the Danube region in order for the countries to meet their renewable targets[11]. With the introduction of the new system investors need to take on market risk as well, and it will be interesting to see how much premium they will demand in exchange for the installation of new capacities, and how market prices – including also the premium resulting from tendering – will compare to the current FIT in selected EU countries. On top of the level of the premium, the administrative constraints and burden are also essential from the perspective of investment incentives[12], therefore the simplification of permitting and tendering procedures may also substantially contribute to the increase of renewable capacities.

[11] *REKK (2013) Renewable Electricity Market Monitoring in the Countries of the Danube Region*
[12] *ERRA-REKK (2011) Tariff and Pricing Committee Issue Paper: Renewable Support Schemes for Electricity Produced from Renewable Energy Sources*

The major economic impacts of the 2030 European GHG emission reduction target on Hungary

Commissioned by: ECF (European Climate Foundation)

In early 2014, the European Commission published its recommendation for the climate and energy policy frameworks between 2020 and 2030. This study analyses the effects of the abovementioned recommendation to Hungary, focusing on three key areas with high importance from an economic and energy policy point of view:

- Analysing the effects of the various levels of possible European GHG reduction targets on the financial viability of Paks 2 nuclear power station, a priority investment proposed by the Hungarian State. This study analyzes how different ETS quota reduction scenarios would affect the return on the nuclear power plant investment based on simulations of the European Electricity Market Model (EEMM) of REKK.
- Calculating the expected auction revenues of the Hungarian state budget between 2021 and 2030 in case of various ETS quota reduction scenarios.
- Providing an overview of the expected emission levels in sectors under the so-called Effort Sharing Decision (ESD) – i.e. non-ETS sectors – until 2030 for Hungary, and assessing how these relate to the emission reduction obligations of Hungary following various possible implementation scenarios.

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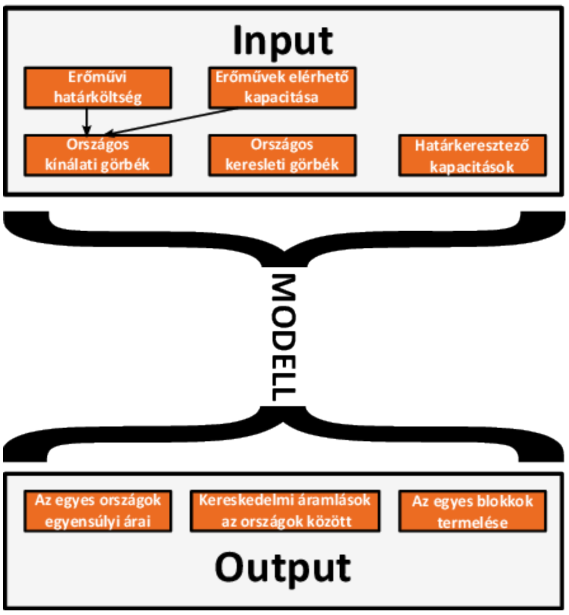
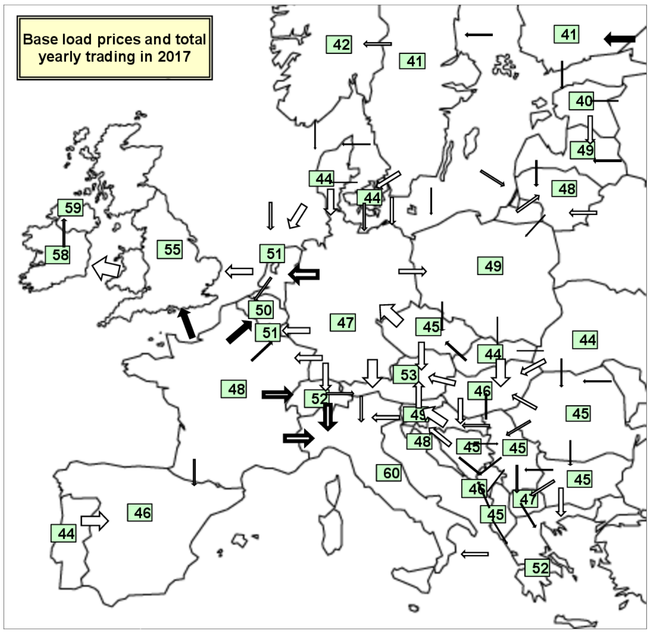
EUROPEAN ELECTRICITY MARKET MODEL (EEMM)

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





ASSUMPTIONS

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

USAGE

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

RESULTS

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

REFERENCES

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

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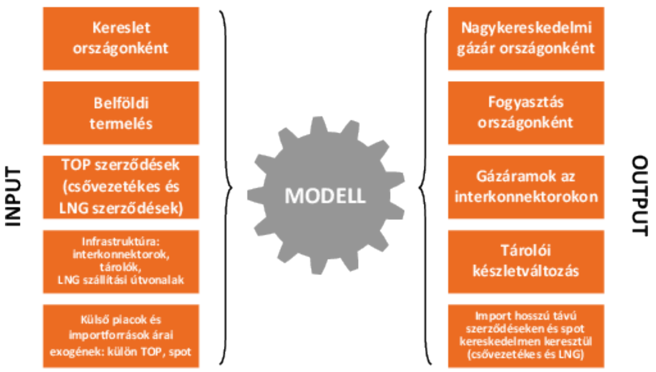
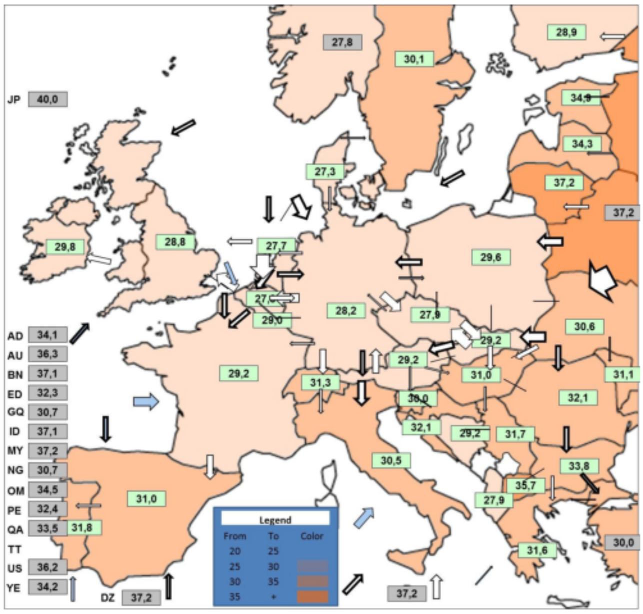
EUROPEAN GAS MARKET MODEL (EGMM)

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





ASSUMPTIONS

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

USAGE

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

RESULTS

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

REFERENCES

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

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