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The Crisis of the European Electricity System

Diagnosis and possible ways forward

Including contributions by
Marc Oliver Bettzüge, Dieter Helm and Fabien Roques

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January 2014

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Foreword

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The European energy system is currently in crisis. By adopting the Climate and Energy Package at the end of 2008, the European Union made strong commitments for 2020: a 20% reduction in EU greenhouse gas emissions from 1990 levels, 20% of EU energy consumption produced from renewable resources and a 20% improvement in the EU's energy efficiency. But these targets were based on misguided assumptions. The expected economic growth made the first commitment a challenging target but it was also supposed to ensure that the deployment of renewable energy sources would be affordable. The expected rise in fossil fuel prices would make renewables profitable and would allow subsidies to be phased out. By paving the way for a climate-friendly economic growth, the European Union had the ambition to become the world leader in renewable energy manufacturing and in the invention of innovative and sustainable ways of life.

For once, the EU strategy was ambitious and comprehensive. But none of its underlying assumptions proved accurate. The financial crisis is partly to blame but so is the US shale gas revolution whose full effects on energy markets have not yet been seen. Besides, the international community is not on track to develop a satisfying response to global warming. The share of electricity generated from coal has been increasing as coal prices went down due to shale gas production (European coal prices fell by 30% between January 2012 and June 2013) and German CO_2 emissions rose in 2012. Moreover, the rise in power of China in the photovoltaic industry has rattled European leadership in renewables, at least partially. Incorrectly adjusted, the EU climate policy has failed to give visibility on carbon price and to provide industrials with a framework conducive to long-term investments.

And yet, electricity prices for households have increased considerably (by 27% between 2008 and 2013). In Germany, they have doubled in ten years and it is now a major political issue there, as well as in Spain.

The Climate and Energy Package is actually the second cornerstone of a common energy policy in the European Union, the first one being the construction of an integrated and liberalised electricity market, initiated in the early nineties. But it is now obvious that both no longer meet their original objectives: security of supply, affordability and sustainability are currently under serious threat.

The massive integration of renewable energies has induced an oversupply situation, has led to a sharp decrease in prices on the wholesale electricity market (which even turn negative sometimes) and eroded the profitability of gas-fired power plants: in EU-27, 12% of gas-fired capacity could close in the next three years. Yet, those plants are needed to ensure load balancing, as the power grid faces sudden flows of intermittent renewable energies. In the same time, important investments are necessary for some old power plants to be renewed; but, many major utilities are in bad financial shape and will have trouble doing it.

It is within this context that the "Commissariat général à la stratégie et à la prospective" (CGSP) was commissioned by the French Prime Minister to conduct an analysis of the situation and to examine the European electricity market's medium-term outlook. CGSP has called on the expertise of three European economists: Marc Oliver Bettzüge, Professor of Economics, Director and Executive Chairman of the Research Institute for Energy Economics at the University of Cologne; Dieter Helm, Professor of energy policy at the University of Oxford, and Fabien Roques, Associate Professor at the University Paris-Dauphine and Vice President at Compass Lexecon. Each of them shared their diagnosis on the current crisis of European electricity markets and made recommendations for change.

In the light of these contributions, which are included in this report, a CGSP team consisting of Dominique Auverlot, Étienne Beeker, Gaëlle Hossie and Aude Rigard-Cerison, joined by Louise Oriol from the French Ministry of Ecology, Sustainable Development and Energy, put forward an analysis and recommendations for short- and long-term action towards a European market for electricity and a sustainable policy framework.

It is essentially, on the one hand, to clarify the objectives of EU energy policy and to ensure their consistency and, on the other hand, to distinguish these objectives from the means used to achieve them. This means in particular that, in the elaboration process of the future climate and energy package, the EU should consider the reduction of CO_2 emissions as the primary – or even unique – objective, energy efficiency and the development of renewables appearing therefore as means to serve that objective.

It is also important to review all policies in favor of renewable energies, by replacing the feed-in tariffs for mature renewable energies by mechanisms more compatible with the market, and by making them take part to the system balancing. In addition to this revision, there is need for a research and development policy for immature technologies that is both ambitious and coordinated at European level (renewable energies, storage, energy efficiency, smart grids).

It is not accidental that the EU has engaged in building up a common climate and energy policy: there are strong synergies in doing so and the gains from successful cooperation are substantial. European nations should therefore act together. In order to do so in an efficient way, the current defects of the European electricity market should be urgently dealt with: this is the thinking behind the proposals contained in this report.

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Introduction

The European internal electricity market was designed in the mid-nineties under the idea that the greater competition enabled by liberalisation will lower electricity prices for end-users, thus benefiting final consumers. In December 2008, the European leaders committed to turn Europe into a highly efficient and low carbon economy and to that end, adopted the Climate change package with its three targets for 2020 (a 20% reduction in EU greenhouse gas emissions from 1990 levels, 20% of EU energy consumption produced from renewable resources and a 20% improvement in the EU's energy efficiency) in a period of optimism: even if the economic crisis had already begun, economic growth was deemed robust enough to enable a fast-paced, yet affordable transition, towards a low carbon energy system and the European Union had the ambition to become the world leader in renewable energy manufacturing and deployment. In order to achieve the renewables target, most Member States introduced renewable energy sources (RES) support schemes “out of the electricity market” through price-based (feed-in tariffs (FiTs), feed-in premiums (FiPs)) or quantity-based mechanisms (green certificates) while granting priority of access and dispatching for RES-sourced electricity plants.

The acute economic crisis which Europe has been undergoing since 2008, and its severe consequences in terms of growth domestic production (GDP) contraction and record-high unemployment rates have swept away those expectations and legitimately placed the focus on enhancing growth and competitiveness under tight financial constraints. In that context, the multiple objectives of the European climate and energy policies lead to complexity and major economic distortions.

The European electricity market is indeed currently in crisis:

– the oversupply situation resulting mostly from the lower electricity demand and the rapid deployment of renewables has led to a sharp decrease in the wholesale electricity prices to the point where many existing generation units are no longer profitable; for example, in Germany, where the installed capacity of wind and solar power is quite significant (around 65 GW and higher than the average power demand), conventional electricity production (and wholesale prices) decreases sharply during windy and sunny weather, but is still needed the rest of time as wind and PV (photovoltaic) electricity production only accounts for 13% of total electricity production;

- simultaneously, electricity prices for end-users whether households or industrial customers, have been increasing as the cost of renewables support schemes is passed on to the consumers through state-imposed levies and taxes and they are now quite high compared to outside Europe;
- the carbon price on the European Union Emission Trading System (EU ETS) has collapsed and is now in the range of 3-5 €/tCO_2 compared to 20-30 €/tCO_2 in 2008. These low prices combined with the decrease in coal prices since 2011 have made coal-fired generation more profitable than gas-fired one: as a result, coal-fired plants have a higher utilisation rate than gas-fired power plants which led CO_2 emissions from power generation to increase in some European countries such as Germany.

As a consequence, the three core objectives of the European energy policy, namely security of supply, affordability and sustainability, are under serious threat:

- the low wholesale market prices, by making many existing generation units no longer profitable, especially gas-fired power plants, have led utilities to close or mothball some of them: the ten largest utilities in Europe have announced the closure of 38 GW of thermal capacity by 2015. In the long run, about 40% of the current thermal capacity is at risk of closure due to economic reasons. Widespread closures would lead to a severe drop in capacity margins which in turn would be worrying from a security of supply point of view;
- the rising electricity bills for both households and industrial consumers are cause for concern: on the one hand, it led to a deep increase in the number of fuel poor in Europe and has been limiting households' disposable income. In Germany, the cumulative total that consumers have spent since 2000 only for subsidizing green energy is set to pass €100 bn this year, and is growing by more than €20 bn every year. In Europe, it was higher than €30 bn in 2012. On the other hand, it widened the gap in competitiveness between European industries and their competitors in other parts of the world, especially in the United States;
- even if the 2020 carbon emissions reduction is nearly reached in the European union (to a large extent because of the crisis and the externalisation of some industrial activities[1]), the current low carbon prices are worrisome as they provide no incentive for investing in carbon mitigation technologies whether switching from coal to gas, implementing CCS or deploying renewables.

This situation may worsen in the future. We have in fact entered two kinds of vicious circles:

- while strong investments are needed in electricity generation to decarbonise the sector and to replace ageing power plants, the wholesale electricity prices are too

(1) A study from the French Minister in charge of Ecology dated November 2013 shows that, if CO_2 emissions has lowered by 7% on the territory, the consumption of CO_2 has increased by 14.2%, when taking into account the content in CO_2 of imported products.

low to attract the required investments; and, moreover, the electricity sector is no longer seen as profitable, inducing higher cost of capital, and, in the long term, higher prices for the consumers and lower competitiveness for European industry;

- with more and more renewables subsidised out of the market, retail prices will continue to increase while wholesale prices will keep on decreasing, the mid-merit power plants will become less and less profitable which will result in mothballing or decommissioning more and more power plants, and the security of supply will be more and more threatened.

During summer 2013, the *Commissariat général à la stratégie et à la prospective* (CGSP) has been commissioned by the French Prime minister to conduct an analysis of the current situation and mid-term prospects of European wholesale electricity markets. The CGSP has in turn asked three energy economists to provide their insights on this subject:

- Marc Oliver Bettzüge, Professor of economics at the University of Cologne, and Managing Director and Chairman of the Management Board of the Institute of Energy Economics at the University of Cologne (EWI);
- Dieter Helm, Professor of Energy Policy at the University of Oxford, Fellow in Economics at New College, Oxford;
- Fabien Roques, Associate Professor at the University of Paris Dauphine, and Senior Vice President at Compass Lexecon.

This report represents the outcome of the work achieved by the CGSP and these economists: the first chapter presents the CGSP's views and the three following chapters those of the economists. Each chapter entails a diagnosis of the current crisis of European electricity markets and provides short- and long-term recommendations for a sustainable European electricity market and policy framework.

The analysis we carried out have led us to come up with the following conclusions and recommendations.

First of all, Member States along with the European Commission need to clarify the aims of the integrated energy market and of the different European energy policies. When defining energy policies, Member States should ensure that they are consistent with one another without overlapping and that setting new policies will not undermine or compromise the others policies in force. For instance, regarding the 2030 objectives, it should be more efficient to tackle separately the objectives and the means to achieve them and to consider CO_2 emissions reduction as the main, if not the only, Climate target. But it should be done taking into account the calendar of climate change international negotiations, avoiding adopting a 2030 European target too prematurely ahead of the beginning of negotiations on the Paris agreement. In fact, the main point is that Europe finds an agreement with China and the United States on an ambitious reduction target for those three economies (and on long-term finance). In that aim, and in a strategy more or less similar to that which has been used in Durban, the EC may take advantage of an alliance with African countries and, in particular with the least developed countries.

Besides, in the short term, some improvements are required in a European coordinated approach:

- first, as desired by the European Commission, the electricity target model needs to be completed by extending the day-ahead market (scheduled in the next future) and by also working on better integration of shorter-term markets such as intraday markets and on improved balancing mechanisms; a more interconnected market would also be beneficial as it would help to alleviate some of the national or local network balancing constraints, and would allow optimizing the balance between demand and supply over a wider geographic area. But, because interconnections are expensive, an optimum has to be found in deployment of new international power lines;
- then, an appropriate intervention is necessary in the EU ETS to give a real price signal, in particular for low-carbon investments. The backloading of 900 million carbon permits is seen by many as a first step in the right direction: but its consequences must be precisely analyzed, among others, on the final power prices for customers. Moreover, this action isn't likely to change the merit order: at current coal and gas prices, a carbon value of 40 to 50 euros per ton would be needed to incite switching from coal to gas. If technology neutrality is no longer required, a way to stop the expansion of coal in the short term could be through regulation, by setting emissions performance standards. In the longer term, structural reforms of the ETS are needed. Introducing a clear and stable long-term reduction goal for 2030 thus remains essential, but must be done taking into account the calendar of climate change international negotiations. Other measures might be applied: a floor price, as set by the UK, may be a good price signal for long-term investments; a ceiling price is also needed to avoid a unexpected loss of competitiveness; a carbon central bank, as mentioned by Claude Mandil, could be a good way to manage the carbon market and the carbon permits with a margin for some adjustments;
- also, the renewables, which have reached technological maturity, should be driven by market mechanisms only. If needed, a temporary additional remuneration system (e.g. system of premium) could be granted. Regardless of the remuneration system, RES producers should be subject to the same responsibilities and liabilities as those of conventional energy producers: a way to make RES producers take part to the balancing mechanism must thus be implemented quickly. In the meantime, a first step would be to stop the feed-in tariff payment when wholesale prices are negative. . For the renewable technologies for which important progress is expected, financial supports should rather be used for R&D expenditures or for demonstration projects;
- fourth, if the actual generation adequacy outlook on electricity (between supply and demand) is based on the technical lifetime of generation assets, another adequacy exercise for the European Commission should include the economic

parameters of the existing and future generation of power plants (to take into account the possibility that some back-up generation assets may be prematurely decommissioned for economic reasons).

Will those modifications be sufficient enough to create good conditions for long-term investments and to ensure long-term security of supply? There is no consensus on that point:

- for some economists, a really integrated and liberalised European electricity market could give good price signals for investments through for instance the forward electricity market (at two or three years);
- for others, the electricity market won't be able to give the right signal for security of supply or long-term (twenty or thirty years) investments. A central buyer, with a long-term vision, is then needed to secure long-term contracts. Or, governments will have to design capacity mechanisms to ensure that security of supply is met. Even if there's no academic consensus on that point, capacity mechanism may also be an answer to the missing money problem. In that case, a solution would be to define a European capacity mechanism (after a fine tuning of each country's and actor's "burden" in term of capacities). But, the Member States' needs – for instance for base load, peak or balancing capacities – are very different from one another so that it will be very difficult to design a common mechanism for all Member States. Moreover, as such a mechanism would be very complex (the resulting price will be in particular very dependent on the constraint which is set), a second solution would be that the EU set common principles for these mechanisms while Member States, free to build their own mechanism under the European rules, study the compatibilities and complementarities in their design with their neighbors.

In a more fundamental approach, the role of marginal costs pricing as the pillar of electricity markets should be revised. They give an efficient dispatching of means of production on a day-ahead basis. But, in a market with an important electricity production at low marginal costs, coming for instance from a great development of renewables, structural reforms are necessary to let economic signals emerge allowing for long-term efficient investments. They need to be, as much as possible, the result of a coordinated reflection between the Member States in order to define jointly the tradeoffs between security of supply, climate change and affordability.

Demand side must also be taken in consideration. Prices for customers are increasing quickly, generating on one side a fuel poverty that the crisis has initiated, and on the other side the occurrence of self-producers who benefit from the electricity network when they need it, but who don't pay its development and operating expenses. Common solutions must be found on the way these charges can be distributed on a social and economically efficient basis. More generally, demand side management and energy efficiency policies must be designed to fit to the other goals of the European energy policy and not to distort the market.

At last, the reinforcement of R&D cooperation between Member States is an important part of the European energy policy. The electricity landscape would be entirely transformed if for instance real electricity storage at low cost (other than hydraulic one) did exist for vehicles and for managing peak demand on the grid. To open new options for the future and restore Europe in its leadership in those domains, technological roadmaps must be precisely developed, to calibrate the Europe's and Member States' R&D effort and spending, mainly in new RES, energy storage, smart grids, energy efficiency.

Recommendations

The following recommendations are the result of an analysis made by the Commissariat général à la stratégie et à la prospective[1]. The basis for this work is the three external contributions collected in this report, written by economists Marc Oliver Bettzüge, Dieter Helm and Fabien Roques. However, these recommendations do not engage them in any way.

Recommendation n° 1

To consider CO_2 emissions reduction as the main, if not the only, target of the next Climate change package by introducing a clear and stable long-term reduction goal for 2030.

Recommendation n° 2

To reconsider support policies for renewables energies by replacing the feed-in tariffs for technologies which have reached maturity by more market-compatible mechanisms such as feed-in premiums and competitive bidding processes and by stopping the feed-in tariff payment when wholesale prices are negative or when the interconnections are congested. RES producers should also be subject to the same responsibilities and liabilities as conventional energy producers.

Recommendation n° 3

To launch structural reforms of the ETS by introducing floor and ceiling prices, to give a good price signal for long-term investments and by creating a carbon central bank to have a margin for some adjustments.

(1) See the first paper: "The European electricity market at a crossroads" by Dominique Auverlot, Étienne Beeker, Gaëlle Hossie, Aude Rigard-Cerison (CGSP) and Louise Oriol (French Ministry of Ecology, Sustainable Development and Energy).

Recommendation n° 4

To achieve the European electricity market, by extending the day-ahead market, by improving the intraday market and by building, after a cost benefit analysis, more interconnections between the Member States.

Recommendation n° 5

To reaffirm the Member States' right "to determine the general structure of their energy supply": according to that principle, they will be responsible for the design of their national capacity market as soon as it will respect some European rules, but they'll have to submit their energy policy to European Peer Reviews so that the other Member States will take knowledge of the future investments program and design capacity market of their neighbours.

Recommendation n° 6

To reinforce R&D cooperation between Member States for the technologies which have not yet reached maturity.

Recommendation n° 7

To authorise long-term contracts to enable investments in a low carbon system production.

The European electricity market at a crossroads

Dominique Auverlot, Étienne Beeker, Gaëlle Hossie,
Louise Oriol et Aude Rigard-Cerison

The current defects of European electricity markets are blatant. The wholesale prices are decreasing while the retail prices are climbing higher and higher. Coal-fired plants are now more profitable than gas-fired plants. CO_2 emissions are increasing in some countries. While investments are needed in electricity generation, about 50 billion per year until 2050, the sector is less and less profitable and uncertainty is growing…

The overlapping of the European energy policies, the economic crisis and the revolution of shale gas in the US are the mains factors responsible of those disorders, but, also responsible for the relative failure of the three objectives of the European energy policy.

To move towards a new internal electricity market, four issues are addressed: the way to foster long-term investments, the need to put renewables energies into the market, the necessary improvements of the EU ETS and the next steps towards the achievement of a truly integrated European market.

1. A short history

From vertically integrated models to liberalisation in the production and retail sectors

Until the 1990s, the organisation of the electricity sector was historically under the responsibility of national governments. Although regulation was very different from one country to another, most of the electricity sector had common features with a vertically integrated model. However, in the 1970-1980s, criticisms started arising on these integrated models considered as less efficient compared to the benefits that the liberalisation could provide. Therefore, in the 1980s some countries started reviewing their integrated models and started injecting more competition, in the production and in the retail sectors. The liberalisation process in the energy sector was then driven by the European Commission which saw in the liberalisation an opportunity to create an integrated market. By allowing competition and thus increasing the number of players in the market, the main benefit expected was that retail prices would lower for final consumers. This assumption relies in the belief that competition tends to exclude inefficient and non-competitive assets. Besides, for nationally-owned energy companies, it was also considered that private companies would be more efficient in managing these assets. Moreover, liberalisation was also supposed to provide more secure supplies with more players in the market and to enable companies from different countries to sell their production to other countries through cross-border interconnections.

The Internal Energy Market (IEM) was launched by the European Commission in the mid nineties

Since late 1990s, the European Commission gradually put in place an Internal energy market (IEM) for electricity and gas. Regarding electricity, it started with Directive 96/92/EC, later replaced by Directive 2003/54/EC, which laid down a regulatory framework and some common rules for the internal market, notably regulated third party access, unbundling and liberalisation of supply. The IEM proposals were an extension of the “Completing the Internal Market” process from the mid-1980s. Spurred on by liberalisation and restructuring in the UK, the Commission attempted to extend the principles of the broader internal market to electricity and gas after 1990, with fierce resistance to liberalisation from French and German utilities and governments.

In 2007, the European Commission published a report which presented the progress made on the internal energy market but highlighted that requirements of the directives on electricity and gas have not been appropriately implemented in certain Member States. This led to a new legislative package, called “Third Energy package” adopted in July 2009, aimed at introducing common rules for the generation and transmission (with notably unbundling of transmission networks and generation), distribution and supply of electricity. It established National Regulatory Authorities in each Member State and implemented an Agency for the Cooperation of Energy Regulators (ACER), as well as the European Network of Transmission System Operators in Electricity (ENTSO-E). Finally, this package also defined universal service obligations, consumer rights, and clarified competition requirements.

The 2012 communication from the Commission[1] reminds that the European Union needs an internal energy market that is competitive, integrated and fluid, which would

(1) Communication from the Commission to the European Parliament, the Council, the European economic and social committee and the Committee of the Regions, “Making the internal energy market work”, COM(2012) 663 final.

provide a solid backbone for electricity and gas flowing where it is needed. In order to tackle Europe's energy and climate challenges and to ensure affordable and secure energy supplies to households and businesses, the Commission wants to ensure that the internal European energy market is able to operate efficiently and flexibly. Despite major advances in recent years, more must be done to integrate markets, improve competition and respond to new challenges. As underlined by the Commission's Energy Roadmap 2050, the Commission states that achieving the full integration of Europe's energy networks and systems and opening up energy markets further are essential in making the transition to a low-carbon economy and maintaining secure supplies at the lowest possible cost.

Target model for electricity, regional initiatives and day-ahead market coupling are some key elements of the IEM

The Third Energy Package set forward a plan to implement a Target Model for electricity and gas markets in Europe by 2015 in which the main objective is to ensure the optimal use of power generation plants and transmission infrastructure across Europe through the optimal use of transmission network capacity in a coordinated way, achieving reliable prices and liquidity in the day-ahead market (with single price-coupling) and achieving efficient forward market and intraday market (with a European platform for continuous trade with implicit allocation of capacity).

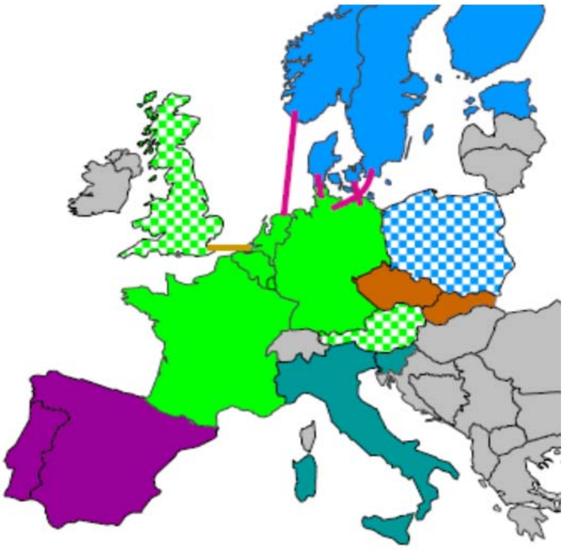
As part of this plan, ENTSO-E is thus tasked to define legally binding network codes, in accordance with the framework guidelines defined by ACER.

In parallel, a more bottom-up market integration process is at work though the creation of the Regional Initiatives (RIs) and other independent regional integration projects (such as the Trilateral Market Coupling) as drawn on the graph below. These work streams have led to a number of successes in regional market integration. In particular, the implementation of market coupling on a regional basis has allowed some efficiency gains in the use of interconnections, and led to stronger price convergence between couples markets. Indeed, market coupling optimizes the allocation of cross-border commercial flows, which improves the national markets integration. Market coupling involves both TSO and power exchange companies and aims at a better use of available cross-border capacities, therefore leading to a larger harmonisation of prices throughout the interconnected countries. Price coupling creates a unique exchange zone and a unique price when interconnections allow it (i.e. when they are not saturated).

For instance, in 2006, France, Belgium and the Netherlands have implemented a price coupling. In 2010, Germany and Luxembourg joined this initiative, which led to a strong increase in the price convergence between the different countries. These 5 countries represent the Central West Europe (CWE) market. And, in fact, the wholesale market price was the same in France and Germany during 67% of the time in 2011 and 64% in 2012. But, according to the Epex Spot exchange, during the first semester 2013, day-ahead prices were the same only on 42% of the trading days; showing the limitation of interconnection between France and Germany.

Different market coupling zones exist in Europe at the moment:

Situation of market coupling at the end of 2011



REGIONAL IMPLICIT AUCTIONS		
	CWE	Price coupling
	Austria	AT price coupled to GE/CWE (no congestion)
	BritNed	GB price coupled to NL/CWE
	Nordic + Estonia	Price coupling, also Poland via Swepol
	ITVC	Volume coupling CWE - Nordic
	Italy - Slovenia	Price coupling
	Mibel	Price coupling
	Czech - Slovak	Price coupling

Source: APX Endex

A new significant step towards an integrated market is scheduled in the near future, where there will be a price coupling of the day-ahead wholesale electricity markets in a region, the North-Western Europe (NWE), which will cover the markets of Germany/Austria, France, Belgium, Netherlands, Luxembourg, Great Britain, Denmark, Finland, Sweden, Norway, Estonia, Latvia, Lithuania, and Poland (via the SwePol Link). The NWE countries' electricity demand is about 75% of the Europe's one.

Nonetheless, the next (and final) step towards an Integrated Market will be to deliver a Single European Market not only for day-ahead but also for intraday, forwards and balancing markets.

The European Integrated electricity market made significant technical progress

Since 1996, significant progress has been made towards the single European market. While there used to be no competition at all, now, competition exists for production as well as for retail (except in certain countries) and markets have become more liquids even if some markets, such as Eastern European markets, can still improve their liquidity.

Moreover, transparency has increased as well, with data being published almost in real-time. The third package has thus driven market integration with a pan-European regulatory framework. Market coupling initiatives have been rolled out and some coupled areas are soon to be merged, contributing to the single European market. In the years to come, the NWE zone will be merged (part of the PCR initiative) with Italy-Slovenia, Spain-Portugal and Czech Republic-Slovakia markets. Further improvements can also be expected from the implementation of the Network codes, in line with the Target Model, even if some of these network codes are likely to be delayed because of major obstacles that can be explained by the variety of historical approaches adopted by each TSO.

2. A market in crisis

20 years after the start of liberalisation, the evidence is mixed regarding the achievements of liberalised electricity power markets. In some part, the Internal Energy Market is a success. But, despite many achievements to date, the building up of the European electricity market is facing several dysfunctions.

An oversupply situation and large volumes of renewable energy sources leading wholesale prices to fall down

While electricity demand had been growing on average by about 50 TWh per year in the EU-27 between 2000 and 2007 (or about 1.7% per year), electricity demand remained in 2012 about 4% (112 TWh) below the peak reached in 2008. During the same period, renewables production increased by 176 TWh, such that demand for conventional production has dropped by 288 TWh.

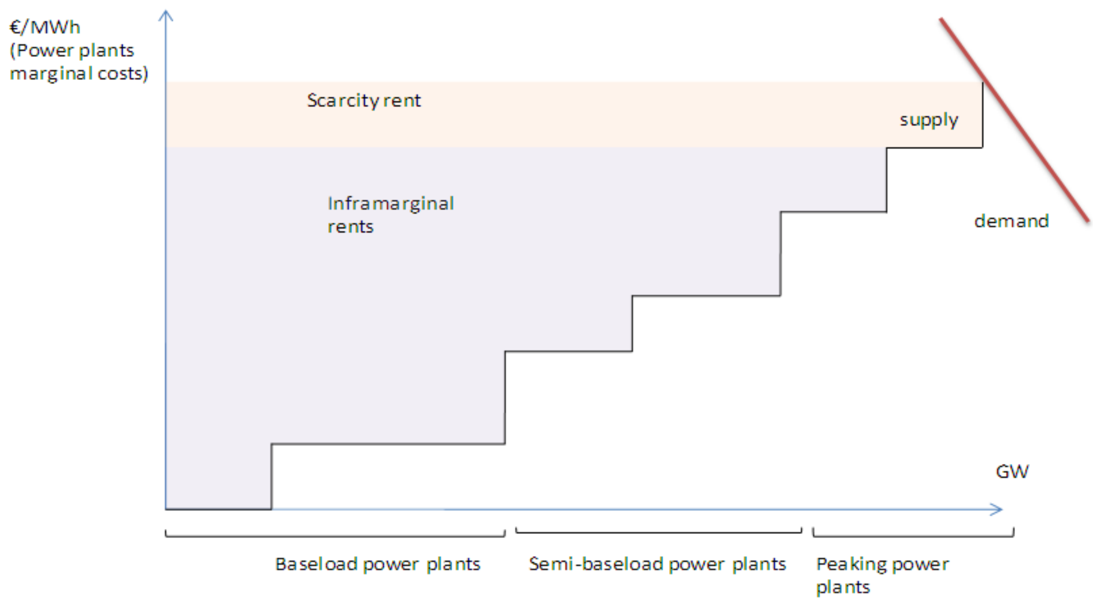
In parallel, the large volume of renewable energy sources (RES), whose marginal costs (see box 1 below) are almost zero for PV and solar, are subsidised “out of the market” and are often granted priority of access and dispatching. As a consequence, the costs of balancing the system fall on to conventional generators. Whenever the RES technologies generate, they displace other technologies (which produce at higher marginal costs) resulting in lowering wholesale prices (see box 2 below). Because they are subsidised out of the market, they have an incentive to produce even when the system is oversupplied. This leads in some cases to significant distortions in power price dynamics, such as negative power prices.

Box 1: Marginal cost pricing model

In theory, in a situation of perfect competition, the price is set at the marginal cost of the last power plant "called" to meet the demand. Indeed, each power plant can be ranked according to its short-run marginal costs of production (O&M costs), so that the plants with the lowest marginal costs are the first to be brought to meet demand and the plants with the highest marginal costs are the last: the ascending order of the marginal costs of production of power plants is called the **merit order**.

The merit order illustrates the fact that the electricity produced by the plants with the lowest net cost is dispatched first which enables minimizing the overall electricity system costs to consumers. For the plants with the lowest marginal costs, the price is often fixed at a level far above their marginal costs: this induces for these plants a rent called **infra-marginal rent**. Thus, in this model, the production mix tends to an optimum where infra-marginal rents enable the power plants to cover their capital expenditures.

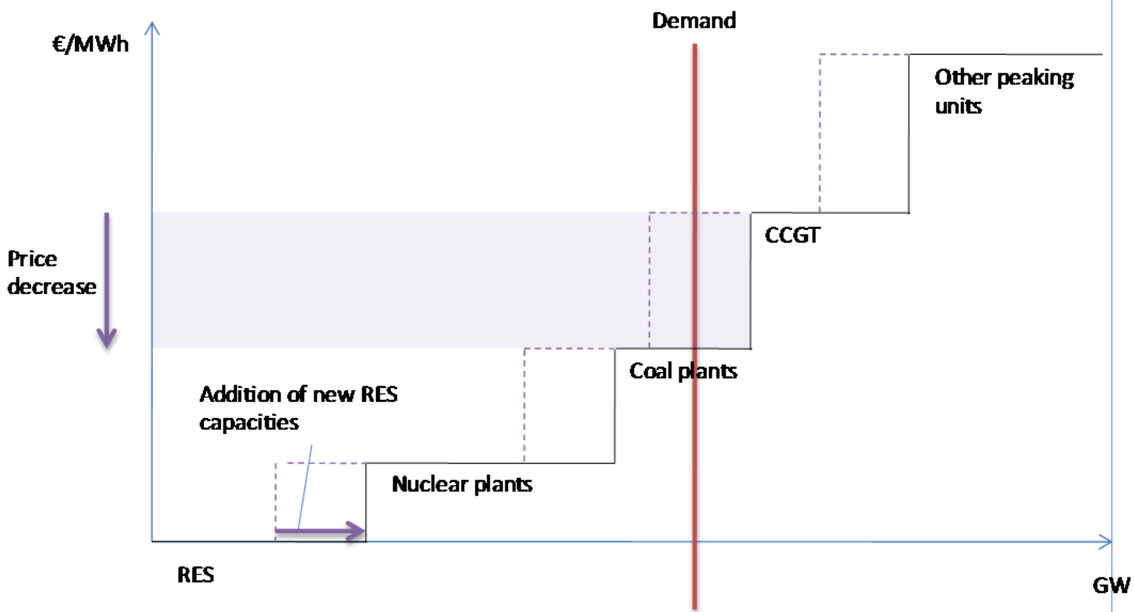
For peaking units, their capital expenditures (which are however lower than those of baseload power plants) are supposed to be covered via **scarcity rents** which occur in times of very high demand (resulting in very high peak prices). This is grounded theoretically in the "Peak Load Pricing Theory", whereby marginal pricing can provide the recovery of the capital costs based on the scarcity rents that all power producers earn when the system is tight. The assumption underlying is that power prices could climb to the "Value of Lost Load (VOLL)" at times of scarcity and that this would naturally lead market players to benefit from periods of high prices to remunerate their fixed costs.



Box 2: Missing money and merit order effect

The "missing money" problem, which is still not an academic consensus, refers to the fact that for a variety of reasons – ranging from operational price caps to the political unacceptability of very high power prices –, power prices are not allowed in practice to reach the "value of lost load", leading to a chronic shortage of revenue for plant operators. For instance, price caps have been set in the French and German power exchange at +/-3000 €/MWh, which means that the price cannot exceed these limits. So far, the ceiling of +3000 €/MWh has never been reached except at one occasion but it was due to a malfunctioning of the power exchange.

Moreover, an addition of new RES capacities displaces the merit order as illustrated in the graph below:



This results in lowering the prices, thus diminishing the infra-marginal rents and diminishing the load factors of CCGTs (combined cycle gas power plants) and other peaking units which do not get the sufficient rents to cover their investment costs. This amplifies the missing money problem.

Moreover, this fast development of RES production has not been followed by the grid development that is necessary for the system. Thus, RES cause network externalities such as reductions in cross border capacities, controversial loop flows which are highlighted by the decrease in price convergence in the CWE market. While price convergence was about 66% in 2011 for CWE countries, it fell to 46% in 2012.

A declining profitability of thermal power plants, especially gas power plants, and a tough situation for the main traditional utilities, which raises security of supply concerns

Subsidised renewables production displace generation from thermal sources, which combined with the decline of power demand following the economic crisis has dramatically reduced load factors for gas power plants.

In addition, wholesale power prices have fallen to levels which are now disconnected from the generation costs of conventional means – and are reflecting the downward pressure on prices associated with the development of renewables. As a result, the ten largest utilities have already announced about 38 GW of closures, but IHS CERA estimated that a further 113 GW (out of 330 GW of thermal plants in operation in EU 27[1]) are at risk of closure in the next 3 years in the absence of regulatory action. These large retirements of capacities could rapidly counterbalance the oversupply situation and lead to negative capacity margins.

On top of that, the main traditional investors in the electricity sector – European utilities – are in a weak financial situation as they enter into a massive investment cycle. The total net debt position of the 10 largest European utilities nearly doubled over the past 5 years to reach about 280 billion Euros. This implies that European utilities will only be able to contribute to equity financing of a fairly small portion of the 40 to 60 billion Euros needed each year in power generation in the next decades.

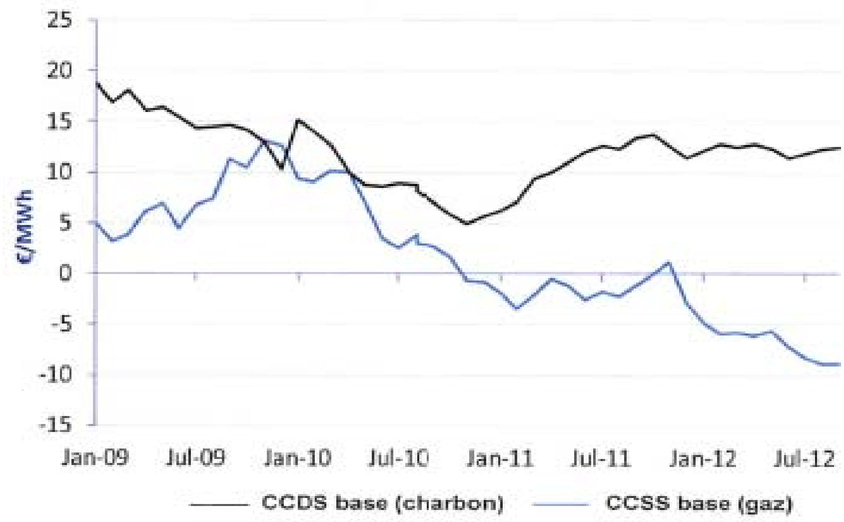
A modification in the merit order between coal and gas power plants in favor of coal, resulting in more CO_2 emissions in Germany, UK and other European countries

The carbon price of the EU ETS was supposed to give an incentive to secure long-term investments in low carbon technologies. But ETS carbon prices have been trading below 10 €/tCO_2 for the past couple of years. Combined with the low level of coal prices, this has resulted in increasing the profitability of coal power plants at the expense of CCGTs (combined cycle gas power plants). Indeed, in the last couple of years, Clean Spark Spreads (CSS)[2] fell below Clean Dark Spreads (CDS) and are even negative while CDS are still positive.

(1) See IHS CERA Multi client study: Keeping Europe's Lights on: Design and Impact of Capacity mechanisms, August 2013.

(2) Clean spark spread for gas plants and clean dark spreads for coal plants represent the spread between electricity prices and the production cost of the plant (which depends on fuel and CO_2 price). It gives the theoretical gross margin of the plant.

Coal versus Natural Gas price
(Carbon Compensated Spreads)



Evolution of CDS and CSS between 2009 and 2012 – Source: GDF Suez

It led to a switch from gas to coal in the merit order with coal power plants being more competitive than brand new CCGTs. A level of about 40 to 50 €/tCO_2 is needed to reverse the situation, at the current price conditions of these fuels. Thus, some CCGTs have been mothballed all across Europe, new gas investments curtailed and, as a result, emissions have risen in some European countries: between 2011 and 2012, the GHG emissions increased about 1,5%[1] in Germany when electricity consumption decreased by 4,6%.

A significant growth in retail prices (especially for residential consumers) which is increasing fuel poverty and self-consumption

While wholesale power prices have been dramatically decreasing – French day ahead power prices were on average about 70 €/MWh in 2008 and are now about 42 €/MWh in 2013 –, retail prices for residential and tertiary consumers have increased by 7% per year in EU. For industrial consumers, final electricity prices have risen 21% between 2008 and 2012. This increase in retail prices is mainly due to the costs of renewable support schemes that are externalised from the electricity market and are added through levies and taxes to the consumer bill. In Germany, renewable energy contribution through the EEG (Erneuerbare Energien Gesetz) has risen for the residential consumers from 2 €/MWh in 2000 to 36 €/MWh in 2012 and 62 €/MWh for 2014[2]. Indeed, according to Germany's four network operators, the annual cost to support German renewable energy feed-in tariffs is set to rise to €23.6 billion in 2014,

(1) Globally, not just in the electricity production sector.
(2) Electro-intensive industries benefit from exemptions which lower their EEG contribution in €/MWh.

from €20.4 billion in 2013. Supports costs for renewables in Europe have risen to more than €30 billion in 2012 (without taking into account some costs such as grid reinforcement, balancing and back up). As a matter of fact, some European countries including Germany, Spain and Italy have recently reduced their generous support schemes for renewables which led to spectacular – and sometimes uncontrolled – deployment of renewables, particularly solar PV.

In Germany, retail prices are among the highest in Europe for residential consumers whereas the wholesale price represents roughly 15% of the total end-customer price. Prices for industry are twice as high as the prices in the USA. Added to that is the fact that the grid development that will be needed for the network to cope with massive RES volumes will induce additional costs for the consumers.

In the UK, there was a harsh debate between the Prime Minister and Edward Miliband in the House of Commons on October 30th to understand why although wholesale prices have hardly moved for a year, retail prices rose by about 10%: the Energy secretary of state announced a new review of competition in the market.

The rise in electricity prices and the economic crisis have led to a significant increase of energy poverty in the past few years in Europe: 50 to 125 million people suffer from fuel poverty[1].

On the other hand, as retail prices increase, self-consumption becomes more and more profitable for the residential consumers who can afford the installation of PV panels on their roof. Self-consumption consists in consuming power which is self-generated, without resorting to any third party. In practice, theses consumers are not self-sufficient all year long. In short, there are times where they consume more than they can produce, times where they do not produce (during the night) and times where they consume less than they produce (their production surplus is thus injected into the grid).

Self-consumption is largely developed in the industry, generally with co-generated heat, but it has been gradually developing among residential customers. Today in Germany, 2 or 3 TWh of decentralised PV are assessed to be self-consumed, but this volume is growing rapidly. Indeed, as the price of power for residential consumers in Germany will exceed 300 €/MWh in 2014, while the FiT for PV is less than 150 €/MWh, it clearly becomes more interesting to self-consume than to be paid the FiTs. However, the problem with self-consumption is that in the current state of regulation, self-consumers do not pay at the right level the services that the system provides to them (the part that is proportional to the consumption which includes the taxes, the variable energy and grid access part of the tariffs). These costs are thus divided up among the other consumers, increasing their bills.

(1) Source: EPEE, Tackling fuel poverty in Europe, Recommendations guide for policy makers 2009.

3. The current situation

The stakes of the European energy policy can be summarised by a trilemma of three objectives: security of supply, climate change and affordability. The main challenge would be to achieve these three objectives simultaneously.

But, for the moment, three main factors prevent from really reaching them:

- the overlapping of the European energy policies, in particular of the Internal energy market with the Climate change package, which induced a large amount of RES that are subsidised "out of the market": those tradeoffs create major distortions on the electricity market;
- the economic crisis, which, associated with the CCP, created an oversupply situation;
- the revolution of shale gas in the US which puts back coal in the center of European stage.

As a consequence, the economic signals of the Internal energy market and of the EU ETS are very poor and not sufficient enough to support the new investments needed to decarbonise the sector and renew ageing infrastructures.

The overlapping of the European policies created distortions on European electricity market: the objectives must be clarified

If the Internal Energy Market (IEM) was launched in the mid-nineties and the EU ETS by 2005, the Climate change package was set by EU leaders in March 2007 and adopted at the end of 2008. But, the overlapping between IEM and CCP were not taken into account and the tradeoffs were not examined.

It seems that, in adopting the Climate change package, policymakers have focused on the ecological angle of the policy trilemma, leaving the two other angles (security of supply, affordability) and the IEM largely out of the discussion. Indeed, the Climate change package is a set of binding legislation which aims to ensure the European Union meets its ambitious climate and energy targets for 2020. These targets, known as the "20-20-20" targets, set three key objectives for 2020:

- a 20% reduction in EU greenhouse gas emissions from 1990 levels;
- raising the share of EU energy consumption produced from renewable resources to 20%;
- a 20% improvement in the EU's energy efficiency.

Those targets were adopted at the end of 2008, in a context of economic prosperity and growth (+2.8% per year on average between 2004 and 2007, for EU-28) and of rising fossil fuel prices (from 9$ per barrel in 1998 to 145$ per barrel by the end of July 2008). The assumption of EU leaders was that these trends would go on, that the renewables would be competitive without any more subsidies in the following years and that the European Union would take the leadership in the conception and production of renewable energy sources. But, in fact, after the CCP was launched, these expectations proved to be inaccurate: the economic crisis has reduced the demand; following the shale gas revolution, the coal price has decreased; and the fossil fuel prices are well below their prices of July 2008.

Regarding the Climate change package, two kinds of overlapping can be highlighted:

- within the CCP: the three targets (energy efficiency, RES development, CO_2 emissions reduction) are not independent: energy efficiency policies and RES support policies have an impact on CO_2 emissions and thus on EU ETS, RES development impacts demand response as it lowers the wholesale market prices, making demand-response less profitable… One of the three targets (CO_2 emissions) is supported by a Europe-wide mechanism (the EU ETS), whereas for the two others, the European Union left it to the Member States to implement national support policies.
- between the IEM and the CCP: policy interventions in the framework of CCP are not without consequences on the structure and the design of electricity markets. The relationship between IEM and CCP was probably underestimated, and CCP policy interventions have weakened the IEM.

Moreover, no competitiveness goal has been taken into account.

Those overlapping targets have created distortions on European electricity markets. Thus, before adopting new objectives in energy policies, which would probably interfere with existing energy policies, the overlappings must be carefully studied, in order to minimise them. In conclusion, regarding the 2030 objectives, it should be more efficient to clearly distinguish between the objectives and the means put in place to achieve them and to consider CO_2 emissions reduction as the main, if not the only, European energy target. Secondary targets could be added only after being studied as complementary to the main one.

The climate change package induced a large amount of RES that are subsidised "out of the market" creating major distortions

The Climate change package set a RES target at the European level which has been divided up nationally according to the countries' renewable energy potential, their energy mix and their GDP. The mechanisms to promote RES development are entrusted to the MS and they have defined national support policies to reach their targets. Most of these support policies:

- are price-oriented (rather than quantity-oriented, see table below): feed-in tariffs (FiTs) have been the preferred approach but are not responsive to the wholesale market prices. In some countries, they are gradually being replaced by feed-in premiums (ex-post premiums such as contract-for-difference in the UK or ex-ante premium like in Spain), which can be seen as an improvement compared to FiTs in terms of responsibility for the RES producers;

- discriminate between technologies (the supports – FiT, premium, CfD… – vary according to the type of technologies); generally, PV panels are more subsidised than off-shore-wind, that is more subsidised than on-shore wind;
- grant RES priority access and dispatching in the electricity networks;
- subsidise deployment of existing technologies rather than research on less mature technologies.

Two approaches for public policy to correct market failures: prices vs. quantities

Prices	Quantities
The public authority sets the financial level of intervention. The producers receive a financial incentive to produce public good.	The public authority sets the level of public good that should be reached, and then divide it in individual objectives (quotas).
Examples: To reduce carbon emissions: carbon tax To develop RES capacity: feed-in tariffs, feed-in premium, contract-for-difference	Examples: To reduce carbon emissions: quotas (EU ETS) To develop RES capacity: call for tenders, green certificate scheme

RES are quasi zero marginal cost technologies, and by displacing the merit order, they caused a huge decrease in wholesale prices.

The introduction of a significant amount of intermittent RES capacities on the grid, at a sustained pace, has raised the intermittency issue, weakened security of supply, and threatened the business model of some power plants (gas power plant stations' load factor is reduced, lower peak prices affect the pumped-storage hydroelectricity business model). It has to be underlined that the RES development has been faster than the grid developments, causing bottlenecks when volumes of RES are high, the main issue being that network infrastructures development has a much longer timeframe than RES development time frame. Indeed, network infrastructures are subject to longer administrative procedures and are often hampered by the lack of acceptation of such projects by the local population.

The economic crisis reduced electricity demand sharply, created an oversupply situation and made meaningless the price signal of the wholesale market and of the EU ETS

The economic crisis reduced power demand sharply, creating a deficit of demand of 10%. Meanwhile, renewables and thermal production increased, creating an overcapacity situation and decreasing wholesale prices, which have become more volatile.

In 2007, carbon price was 17 € per ton on average on the EU ETS market. But, consequently to the economic crisis and that lower demand, carbon emissions decreased, making CO_2 target easier to reach, and thus lowering CO_2 price on carbon market so that the carbon price does no longer stimulate new investments in low-carbon technologies.

In that situation, electricity and CO_2 market aren't any more good drivers for long-term investments.

In theory, the electricity market should give a price signal, which is the marginal cost of the last power plan "called" to meet the demand. But, today, the wholesale price is often below the marginal cost of the amortised power plants, so that some gas-fired plants are mothballed, when we needed them for security of supply. Moreover, the coverage of the capital expenditures is no more ensured by the market outlook.

At last, the wholesale price differential between peak hours and off peak hours is becoming smaller and smaller so that the uncertainty about the coverage of investments even in hydraulic storage is important.

The revolution of shale gas put coal back in the center of the European stage

In parallel to the economic crisis, the development of shale gas production in the United States has taken place in the context of high fossil fuel prices before 2008. US natural gas prices have been halved in the past five years, leading to a major shift from coal to gas in the US that put abundant quantities of coal, at a low price, on the European market: in Europe, the coal price decrease was about 20% from the beginning of 2012 until its end. As a result, electricity production from coal increased in most European countries while electricity production from gas decreased between 2011 and 2012.

None of the three objectives of the European energy policy has really been reached

The result is that, under the impact of the economic crisis, of the climate change package and of shale gas, which induced an unexpected and countercyclical RES development, none of the three objectives of the trilemma has been reached and that security of supply and affordability has come back to the forefront of the European energy policy agenda:

- affordability: whereas electricity wholesale prices are abnormally low due to distortions, final electricity prices for residential and tertiary consumers, and, for industrial consumers (but to a lesser extent because they benefit from tax exemptions) are increasing with two consequences: industrial sectors are losing competitiveness, the real risk being the localisation of new industries in other countries (in USA in particular) rather than relocation of existing industries, and residential customers are facing more and more fuel poverty;

- security of supply: security of supply is threatened as many CCGTs would be closed or mothballed in the absence of regulatory intervention, intermittency of RES is not yet well managed, networks are facing congestions and, last but not least, security of supply remains a national prerogative that the EM are not likely to hand over to the European Commission;
- climate change: even if the objective of reducing GHG European emissions by 20% (between 1990 and 2020 is nearly reached (19,9% at the end of 2012), the shift from gas to coal in many countries hampers the decarbonisation objective.

Waiting for the future is not a solution: without any action, the crisis is likely to deepen

In the next decade, electricity demand growth will remain low, due to low economic growth perspective (less than 1% per year) and possible decrease of electricity demand elasticity to GDP in case of efficient energy efficiency policies.

In parallel, the RES development, out of the market in most countries, is scheduled to reach the objective of 20% in the share of EU energy consumption.

Without any action, the consequences are likely to be more and more important in the near future:

- a more important oversupply situation and a new development of renewable energy sources (RES) leading to a new decrease of wholesale prices;
- a bad profitability of thermal production which could lead to closure of many power plants and supply problems;
- a new significant increase in retail prices (especially for residential consumers) and the development of self-consumption (especially in Germany) which will require a new approach into the current rules regarding the grid access tariffs.

Moreover, whereas wholesale prices do not reflect the real cost of energy production, RES support costs are increasing and are supported by the final consumers, thus with a complete disconnection between wholesale prices and prices paid by final consumers, which raises now the question of self-consumption. Self-consumption is still not an issue in France considering the comparatively low electricity tariffs but is becoming a major one in Germany. As explained in 1.4, self-producers do not pay at the right level the services that the system provides to them such as the access to the grid. They neither pay the taxes for renewables, transferring these charges to the other consumers, whose number is decreasing when the number of self-consumers increases. While the price per kWh paid by these "captive" consumers is growing, in the same time, costs of PV technology are supposed to lower, still raising the number of self-consumers.

In most cases, self-generators' production is variable and intermittent, as in the case of solar PVs, which means that they rely on the "grid" to balance their local consumption against variable generation. Yet, if the prevailing tariffs are based mostly on net volumetric consumption (they still pay the fixed part of the tariffs), they end up paying virtually almost nothing for grid's vital services. This phenomenon has severe drawbacks for the power systems, with a missing money problem, and for the collectivity with potentially high social consequences.

Lastly, as we will see in the next section, the overall impact has been to make investments in electricity production no more profitable – except for technologies supported by direct government-based feed in tariffs and contracts for differences. As a result, the need for direct government investments and guarantees will be more and more important.

4. Some hints towards a new internal electricity market

It appears that four issues need to be addressed in a coordinated way, in order to improve the current situation:

- attracting investments in the sector;
- limiting the distortions caused by RES support schemes by integrating them into the market;
- restructuring the EU ETS;
- completing the internal market.

The industry cost structure is changing and the current situation fails to attract investment, leading several countries to consider capacity mechanisms and long-term contracts

Significant investments will have to be made in both the short- and long-term to decarbonise the sector and renew ageing infrastructure. But the current situation is likely to result in a lack of investments due to the low profitability and fallen attractiveness of the electricity sector. **This lack of investments is thus threatening both the objectives of decarbonisation and of security of supply.**

Moreover, low-carbon technologies (RES technologies, nuclear plants…) are changing the cost structure of the market because they have high capital expenditures (CAPEX) and very low operational expenditures (OPEX) whereas carbon intensive technologies are characterised by lower CAPEX and generally higher OPEX. In a future where renewables would represent a dominant share of the generation mix, this change in cost structure would probably raise the question of the validity of the marginal cost pricing market theory which inspired the liberalisation process. Indeed, if this theory works well with technologies with significant O&M costs, it is not sufficient anymore in itself to spur investments in low-carbon technologies because of the risks embedded, in particular that the energy-only market will not provide sufficient revenue to cover capital expenditures. Exploratory works to study alternative models in the long term (after 2025) should be engaged.

Box 3: The Brazilian experience for investment in new capacities

In order to ensure security of supply, Brazil has implemented a mechanism that require the distributors (that are also in charge of supplying energy to the end-consumers) to cover the energy needs of their consumers through contracts that are based on tenders organised by the government. This system is based on the energy needs rather than the capacity needs because of the large share of hydro-power in the electricity production (about 80% of the electricity production): the uncertainty is therefore on the production because climate conditions can greatly influence the level of production. Therefore, this particular situation represents a major difference with the European situation.

The Brazilian electricity market is organised around a free market where only large consumers can participate and which represents one quarter of the electricity exchanges, and a regulated market, representing the rest of the exchanges. In the free market, the consumers have to enter into a contract with a producer that will cover all their energy needs. In the regulated market, public tenders are organised by a broker according to the distributor needs, where only producers holding an environmental license can participate. The winner of the tender is the producer that offers the lowest price. He is then compelled to conclude contracts through the broker with the distributors according to their demand levels. The government distinguishes tenders for existing capacities (where investments are already paid off) and new ones. For new capacities, it even has the possibility to choose which kind of technology is wanted (wind power, thermal power, etc.) although they are generally technology neutral. For existing capacities, tenders are organised one year prior energy delivery and contracts cover a period from 5 to 15 years. For new capacities, tenders are organised 3 to 5 years prior delivery and contracts are concluded for 15 to 30 years. In this case, the price covers the levelised energy cost of the unit.

Between 2005 and 2010, 23 tenders were organised for new capacities leading to 61 GW and about 500 new units. 97% of these new capacities come from RES.

Beside the current situation in the electricity sector which does not attract investors, the lack of continuity in the energy policies during the lifetime of the installations is a factor explaining this lack of investment. Indeed, private investors don't commit themselves in the long term and don't take the risk to invest without State guarantees because government are likely to change the rules and adopt policies that would affect their investment decisions. Thus, private investors do not want to take the risk to have stranded assets. **Continuity of the rules for all the energy actors is a challenge but must be a priority for the Member States and the EU.**

It has been observed in the recent years that governments have taken the role of risk handlers in order to spur investments in renewable support schemes, with a large majority adopting schemes revolving around a central buyer. In this view, risks are transferred onto consumers – who have no possibility to escape the system except with self-consumption – and governments.

This could be seen as an opposition with the IEM directive which explicitly encourages short-term switching and hence undermines long-term contracts. A possible solution could be to make the IEM facilitate long-term contracts even if it limits customer switching. In fact, long-term contracts do not necessarily go against competition as they can be signed directly with suppliers and can be awarded in a competitive way through tenders. Thus, long-term contracts could be technology neutral and could be tendered to maintain competition and could only concentrate on the investments, which are the most important cost for capital intensive technologies. They would come as complementary to the competition in spot and intra-day markets.

Concerning the risk of security of supply, it is still largely seen as a national concern, which explains why governments are taking action. Whether this intervention is legitimate or whether markets are more likely to provide the optimal quantity is a long existing debate between economists that has not yet reached a consensus. But beyond that, it is undisputable that governments are expected to act whenever they foresee a risk. Indeed, this current lack of investments situation is now leading the governments to take extra-measures and implementing capacity mechanisms.

Different designs can be considered in order to remunerate capacity, the question now being about which mechanism could be less distortive. In a nutshell, these capacity mechanisms should be technology-neutral, transparent and need to take into account the possibilities to import from neighboring countries and be accessible in a non-discriminatory fashion (especially cross-border).

They should create a level playing field between technologies (i.e. not exclude some generation technologies or demand side response) and should not discriminate between existing and new units.

In the long term, ideally, the European Commission should come up with a common framework (with common principles) and the capacity mechanisms implemented by the Member States should have some complementarities. The process could be similar to the development of the spot markets, with regional initiatives that have some complementarities and that could progressively be merged if each country can see a benefit in doing so. There are some difficulties to such an objective because the needs of the European countries are very different: France has a peak problem in winters, Germany has a bottleneck grid and needs capacity in some Länder and England has to replace a great part of its baseload electricity production capacities in the short term.

However, for the European Commission, the concern is that mechanisms country by country could undermine further integration of European power markets and building of new interconnections: a coordinated approach is necessary.

The several distortions observed because of renewable energies support policies are raising the case for more market-based schemes

RES support policies shouldn't discriminate between mature technologies and costs should be more explicit for the final consumers. The result is often a non-optimal deployment of some technologies, out of touch with the needs, the localisation and the available resources (i.e. wind, sun or biomass), leading to overcapacities. A level-playing field between RES technologies is urgently needed.

RES are most often granted priority dispatch, even when the wholesale prices are negative (and so are below marginal cost of RES, which is zero). Fully curtailment of RES in those situations would be economically reasonable. A short-term measure could consist in rethinking the rules of RES injection on the grid. It is broadly agreed that, for mature technologies, **RES should be integrated in the market**, with more sophisticated mechanisms.

If needed, a temporary additional remuneration system (e.g. system of premium) can be implemented; since the implementation of new rules can take some time, a first temporary step would be to stop the feed-in tariff payment (or of the premium) for all new contracts when the market prices are negative. This has been implemented in Denmark for one offshore wind farm. In this case, the marginal cost of RES which is almost null is greater than the price, and thus they must not be remunerated during these periods. According to a Claude Mandil's idea, during these periods, the RES producer will have "free" energy in excess which can be stored for further use and is encouraged to invest in storage capacities. In any case, other analyses show that at least, curtailing the RES production while still paying them when prices are negative would be more efficient than the current situation: it would allow more conventional plants under constraints to produce and should thus allow to limit the negative price and to increase the overall social benefits.

At the same time, to avoid overcapacities, a mechanism to control the installed RES capacities each year must be put in place, such as tenders.

For less mature technologies, R&D supports would be better than high feed-in tariffs. So far, under feed-in tariffs, RES producers have an incentive to produce whenever they want as their remuneration is guaranteed at a fixed price and their production is compulsorily dispatched in priority meaning that they are not balance responsible. Some countries are considering or have implemented more market-based models where the producers have to sell their production in the market and then receive an additional premium, still depending on the technology. Two kinds of premiums are generally considered and are usually given per MWh (but giving them per MW could be considered as well):

- ex-ante premium: the premium is fixed and independent from the wholesale price, which confers a higher risk level to the project that investors (i.e. the banks) are likely to reflect on their financing conditions, thus increasing the total cost of the project. If the premium is too high, there is a risk of windfall profit for the producers, if they are too low, there would be no project at all;

- ex-post premiums (like CfDs) are similar to FiTs in the sense that they still give a guaranteed price. The premium level depends on the wholesale price level. It is however an improvement compared to FiTs because they make the RES producer aware of its responsibilities, for instance in terms of balancing.

For some economists, since RES have led to many reinforcements of the network, their participation to the corresponding costs should be implemented.

Self-balancing has to be considered too with, if possible, more liquid intraday markets. In this way, RES production will be better managed and it will incentivise producers to enhance their forecast and adjust their production to the energy withdrawal in their balancing perimeter because imbalance can be very costly for them. Enhancing the RES production forecast is also essential to limit the costs for the system because bad forecasts force the TSO to increase its margins in order to be sure to be able to balance demand and supply. Some countries such as Spain have implemented mechanisms that reward the accuracy of the forecast for RES production.

More generally, RES producers should progressively be given the same responsibilities as those of conventional energy producers. The difficulties that may arise for small producers should not be forgotten, but new activities could arise such as the development of aggregators that would be balance-responsible and sell the production into the market for those who do not have the means to do so[1]. As a transitory measure, in order to incentivise the producers to switch from FiTs to premium systems, in Germany, RES producers can receive an extra premium called “management premium” that is supposed to help them to cover the costs associated with selling their production in the market, for instance balancing costs. The subsidy gradually decreases over time. Such a system could be considered in France in order to allow a smooth transition from the current system to a market-based system.

Beyond national support schemes for existing technologies, there is a need for a European coordinated R&D approach for renewables in the larger frame of an industrial policy for energy. This approach must be encouraged with much more financial support, while incentives for deploying the existing technologies should be reduced. Some European initiatives already exist: the Strategic Energy Technology Plan (SET-Plan) for low carbon technologies and the Horizon 2020 program for research in general. But these programs could be optimised in order to avoid some overlaps between Member States, to benefit from economies of scale and to create more synergies.

(1) More generally, if RES producers are not willing to become balance responsible themselves, they could contract with another balance responsible entity which would anyway force them to enhance their forecast.

In a nutshell, RES support schemes should urgently evolve. Two main steps should be considered: **first to progressively integrate RES into the market** (remuneration mainly based on wholesale prices, same responsibilities as conventional producers in terms of balancing), then **to abolish technology discriminatory approaches for mature technologies. In parallel, the costs for RES development should clearly be revealed to the consumers, and finally financial support should focus on R&D.**

The EU ETS has been weakened and calls for a restructuring on line with a 2030 CO_2 target

A central part of this issue concerning CO_2 and the EU ETS is the overlap of the EU ETS with national policies in support of low carbon technologies and energy efficiency, in the power sector. Indeed, these national policies have a significant effect on the demand for ETS allowances, as they make CO_2 emissions decrease, and thus infringe upon EU ETS function. Consequently, the EU ETS has become a "residual market" for carbon abatement in the power sector. Policies in support of renewables have been the prime drivers of power sector investments over the past decade in Europe.

A reform of the EU ETS to improve its consistency with complementary policies supporting renewables and energy efficiency is needed.

The current price signal on the EU ETS is meaningless. Indeed, it dropped from around 14 €/t CO_2 in 2010 to less than 5 €/t CO_2 in 2013, well below the "switch" carbon price to move from coal to gas (about 40 to 50 €/t CO_2 with current price conditions for gas and coal).

In short, **a structural reform is necessary to introduce clear long-term goals and a stable policy across years.**

Short-term interventions such as the backloading proposal is seen by many as a first step to improve the price signal, even if it could have a counter effect in creating a credibility loss, but its consequences must be precisely analyzed. Moreover, this action isn't likely to change the merit order: it is unlikely to sufficiently change the level of carbon prices to really lower the CO_2 emissions, to change the merit order between gas and coal and to restore the credibility of the EU ETS. Indeed, a carbon price of between Euro 40-60 would be needed to close the coal to gas gap. If technology neutrality is no more required, the only way to stop the expansion of coal in the short term is through regulation – emissions performance standard.

In longer term, structural reforms of the EU ETS are needed. There is, in particular, a disconnection between the EU ETS and decarbonisation time horizons which calls for a more radical reform.

A clear way forward for phase 4 of EU ETS and beyond is needed to give visibility to the actors for the post-2020 period. A clear and credible political constraint for post-2020 is needed but there is currently no consensus on the best time to take a post-2020 commitment. Indeed, on the one hand, it should be taken into consideration that now might not be the best time to set a 2030 objective given that there will be international climate change negotiations for the 2015 summit and that taking a position beforehand could lower the influence of the EU against China and the US: the Copenhagen strategy was not very efficient. The EC should thus wait for the start of the negotiations with those two countries which are the two main emitters and whose commitments are fundamental for a new agreement. On the other hand, it is argued by the EC, most Member States, and many businesses (including utilities) and NGOs, etc. that the EU should consistently pursue its leadership strategy by agreeing to put a reduction offer on the table before 2015 so that third countries are pressured to make a similar offer. They argue that we are currently seeing a change in the approach from countries such as the US, Brazil, China, on the issue of climate policy (in the United States, the issue of climate change is now a priority for President Obama; in China, the air quality concerns has given back importance to the issue of climate change), thanks to the ongoing efforts of the EU.

Other ideas must be studied, a floor price, as set by the UK, may be a good price signal for long-term investments, a central bank for carbon permits, as mentioned by Claude Mandil, could be a good way to manage regular adjustments of supply of carbon permits.

Market integration has made several advances but still need to be completed while some improvements can be made

Since 1996, significant progress has been made towards the single European market. But there are still areas where improvements are needed in regard to the current design of electricity markets. So far, the focus of the European Target model for electricity has historically been on the integration of day-ahead power markets. Yet price signals from day ahead markets alone are insufficient to provide the right operational and investment incentives to market participants and evidence is growing that price signals are missing both on a very short time frame – within day or within the last hour before actual production – and on a very long time frame to trigger investments when the system is tight. It is therefore recommended to complete the sequence of electricity markets with the missing elements in both the short term and in the long term. On top of that, some improvements can be made regarding interconnections, common grid models and adequacy assessments.

The need for price signals on a very short term frame

The rapid growth of intermittent renewables calls for enhancing the short term balancing with the implementation of liquid and integrated intraday, balancing and reserve markets which will correctly reward flexibility both for flexible power plants and demand side response. Approaches for intraday trading vary greatly by country, with organisation difference issues as well as liquidity issues. Moreover, balancing products will have a growing value and so far, they are rarely procured by system operators on a competitive and transparent basis. Harmonizing approaches between the different countries in these matters will provide a huge benefit for the integrated market but the differences between national electricity market designs make the coordination and definition of common rules difficult.

The need for price signals on the long-term frame

In addition, the implementation of capacity mechanisms in a coordinated way seems necessary to guarantee resource adequacy and security of supply in the long term. The design of electricity markets will also need to evolve to provide better locational signals so that production or demand response are located in nodes of the network where they are most needed.

The need for more interconnections (at a reasonable cost) between Member States and in general for a more coordinated approach to the European grid between European countries

Increasing share of RES without developing the grid accordingly is likely to weaken market integration with a decrease in price convergence. Booz & Company recently[1] estimated that there would be large benefits in having a more interconnected market (estimations are in the order of €2.5bn to €4bn per year). Indeed, more interconnections would help to alleviate some of the local network balancing constraints, and would allow optimizing the use of different generation and demand sources over a wider geographic area.

However, interconnections are very expensive: Cap Gemini highlights the fact that "it is hardly conceivable that electricity TSOs will be able to cope with the €140 billion investments required by 2020, as defined by the European Commission". An economic optimisation must be found between, on one side, perfect interconnections between Member States without any congestion and an all-time price convergence, and, on the other side, less expensive expenditures. Cost-benefit analysis must be done before deciding on a new interconnection to avoid wasteful expenditures.

Moreover, interconnection lines can have a significant effect on power prices across borders. Some countries will win more than others and the political and social acceptability of further market integration will require some more discussion about redistribution mechanisms.

(1) *Benefits of an Integrated European Energy Market,* report prepared for Directorate General Energy European Commission, Booz & Company, Amsterdam, Professor David Newbery, University of Cambridge, Professor Goran Strbac and Danny Pudjianto, Imperial College, London Professor Pierre Noël, IISS, Singapore, Leigh Fisher, London. Revised 20th July 2013, http://ec.europa.eu/energy/infrastructure/studies/doc/20130902_energy_integration_benefits.pdf

In all cases and nearly in all countries, a simplification and an acceleration of the application of regulatory rules for building new interconnections are needed.

Finally, production and consumption of electricity need to be balanced in real time at every point in the network. So far, European countries have different approaches both in terms of congestion management and in terms of connection charges. This highlights the lack of a coordinated approach toward sending appropriate locational signals to electricity market players in Europe. Failure to coordinate could increase the total electricity system balancing costs, and create tensions between different stakeholders as experienced recently between Germany and some of its neighbors. The issue is likely to grow as more renewables plants are connected to the European grid, since these plants are often located far from the areas with important loads – making it urgent to define a coordinated approach[1].

The need for generation adequacy assessments taking into account the economic parameters

The European Commission considers that the necessary tools to assess generation adequacy on the European level do not exist yet. This subject is currently on the agenda of the Electricity coordination group (which includes the Commission, the Member States, ACER and ENTSO-E). For the time being, they rely on ENTSOE analysis, which shows that there is overcapacity at European level except for some regions like South of Germany, but which doesn't take into account the economic situation and the non-profitability of gas power plants. Therefore, they don't take into account the fact that many operators have announced mothballing or decommissioning some of their gas plants.

Similarly, Eurelectric puts the stress on the fact that one of the drawbacks of the ENTSO-E generation adequacy outlook is related to the fact that it is based on the technical lifetime of generation assets and does not include the economic parameters of the existing and future generation. This might result in an overoptimistic assessment of generation adequacy, especially if much increased renewable output results in low load factors for back-up generation assets, which might hence be prematurely decommissioned for economic reasons.

ENTSO-E considers its generation adequacy assessments is based on the information submitted by generators not by the media. If decision of decommissioning were made and TSO duly informed it would be taken out of the assessment.

(1) Source: Fabien Roques's paper.

Conclusion: the need to act

The European electricity system is at a crossroad. Member States along with the European Commission need to clarify the aims of the integrated energy market and of the different European energy policies. When defining energy policies, Member States should ensure that they are consistent with one another without overlapping and that setting new policies will not undermine or compromise the others policies in force. For instance, regarding the 2030 objectives, it should be more efficient to make a clear distinction between the objectives and the means put in place to achieve them and to consider CO_2 emissions reduction as the main, if not the only, Climate target. But it should be done taking into account the calendar of climate change international negotiations, avoiding setting a 2030 European target prematurely ahead of the beginning of 2015 Paris negotiations on post-2020. EU accounts for less than 12% of world's emissions and a too ambitious objective, without border tax, would threaten its competitiveness. In fact, the main point is that Europe finds an agreement with China and the United States on an ambitious reduction target for those three economies (and on long-term finance). Secondary targets could be added only after being studied as coherent to the main one. In all cases, the tradeoffs between the different objectives would have to be studied. In the meantime, short-term recommendations can be made, the leitmotiv of these being to have a more coordinated approach.

First, as desired by the European Commission, the electricity target model needs to be completed for instance by extending the day-ahead market (scheduled in the next future) and by also working on better integration of shorter-term markets such as intraday markets and balancing mechanisms. If the objective of completing the integrated electricity market by 2015 is not likely to be met, Member States should nevertheless continue to work hand-in-hand and put the stress on intraday markets and harmonizing balancing approaches. A more interconnected market would also be beneficial as it would help to alleviate some of the local network balancing constraints, and would allow optimizing the use of different generation and demand sources over a wider geographic area. But, because interconnections are expensive, an optimum has to be found.

Then, an appropriate intervention is necessary to prevent carbon prices in the EU ETS from collapsing in order to restore the efficiency of the price signal to invest in low-carbon technologies. Introducing clear and stable long-term goals at 2030 is therefore essential, but should be done taking into account the calendar of climate change international negotiations. Other ideas must be studied: a floor price, as set by the UK, may be a good price signal for long-term investments, a central bank for carbon permits, as mentioned by Claude Mandil, could be a good way to manage supply of carbon permits with some adjustments.

Third, the renewables, which have reached technological maturity, should be driven by market mechanisms only. If needed, a temporary additional remuneration system (e.g. system of premium) could be granted. Regardless of the remuneration system, any

RES producer should be subject to the same responsibilities and liabilities as those of conventional energy producers; in the meantime, a first step would be to stop the feed-in tariff payment when wholesale prices are negative; a way to make RES producers take part to the balancing mechanism must also be implemented quickly. For the renewable technologies for which important progress are expected, financial supports should rather be devoted to R&D expenditures or for demonstration projects.

Fourth, if the actual generation adequacy outlook on electricity (between offer and demand) is based on the technical lifetime of generation assets, another adequacy exercise for the European Commission should include the economic parameters of the existing and future generation of power plants (to take into account the possibility that some back-up generation assets may be prematurely decommissioned for economic reasons).

A collective reflection is required to appreciate whether those modifications are sufficient enough to create good conditions for long-term investments and to ensure long-term security of supply. If the electricity market is not able to give the right signal for security of supply and long-term investments for the next twenty or thirty years, a central buyer, with a long-term vision, is then needed to secure long-term contracts

For many economists, governments will have to design capacity mechanisms to ensure that security of supply is met. Even if there's no academic consensus on that point, capacity mechanism may also be an answer to the missing money problem. In that case, a solution would be to define a European capacity mechanism (after a fine tuning of each country's and stakeholder's "burden" in term of capacities). But, the Member States' needs – for instance for base-load, peak or balancing capacities – are very different so that it will be very difficult to design a common mechanism for all Member States. Moreover, as such a mechanism would be very complex (the resulting price will be in particular very dependent on the constraint which is set), a second solution would be that the EU set common principles for these mechanisms while Member States define complementarities in their design with their neighbors.

In a more fundamental approach, the role of marginal costs pricing as the pillar of electricity markets should be revised. They give an efficient dispatching of means on a day-ahead basis. But, in a market with a great share of electricity produced from technologies with low marginal costs such as renewables, long-term reforms are necessary to let emerge economic signals allowing efficient investments. They need to be, as much as possible, the result of a coordinated reflection between the Member States in order to define jointly the tradeoffs between security of supply, climate change and affordability.

Demand side has to be taken also in consideration. Prices for customers are increasing quickly, generating on one side a fuel poverty that the crisis has initiated, and on the other side the occurrence of self-producers who are becoming free-riders of the system by escaping to its common charges. Common solutions must be found on the way these charges can be distributed on a social and economically efficient basis. More generally, the way demand side management and energy efficiency policies are led must be analyzed to fit to the other goals and not distort the market.

Nonetheless, the reinforcement of R&D cooperation between Member States is an important part of the European energy policy. The electricity landscape would be entirely transformed if for instance real electricity storage at low cost (other than hydraulic one) did exist for vehicles and for peak demand on the grid. To open new options for the future and restore Europe in its leadership in those fields, technological roadmaps must be precisely developed, to calibrate the Europe's and Member States' R&D effort and spending, mainly in new RES, energy storage, smart grids, energy efficiency…

European electricity markets: policy deficiencies, design deficiencies, and opportunities for policymakers

Marc Oliver Bettzüge[1]

1. Fundamental deficiencies of the political approach to the electricity sector

Paraphrasing a well-known dictum, one can say that "design follows policies". Therefore, before discussing questions of market design, one has to clarify the policies which the desired market design is supposed to implement. Hence, this paper starts by briefly reviewing the status of current policies for the electricity sector. Specifically, it will discuss political objectives, the choice of the basic regulatory paradigm, and the issue of subsidiarity between the EU and the Member States.

Objectives

Political objectives should be visible, balanced, credible, and consistent. Currently, there are no visible, let alone balanced, credible or consistent political objectives for the electricity sector beyond 2020 – neither on the European level nor within the Member States.

In the recent past, policymakers have focused their priorities on the ecological angle of the policy trilemma (environmental concerns, economic concerns, security of supply concerns). They have formulated quantitative targets for CO_2 mitigation pathways, for RES-E-shares and for energy efficiency whilst leaving the two other

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angles of the trilemma largely undiscussed. Such an approach would be justifiable only if there were no trade-offs (which is not the case) or if the ecological objectives were given absolute priority (which can hardly be rationalised given the intricate structure of the global GHG challenge). Hence, policymakers should be expected to actively manage the existing trade-offs present in the trilemma rather than accepting their attempts to ignore them. Insufficient balance between the policy objectives is a major deficiency of the current political approach to the electricity sector, also undermining its long-term credibility.

An important factor in managing the trade-offs present in the trilemma is the choice of the speed of transition. In particular, policymakers have to decide how fast the transition should take place. Obviously, the choice to move fast creates even more disruption when demand is suppressed and the economy is weak (compared to a situation with a growing electricity market and a buoyant economic climate). In general, the choice of speed should be reflective of the adaptability of the entire system, including, notably, the grid[1].

In this context, European and national policymakers should also clarify their objectives on the environmental angle itself. With flat demand and sufficient generation capacity, there must be an additional motive for forcing the electricity sector into rapid transition mode. Originally, this motive was a commitment to GHG mitigation in Europe as a positive element of global climate change negotiations. So far, this strategy clearly has not been successful. A revision of the EU's overall strategy for the global climate negotiations seems to be timely, including a thorough debate on the relative merit of unilateral commitments regarding the mitigation of emissions compared to other potential measures and activities inside the EU[2].

But even when maintaining a unilateral EU commitment to mitigation, policymakers need also to clarify whether and why they want to pursue additional objectives such as, e.g., the deployment of certain types of mitigation technologies. Thus, an important issue for policymakers is to clarify their position on technology choice. Standard arguments offered to legitimate such technology-specific support (such as considerations with respect to industry policy or social vs. private risk) are typically not

(1) For example, the rapid increase in intermittent RES-E capacity in Germany and Denmark has not been complemented by an equally rapid expansion of the transmission grid, leading to significant adaptation problems in the grids of Germany and its neighbouring countries. Thus, significant challenges were created for TSOs in maintaining voltage control and coping with loop flows.
(2) Such measures and activities could, e.g., include introducing and harmonising CO_2 taxes in the EU, limiting the extraction of fossil fuels in the EU (rather than their consumption), fostering basic research in a broad range of relevant technology domains (rather than spending a lot of money on the diffusion of existing technologies), introducing border-tax adjustments, or offering systematic transfer payments as a part of a potential "deal" with other world regions. None of these or further potential measures can be seen as the "silver bullet" for a successful contribution of the EU to the global climate negotiations. However, any effective negotiation strategy of the EU needs to consider and balance a portfolio of such activities.

convincing because they fail to clearly identify the market failure addressed by the intended state intervention[1].

Regulatory approach

The electricity sector in the European Union has been organised according to a liberalisation paradigm since 1998. Specifically, value-added steps that allow for effective competition have been liberalised (generation, trade, retail). However, some restrictions still remain, in particular on the retail level and in the Eastern European Member States. The grid, representing a natural monopoly, has been unbundled from the competitive sectors and was made subject to regulation. Non-discriminatory access to the grid is the cornerstone of the liberalisation paradigm and has been largely implemented[2].

Main objectives of the liberalisation policy were (i) the establishment of a *level playing field* for the industry within Europe (as a major driver for further European integration) as well as (ii) efficiency gains (from more intensified competition – both within- and cross-border – and from reducing monopolistic inefficiencies).

European wholesale markets, and the prices generated on these markets, are *the* pivotal element of the liberalised electricity market. These prices reflect the scarcity between supply and demand at any moment in time with high temporal resolution[3] and thus deliver important and reliable indicators for investors, operators, and consumers.

A high quality of such a coordination mechanism is of utmost importance for the efficient and effective management of a complex structure such as the electricity system. Without such signals, actions by market participants need to be centrally coordinated, e.g., by way of state-owned or state-regulated monopolies, as was the case in many EU Member States prior to 1998.

Therefore, there is a fundamental choice of approach to be made: coordination by competitive prices versus coordination by a central authority, e.g., by a monopolist. With the decision to liberalise the electricity sector, the EU has opted for the former of these two options. However, since 1998, policymakers have also found it attractive to

(1) For example, the argument put forward to support learning curves and to create blossoming industries (e.g., notably for RES-E) needs to be judged with caution. Market failure in the innovation chain exists only inasmuch as private gains from innovation cannot sufficiently be appropriated by the innovator. While this is typically true for basic research, thus requiring an active role for the state in supporting higher research institutions, this is generally not the case further down in the innovation value chain. In particular, it is most likely not true in the diffusion stage.
(2) However, implicit privileges for certain market participants still persist, e.g., for RES-E generators or certain industrial consumers in the German grid.
(3) For balancing the market in the very short term, wholesale electricity markets are complemented by regulated balancing markets.

distort competitive price formation in certain parts of the market, e.g., by regulating retail prices or defining fixed feed-in tariffs for certain generation technologies[1].

In this context, it has to be stressed that technology choice is *endogenous* in a liberalised market[2]. It is well known that the private incentives generated in open markets lead to superior results both in terms of innovation and investment decisions[3]. However, many policymakers (as well as their voters) have strong opinions about the relative merit of certain technologies, in particular regarding generation. Thus, they want to treat technology choice as *exogenous* and, as a consequence, interfere in the price formation mechanism, e.g., by granting fixed remuneration. The choice of objectives, therefore, must be consistent with the choice of regulatory approach.

Forcing certain technologies into the market on purely political grounds, however, is statically and dynamically inefficient: It leads to significant political rent-seeking, which further distorts policymaking and market expectations. In the beginning of such action, the distortion remains limited, making it rather easy for the policymaker to argue about its irrelevance. However, typically, any distortion to the price formation process generates more and more critical follow-on effects over the longer term, inviting policymakers to scale up the scope of their market intervention. Hayek, von Mises, and others have argued that such a spiral of state intervention into the workings of the price process will ultimately pave the way to central planning[4].

A major case study backing this contention is the development of the RES-E support mechanism in Germany[5], and the accompanying ripple effects in the competitive part of the electricity sector[6]. Similarly, the debate surrounding the introduction of national capacity mechanisms in almost all of the EU Member States is contributing to this process of renationalisation and recentralisation (the latter mostly on the Member Sstate level only).

(1) E.g., German renewable promotion system (EEG), see below, or the planned support for new nuclear power plants in the UK.
(2) Imposing a CO_2-certificate scheme, such as the EU-ETS, or a CO_2-tax does not alter this argument, as long as these are technology neutral.
(3) In this context, the hypothesis that European, let alone national, state subsidies can help certain industries to (sustainably) outcompete competition in the global energy arena should be seen as courageous, to put it mildly. The technologies, e.g., required to make the shale gas revolution happen in the US, have not received state subsidies. They have, however, made the global business case for RES-E much harder as a consequence.
(4) This observation is also referred to as the “oil stain theory”, cf., e.g., von Mises (1929), “A Critique of Interventionism”, or von Hayek (1944), “The Road to Serfdom”.
(5) Main drawbacks of the German RES-E support system include the lack of competition between technologies and locations, the lack of responsiveness of RES-E-investment to the power price, and the fact that TSOs have to bid RES-E-volumes into the market at a price of EUR -3.000/MWh rather than at their minimal economic value (which is EUR 0/MWh). Moreover, the system does not contain any stringent ‘sunset clauses’ which would serve to effectively limit the volume of potential RES-E-investments. A limit on PV expansion has been introduced; however, at 51.2 GW, this limit can hardly be regarded as stringent.
(6) E.g., a lively discussion about state support for conventional back-up capacity, as well as the introduction of phase-shifters by Germany’s neighbours, cf. below.

Thus, after the shift from regulated monopolies (i.e., central planning by the state or by regulated monopolists) to liberalised competition, the paradigm of European electricity market design has now rapidly progressed to an approach of *prima facie* competition in conjunction with more and more state-induced price interventions. However, in contrast to the 1998 liberalisation process, this development has not been initiated deliberately, or top-down, by the EU and its Member States but rather is the result of a variety of heterogeneous, idiosyncratic, and largely uncoordinated measures of Member State governments.

A major aspect making state-induced price distortions attractive to policymakers is of course their typical construction as a levy, exemplified by the German EEG: As the levy is not charged by the state, but has to be collected by retail companies as a cost component in the total power price, the blame for rising electricity prices has for a long time been attributed, at least emotionally, to the retailers rather than to policymakers. Hence, neither the distributional effects nor the trade-offs related to the cost have played a major role in the German political debate so far, although this seems to be changing at present[1].

Subsidiarity

Policies for the electricity market are not reasonably coordinated within the multi-level governance structure of Europe. Within the European internal market, many policy measures close to the heart of national policymakers (e.g., retail prices, technology support) create repercussions all across the market. The EU lacks the explicit competencies[2] needed to effectively and efficiently coordinate Member States' actions in order to reduce the negative fall-out from these interactions.

On the other hand, market structures and perceived national priorities for the electricity sector are still very heterogeneous across the Member States of the EU. Substantial harmonisation of electricity sector policies, therefore, seems very difficult to implement within the current governance structure of the EU[3].

In addition, state ownership in utilities that are actively participating in competitive electricity markets is pervasive across Europe, either by the national government (e.g. EDF, Enel, CEZ), by regional governments (e.g. EnBW), or by municipalities (e.g. RWE, Steag, or more than 800 municipal utilities in Germany alone). Given the

(1) In terms of political accountability, this way of quasi-subsidies can be strongly contested, as has been shown, e.g., by a ruling of the German Constitutional Court in 1994 regarding the financing of hard coal subsidies by the power consumers. At the time, the court ruled that the hard coal subsidies were to be paid for from the state budget rather than from the power consumer. If the same logic were to be applied to the EEG levy, the annual RES-E subsidies would consume roughly 5% of the federal government's budget.
(2) Except for potential restrictions on illicit state aid.
(3) The political problem at hand bears strong resemblance to the challenges within the Eurozone, where a single currency is not backed-up by sufficient harmonisation of economic policies and economic regulation.

important role of the state as a regulator and "market designer" of these competitive parts of the value chain, conflicts of interest are well imaginable and may hinder the development of an effective level playing field in Europe.

In a certain sense, therefore, Article 194 of the Lisbon treaty contains an inherent paradox when it calls for a stronger integration of the internal market while guaranteeing full national sovereignty over the energy mix. While reflecting heterogeneity between the Member States, it fails to organise subsidiarity in a way which is consistent with an integrated electricity market. Furthermore, although promoting the internal market (which is a paradigm based on competitive prices), the leeway it leaves to national Member States entails frequent Member State intervention into this very price mechanism.

2. Current market design and major deficiencies

Market integration

In general, wholesale markets and the corresponding power exchanges are by now well-developed throughout Europe.

However, major improvement potential on the Member State level still exists, in particular in some Eastern European countries where liquidity in the wholesale markets has not yet reached satisfactory levels. Further initiatives to open the markets and to generate more wholesale activities in those member countries would be useful. Markets in Central Western Europe, in the UK, and in Scandinavia, by contrast, can be seen as fully operational.

The integration of wholesale markets within Europe has made significant progress during recent years. For some borders, price differentials have almost completely vanished, while they still persist for others[1].

Remaining price differentials can result from either one of three reasons: institutional discrimination of cross-border trade, inefficient allocation of cross-border transmission rights, or insufficient physical transmission capacity (i.e., a physical bottleneck). Wherever market coupling between national power exchanges has been implemented, remaining price differentials can therefore – with a very high probability – be solely attributed to physical transmission bottlenecks.

Market coupling has already been implemented in the region Germany-France-BeNeLux-UK-Denmark-Norway-Sweden-Finland and for the DC-Link between

(1) Cf. e.g. ACER and CEER, Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas (2012).

Sweden and Poland. As next steps, it is planned to integrate Switzerland, the Baltic States and Iberia into this large coupled market region[1].

Overall, integration of European wholesale electricity markets can be regarded as advanced, especially in Scandinavia and Central Western Europe[2]. However, due to the unbalanced development of the generation mix across Europe (specifically due to increasing shares of intermittent RES-E in Germany and Denmark vs. continuing focus on conventional generation elsewhere), the level of market integration will most likely *decrease* as long as physical grid connections are not expanded[3].

Regarding efficient and timely grid expansion, the activities of ENTSO-E in developing a European 10-year network development plan have already delivered significant progress. However, major areas for concern are remaining. For example, the appropriate burden sharing for national grid projects with cross-border relevance is still all but solved. Moreover, it cannot be excluded that national TSOs (with mostly national ownership) apply different priorities in grid expansion than, say, a Pan-European TSO would.

The functioning of wholesale power markets

Power prices in Continental Europe currently range around 40 EUR/MWh on average, both on the day-ahead and the forward markets. Wholesale prices have drastically come down compared to the price level of 2008, both in average and peak hours.

In general, the low prices for electricity in Continental Europe should be seen as a reflection of the current balance between demand (decreased, in particular due to the economic crisis) and supply (increased both in conventional generation capacity and in subsidised RES-E in-feed).

Further reasons for the substantial decrease in Continental European electricity prices since 2008 include strongly decreased CO_2 prices (see below) as well as strongly decreased prices for hard coal (partially due to the strong decrease of gas prices in the US caused by the so-called ‘shale gas revolution’).

In addition, the strong increase in the feed-in of RES-E, in particular of electricity generated from PV (Photovoltaics), has substantially altered the structure of the price-duration curve[4]. In particular, on sunny summer days, the previous mid-day peak has

(1) The contribution of market coupling to market integration can, e.g., be assessed by observing the effects of integrating Germany with some of its neighbouring countries. Cf., e.g., Monopolkommission, Sondergutachten 65, Energie 2013: Wettbewerb in Zeiten der Energiewende.
(2) Cf. EU-COM „A functioning internal market“(COM (2012) 663 final) and ACER/CEER „Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas“ (29 Nov. 2012).
(3) In some instances, transmission capacities are even reduced by the installation of phase-shifting equipment which can disconnect two neighbouring markets in situations of high RES-E in-feed.
(4) It does not, however, seem to have a major impact on the average price level compared to the other factors mentioned.

basically vanished in Continental Europe. This development puts additional pressure on the existing conventional generation mix, in particular on such power stations whose business cases mostly relied on the existence of a strong mid-day peak in the past. An optimal generation mix with high shares of intermittent RES-E would include many more peaking units (such as OCGTs, Open Cycle Gas Turbines) than the current generation mix, which is largely a legacy from a rather different past.

The current price levels of electricity, fuels, and CO_2 certificates, as well as the current structure of the price-duration curve, imply that some existing generation units are cash-negative (i.e., not recovering their fixed operating cost), particularly gas-fired power stations. Moreover, many generation units are profit-negative (i.e., not recovering the depreciation on the initial investment), particularly the units invested in the recent past. Given the rather high degree of financial leverage, i.e., debt, in the sector, the current situation therefore has the potential to unfold into a major structural crisis.

The weak profitability of existing generation units should be seen as a direct consequence of the economic crisis on the one hand, and of the political support given to RES-E (in particular in Germany) on the other hand. Put differently, expectations formed by investors a couple of years ago regarding the development of demand and of RES-E-deployment have not materialised, implying stranded assets as of now. Notably, this situation occurred despite Germany shutting down almost 9 GW of nuclear capacity within weeks after the Fukushima disaster.

Given current overcapacity and little sign that the main underlying drivers (weak demand, state-supported RES-E build-up) will subside in the near future, conventional generators have started closing or moth-balling some of their capacity, and further such action has already been announced.

From a private perspective, the recent development in the electricity market has destroyed utilities' shareholder value, putting some of the utilities in a critical situation with respect to their balance sheet. In general, such down-turns are typical for capital-intensive industries such as electricity (or steel, pulp & paper, or many other such industries), and they are typically characterised by a consolidation of the industry structure.

From a societal perspective, the major risk associated with the current down-turn in the conventional generation sector is of course the potential drop in the capacity margin, leading to more frequent and more pronounced price spikes and maybe even to rationing of demand in the case that demand is not sufficiently price-elastic and hence has to be curtailed.

As of now, wholesale prices show no sign of such trend. Prices have barely moved, and there is not yet a marked increase in the frequency and/or size of price spikes. Also, forward prices do not show a significant increase in price expectations for the coming years.

From this angle, and from most projections of the supply-demand balance, one can conclude that there does not seem to be an immediate risk of insufficient generation capacity *on the wholesale level* (i.e., on the level of the bidding zones). However, it is of course impossible to deliver a proof that such a hypothesis concerning the future is false.

However, even if as of now there are no signs for immediate concern about generation adequacy on the wholesale level, wholesale generation capacity margins should still be closely monitored. The supply curve is rather flat at the point where it currently intersects with demand. Thus, it could be imagined that too many similar units are taken out of the market at roughly the same point in time, thereby creating an over-reaction of the supply side and thus a sudden lack of adequate capacity. Even if this would not necessarily lead to a blackout scenario, it would in any case entail a sudden increase in the price level which can hardly be properly anticipated by market participants.

Moreover, wholesale prices only reflect the (geographical) average of the demand-supply balance in a given bidding zone. By construction, wholesale prices are not able to render an insufficient generation adequacy transparent on a regional level *beneath* the scope of the bidding zone. As long as there are substantial bottlenecks within a certain bidding zone, insufficient regional capacity may remain undetected as long as only wholesale prices are observed[1].

Germany has introduced a discretionary mechanism to guarantee generation adequacy. In 2013, the German government released a directive[2] which allows bilateral contracts between the TSO and generators deemed to be "system-relevant" and which includes payments from the TSO to the generator in order to keep the generation unit running. The regulatory authority, Bundesnetzagentur, has to be involved throughout the process. Obviously, such a case-specific approach is suitable for avoiding critical situations in the grid, in particular if the number of generation units of concern remains small. But it does not provide a systematic solution to the

(1) Germany is a prime example for a critical mismatch between the geographical scope of the bidding zone (the whole of Germany) and the grid topology. In fact, the phase-out of nuclear capacity in 2011 has led to a significant imbalance between Northern and Southern Germany. Internal bottlenecks are now occurring much more frequently in Germany. As there still is only a single bidding zone in Germany, however, these bottlenecks require a much more frequent use of redispatch interventions by the TSOs, activating (out-of-the-money) power plants in the South and curtailing (in-the-money) power plants in the North. In order to be able to do this, sufficient generation capacity needs to be available in the South; however, this is capacity which is not profitable relative to the (average) German wholesale price. Unless the single bidding zone is split, further regulatory action is required to keep those power plants in the system. It has to be noted that the German determination to maintain a uniform bidding zone across the country even *increases* the pressure on South German generation because of the excess demand it creates from our Southern neighbours. Any solution that maintains a uniform bidding zone in Germany can counter this problem only by making use of systematic cross-border redispatch, i.e., by effectively enlarging the German price zone.
(2) Reservekraftwerksverordnung.

problem. However, before being dismissed as inadequate, costs and challenges of alternative and more systematic approaches need to be carefully evaluated.

The Continental European wholesale market currently also exhibits the unusual feature of negative prices for electricity in certain hours. Paying money to consumers to use a valuable good such as electricity is of course a clear sign of market inefficiencies. Firstly, due to the structure of the support schemes, intermittent RES-E is not fully curtailed in such hours, although this would be economically reasonable. Secondly, the demand side can obviously not fully make use of the negative price signal – partially because of a lack of flexibility, but partially also because it typically has to pay other cost components as well (grid fees, taxes, levies, etc.), such that the potential gain from using electricity at negative prices cannot be completely utilised[1]. Thirdly, the conventional supply side displays an insufficient degree of flexibility, preferring to pay someone to use the electricity generated rather than shutting down the plant, for example, because of schedule optimisation due to heat requirements in a CHP plant.

Retail level

In spite of the decrease in prices on the wholesale level, electricity prices in Europe still are substantially higher on average than in other world regions, in particular the US. Low prices for gas and for electricity currently support a renaissance of US industrial production, with investments by European companies in the US being a part of this trend.

Reasons include the higher fuel prices paid for hard coal (transport) and gas (no US shale) in Europe and the inclusion of a price for carbon in Europe. Further important cost factors for many electricity customers in Europe are the many additional state-imposed taxes and levies.

For the case of Germany, on top of the EEG-levy, the state has induced further cost components into the retail price, notably the electricity tax (at EUR 20/MWh, implying an equivalent CO_2 tax of roughly EUR 35/MWh at the CO_2 emissions factor of the German electricity mix in 2012), the concession levy for the grid, a CHP levy for subsidising CHP plants, and an offshore liability levy to finance the cost of delays in the grid connection between offshore wind farms and the onshore grid. Together, these cost components amounted to roughly EUR 100/MWh for households and to roughly 70 EUR/MWh for industrial consumers in 2012. Moreover, the state is collecting value added tax of 19% on all of these cost components. Thus, the end price paid by the consumer up to now is roughly twice as large as the economic cost entailed by generation, grid, and retail.

(1) In fact, it can even be overcompensated if flexibility is treated as a “bad”.

The substantial wedge between end customer prices and economic cost of procurement has several detrimental effects: It incentives inefficient self- production for self-consumption, both in the industry and on the household level, it leads to various undesirable distributional effects, and it stifles retail competition[1]. Moreover, given the current construction of grid fees and the various levies, the trend to self-produce threatens to turn into a self-promoting vicious cycle.

On the retail level, moreover, there still exists improvement potential for further European market integration, e.g., in terms of regulated prices or import/export tariffs, in particular in Eastern Europe.

The wide range of competencies still residing with national policymakers lead to a wide range of market design and tax regime choices across the EU. For instance, from the point of view of a Spanish customer, the electricity market (in the sense of prices and price structures) looks very different compared to the perspective of, say, a German customer. Pan-European retail or procurement strategies are thus being hampered. Therefore, this patchwork structure by itself is a major deficiency of the market design, effectively dividing the European internal market into 28 pieces and thereby stifling productivity and innovation.

GHG-mitigation

Prices for CO_2-certificates under the EU ETS currently range between 4 and 5 EUR/t of CO_2. The current price level is far below previous expectations at the time the cap was defined[2], and below estimates for the external cost of damage created by CO_2 emissions[3]. In essence, the certificate price should reflect the market participants' expectations for the tightness of the cumulative cap for the 2013-2020 period. Although there have been some irregularities in the trading of CO_2 certificates in the past, there is no substantial evidence supporting the hypothesis that the certificate market is not functioning properly.

On the contrary, several observations support the hypothesis that the EU ETS price correctly reflects the expectation that the market will not be particularly tight up to 2020. These observations include, e.g., a weak demand for CO_2-certificates in the wake of the economic crisis in Europe since 2009[4], a strong increase in the inflow of

(1) In addition, grid fees are calculated on the basis of energy and maximum capacity actually used. These design elements reduce the elasticity of consumers with respect to the wholesale price without any economic benefit since grid costs are basically fixed in the short term. Because of this distortion, e.g., industrial consumers in Germany find it hard to beneficially react to very low or even negative power prices in situations with high wind and solar in-feed.
(2) Cf. e.g. www.db.com/medien/en/content/press_releases_2007_3588.htm?dbiquery=null%3A%26%238220%3BCarbon+Emissions%3A+Banking+on+Higher+Prices.
(3) Cf. Tol R. (2009), "The economic effects of climate change", *Journal of Economic Perspectives*, 23(2), pp. 29-51.
(4) Excess certificates from the 2008-2012 period could be banked into the 2013-2020 period.

CO_2-offsets from CDM[1] projects realised at low mitigation cost, past and expected future Member State support for certain mitigation technologies (in particular, RES-E) suppressing demand for CO_2-certificates, and no political commitment on the 2020-30 period[2].

For the EU ETS, therefore, major deficiencies comprise the lack of firm political commitment to the mechanism beyond 2020, the scope and role of CDM as well as the discussion around set-aside/backloading, which threatens to further undermine the political credibility of the mechanism without significantly impacting the CO_2 price. On the latter point, there is insufficient explicit governance in the EU ETS for dealing with situations with unexpectedly low (or high) demand for certificates.

On top of the EU ETS, the EU has defined two other elements of the so-called "climate package", namely an increasing share of RES-E and an increased energy efficiency. Such additional efforts do not lower the EU's emissions in the EU ETS sector but only serve to lower the price of the certificates, at the same time inflicting additional cost on the economy because of the privileges that are given to those specific mitigation technologies (rather than letting the EU ETS market do the job of selecting the mitigation pathway on its own). In essence, e.g., the coal-to-gas option is crowded out by the generous support given to more expensive mitigation options such as RES-E[3]. In any case, by superimposing RES-E subsidies on top of the EU ETS, the EU is significantly increasing its CO_2-mitigation cost. A revision of this policy is strongly advised, starting with the definition of the corresponding objectives[4].

Moreover, the EU has left the implementation of the RES-E- and the Energy-efficiency directive to the Member States. While for energy-efficiency this might be defendable on the grounds of subsidiarity arguments, national RES-E support schemes clearly impose burdens on neighbouring countries and have paved the way for inefficient schemes aimed more at pleasing national constituencies rather than attaining the European RES-E objective in a cost effective manner[5]. Having a level playing field between RES-technologies and locations across Europe would generate enormous benefits in reducing the cost for attaining any given RES-E target. Furthermore, an integrated and thus larger market for these technologies would serve as an additional catalyst for innovative activity in this sector.

(5) Clean Development Mechanism.
(1) Hence, there exist no prospects for banking certificates into the next period, and hence the market likely assigns a positive probability to a situation where the CO_2 price will be zero at the end of 2020.
(2) In fact, the share of gas in the European electricity mix is going down rather than up (the 'gas-paradox'), and is expected to continue to decrease in typical business-as-usual scenarios.
(3) Cf. Section 1.
(4) For the important case of Germany in 2012, note that the average feed-in tariff paid to the installations supported under the EEG was EUR 189/MWh, while the average market value of the RES-E volumes sold on the power exchange amounted to EUR 67/MWh only. To cover the resulting cost differential, the German power consumer had to support the RES-E operators with a levy amounting to roughly EUR 13 bn in 2012. The levy taken from power consumers has constantly risen from EUR 2/MWh (2000, year of introduction of EEG) to EUR 36/MWh (2012) and EUR 53/MWh (2013). In 2014, it will increase further to EUR 62/MWh.

3. Opportunities for optimising European electricity market policies and design

Clarifying the set of objectives and the regulatory approach

First of all, policymakers should clarify and coordinate their objectives before introducing *new* interventions into the market. This can credibly only be achieved as long as policymakers explicitly take into account all inherent trade-offs and refrain from trying to micro-manage market outcomes.

Priority should be given to reducing regulatory risk by making long-term political commitments to objectives and regulatory design choices.

In particular, exogenous (political) price distortions on a national level are not compatible with long-term credibility of policymaking – at least as long as the EU and its push for integrating European markets continue to exist. If privileges for the implementation of certain technologies remain a part of the EU energy policy governance, they should be harmonised on a European level.

Moreover, even if policymakers were able to effectively coordinate on a European level, policymakers, or regulators, would most likely never be able to solve the central planning exercise required. The liberalised market is much better able to pick and integrate the multitude of existing and new technologies which will be part of the future European electricity market[1]. This is particularly true in times of rapid change, and when many different actors are involved in the decision-making process[2].

Thus, policymakers should make the internal European market the 'fixed star' of their future regulatory approach, in particular refraining as much as possible from distorting market prices, especially on the 28 Member State level. Hence, if national privileges for the implementation of certain technologies remain a part of the EU energy policy governance, they should at least be required to be non-distorting to the price mechanism.

Specifying the subsidiarity principle in European electricity policy

Currently, price distorting behaviour by individual Member States can only be addressed by the EU on the basis of general competencies mostly in the context of

(1) In particular, this will also include many small-scale technologies, which can be deployed as distributed technologies (on the supply side as well as on the demand side) and be virtually connected. The development of these technologies as well as of the IT required for connecting them has dramatically decreased the cost advantage of an electricity system based purely on large-scale, asset-heavy central power stations and, thus, the value of shielding such assets from competition.
(2) E.g., the coordination task becomes significantly more complex the more a few large, central generation units are replaced by many smaller scale distributed units, or the more prosumers are actively managing their own power supply/demand-balance.

illicit state aid. However, the debates surrounding, e.g., the German RES-E promotion scheme or the British plan for supporting nuclear illustrate the structural weakness on the EU level, at least in the context of the electricity sector. Thus, the typical counter-reactions of Member States do not leverage European competencies but rather mobilise national resources[1], thereby typically impacting the well-functioning of the internal market further.

In accepting the challenges to a full-fledged political union in the field of electricity policy, it should, however, be at least required that Member States agree to gradually reverse the detrimental spiral of the renationalising and recentralising of the European electricity sector by specifying the subsidiarity intended by the Lisbon treaty in a way that is consistent with the move towards a more and more integrated European electricity market.

Technology support is at the heart of the subsidiarity conflict between the EU (internal market) and the Member States (sovereignty over the energy mix). Hence, it would be most important to clarify the subsidiarity principle in the field of explicit technology support. For example, Member States could agree that any support they give to specific technologies is generally accessible to investors in other EU Member States as well, and that the support is given in a (largely) non-distorting manner, e.g., through tax breaks, quota systems, or premia. On the other hand, the EU would guarantee the Member States the sole right to the permitting process, with the exception of some minimum standards agreed on the EU level. Such an agreement could be framed as an amendment that specifies the rather general terminology used in Art. 194 of the Lisbon treaty.

Prime issue number one in this context is nuclear energy. The risks of the civil use of nuclear energy in Europe cannot be confined to national borders, nor can – in integrated markets – the benefits to consumer rents from keeping existing nuclear stations in operation. However, the producer rent from nuclear power stations mostly remains with the Member States, either directly (through nuclear fuel taxes or state ownership of nuclear power stations) or indirectly (through the taxes paid by the operator in the country of residence). Hence, there is an opportunity to optimise on the intra-European risk sharing around the use of nuclear energy in Europe. Without an explicit discussion of these issues, a major nuclear accident somewhere in Europe would most likely create enormous political tension within the EU.

Prime issue number two in this context is the support given to RES-E. As shown by many studies, Europe has significant opportunities in providing a level playing field for the investment into RES-E technologies. For RES-E, the crucial choice is between a CO_2 mitigation policy purely implemented through the EU ETS (generating higher prices and, among other effects, higher profits for the existing nuclear fleet across Europe, but leaving more room for competition between different mitigation

(1) Examples include, e.g., the installation of phase-shifting technologies or the introduction of national market interventions such as, e.g., capacity mechanisms.

technologies) and a policy using complimentary support schemes (*ceteris paribus,* reducing the EU ETS price and, accordingly, nuclear profits).

If Europe decides to go ahead with an explicit RES-E target beyond 2020, it should aim to attain such a target through a joint and harmonised support scheme[1]. In order to be cost-efficient, and thus maximise European synergies, such a joint European RES-E support scheme should be technology neutral, location neutral, and it should remunerate RES operators on the basis of 'wholesale price plus X'. Here, 'X' can be determined in various ways, e.g., by a joint European quota reflecting the respective common RES-E objective. Such a quota system, which is analogous to the EU ETS, can be implemented rather easily, especially since a system of certificates of origin has already been implemented in the EU. Moreover, a quota system would provide a simple way to accommodate different preferences about the RES-E target among Member States: Member states could differ in the quota they impose on the customers residing in their territory, with the weighted average of Member States' quotas leading to the joint European quota.

Even prior to having a joint RES-E support scheme, Member States could benefit from location-based synergies by pooling their RES-E targets and RES-E support mechanisms on a bilateral basis, as suggested by the EU RES-E directive.

Improving upon market integration

There are many opportunities to further strengthen the functioning of the European internal market. Most important, markets can be opened up further in Eastern Europe, interconnections can be improved physically and commercially[2], and bidding zones can be redesigned to reflect the topology of the grid in a more optimal way.

Further improvements – apart from the continued removal of commercial and physical bottlenecks – can be expected from the implementation of the Network Codes in the context of the finalisation of the EU-internal energy market by the end of 2014. Important aspects are, e.g., the introduction of optimal bidding zones (i.e., bidding zones which optimally balance the trade-off between liquidity (the larger the better)) and internal bottlenecks (the less the better). Moreover, the reduction of the time span between gate closure (currently day-ahead) and physical fulfilment would help to integrate larger shares of intermittent RES-E more efficiently.

Europe would benefit from more cross-border harmonisation in grid regulation and from a deeper cross-border integration of TSOs. Maximising the available cross-

(1) Interestingly, the EU has decided on RES-E objectives for the EU and the individual Member States for 2020, while leaving the implementation of these objectives strictly to the Member States.
(2) Further improvements to market coupling can, e.g., be achieved through the introduction of flow-based market coupling, which takes into account the loop flows existing in a highly meshed transmission grid. For all other borders, improvements can be attained by rendering allocation mechanisms more efficient, in particular by migrating to an implicit allocation mechanism, i.e., to market coupling.

border transmission capacity should be a clear priority for all European TSOs, independent of potential political or commercial interests to isolate the national market.

Furthermore, common rules for cross-border cost allocation for infrastructure projects of common interest should be established.

Moreover, there is substantial improvement potential regarding the harmonisation of balancing mechanisms and their cross-border accessibility. The new network codes are expected to bring significant progress, especially in this dimension.

There is a debate on how to integrate power wholesale trading into the context of new regulation for the financial sector (EMIR, European Market Infrastructure Regulation). There are worries that such regulation could stifle liquidity on electricity wholesale markets in an undue manner, which may even endanger the very functionality of these markets. This issue should be closely observed.

Securing generation adequacy

With respect to the introduction of capacity markets, there still is substantial empirical analysis required as to whether the 'missing money' problem really exists, or will exist, in the European internal market and, if so, what are the major causes[1]. Solutions to a potential 'missing money' problem should then be pin-pointed to solve the underlying causes and may include capacity mechanisms but could also consist of other measures such as, e.g., changes in the trading rules at the power exchanges, case-by-case decision making of the regulatory authorities[2], or additional activities of the cartel authorities[3].

In any case, the appropriate level to define adequacy standards would be the bidding zone level, ideally after rearranging bidding zones in an optimal way. The role of the EU at the European level, therefore, consists of formulating standards for the structure of such mechanisms and ensuring that they are not misused as a surrogate for illicit state aid.

(1) Major needs for empirical research comprise both the demand side (e.g., elasticity, DSM, level of maximum load to be guaranteed) and the supply side (e.g., shape of mid-term merit order, market structure in tight market conditions, role of cross-border interconnection, role of distributed generation).
(2) Cf. *supra* on the selective intervention mechanism by the BNetzA in Germany.
(3) In the context of capacity mechanisms, the wholesale market is often referred to as an „energy-only market". Strictly speaking, this nomenclature is misleading. On the wholesale market, traders trade blocks of energy by time, with the time dimension becoming shorter and shorter until physical fulfilment. In this sense, wholesale markets jointly trade energy and capacity and deviations from a block within the smallest time interval traded are then settled through so-called balancing mechanisms. A pure energy-only situation only exists on the retail level for customers without real-time meters and who pay an energy (and a capacity) price independently of the time of consumption. For Germany, this part of the market can safely be assumed to be much smaller than half of the total.

Regarding such standards for capacity mechanisms, they should be technology neutral, transparent, and non-distortive to the electricity wholesale market[1]. Moreover, capacity mechanisms need to be accessible in a non-discriminatory fashion (especially cross-border).

Furthermore, there should be guidelines on how to define and to compute "generation adequacy". For instance, it is fully insufficient to define just a certain peak load in the past as the minimum requirement for secured capacity in the system. In particular, adequacy standards by bidding zones should reflect the diversification effects from Pan-European trade, which should lower adequacy standards relative to a world with inelastic or inexistent imports and exports.

Improvements on the retail level

Throughout Europe, a revision of the state-induced components of electricity prices is warranted. In particular, traditionally, it has been assumed that household electricity consumption is a fixed factor and thus can be significantly taxed. The new opportunity of own-production on the small scale brought about by liberalisation and technological advances means that this assumption is no longer valid.

Harmonisation of the state-induced price components across the EU would bring additional benefits, especially to those electricity producers and consumers operating in several Member States. In general, power prices should closely reflect the true economic cost of generation (including the internalised price of CO_2 emissions), grid, and retail and should not be distorted by additional cost components. Furthermore, given the very high share of fixed cost in the grid, payments for grid use should ideally be based on maximum capacity *potentially* required rather than on energy or capacity used in a given period of time. Such a change in the grid fee calculation would help to make consumers more price-elastic to short-term changes in the electricity price.

On a more general note, there is substantial opportunity in rethinking the distributional aspects of the electricity market design. In particular, there should be a careful discussion on how to make use of the state income from the EU ETS (potentially realising a so-called 'double-dividend').

Improving upon the EU ETS

If the objective to mitigate CO_2 emissions in the electricity sector remains an essential part of the political agenda, the EU ETS should be strengthened and receive firm political commitment. In particular, caps for the period 2020-2030 should be defined as soon as possible and the future role of CDM should be clarified at the same time.

(1) Cf., e.g., the comprehensive capacity mechanism for Germany suggested and discussed in Elberg at al. (2012), "Investigation into a sustainable electricity market design (Summary)", available at www.ewi.uni-koeln.de.

Moreover, if based on the recent experience with the EU ETS during the economic crisis policymakers feel that the cap should be made more flexible in such situations, they should explicitly define such a flexibility mechanism rather than arbitrarily intervening into the market. Possible mechanisms to achieve this are, e.g., price floors/caps or the setting-up of an institution responsible for such decisions.

4. Summary and perspectives

In general, there is substantial economic opportunity from a more European approach not only to electricity market design but also to energy policy in general. Two related *political* issues emerge as central aspects to this task: the role and the definition of appropriate policy objectives on the EU- and Member State level, as well as the division of competencies between the EU and the Member States.

Therefore, the issue of improving the functioning of European electricity markets should not be regarded as primarily an *economic* issue of optimal market design. Rather, *political* issues are central to the challenge of removing the many deficiencies in the functioning of the European electricity sector and have to be solved prior to the question of appropriate market design.

The main elements controlled on the European level (competitive wholesale markets, EU ETS) are the cornerstones of the European regulatory approach and are, with minor issues remaining, well-designed by themselves. However, due to market distortions mostly induced by the individual Member States' policy measures (wholesale) and due to a lack of visibility beyond 2020 (EU ETS), their well-functioning is more and more put into question. Key challenges on the EU level, therefore, are the clarification and definition of objectives for the period 2020-2030, the strengthening of the existing pillars of the internal electricity market and the EU ETS, as well as further progress in terms of effectively and efficiently coordinating national regulation.

The alternative to a path of continued, deliberate integration (based on a sound application of the subsidiarity principle) would be a 'muddling-through' with more and more national interventions to counter the cross-border effects of the interventions of other Member States. With a very high probability, such a process would inflict growing cost for providing electricity to the European economy. While 'muddling-through' may likely continue to go on for several more years, it is clear that this approach is highly unstable, and policymakers will most certainly find it impossible to stick to it *ad infinitum*.

Thus, a redrawing of European electricity market design can only be effective as a joint effort between the EU and the Member States. Therefore, it would be helpful to explicitly rethink subsidiarity between the EU and Member States for the electricity sector. Article 194 of the Lisbon does not provide a satisfactory answer to this challenge, if only, because it is not sufficiently precise. It is well beyond the scope of this study to make explicit suggestions for a new and more precisely defined balance of subsidiarity between EU and Member States. However, from the analysis presented, it becomes clear that leaving the (exogenous?) definition of the energy mix to the Member State without sufficient EU guidelines and EU enforcement potential is not consistent with the well-functioning of an integrated internal market.

In this context, harmonisation of energy policies and corresponding market design will become the more important the more electricity markets are integrated between the respective Member States. Hence, even if an integration of energy policies along the lines suggested can – for political reasons – not be achieved across the entire EU-28 in a first step, it would be extremely helpful to achieve progress into this direction within those regional pockets within the EU-internal market that are already well-integrated. Therefore, one of the most important starting points would be an integration of energy policies *and* market designs between the countries of the so-called 'Pentalateral Forum', i.e., France, Belgium, the Netherlands, Luxemburg, and Germany.

In summary, actors in electricity markets face enormous challenges, most (although not all) created by incoherent and inefficient policies and design choices. Thus, there is substantial need for action by European and national policymakers to improve upon the framework given to the electricity sector.

The current situation and mid-term prospects for European electricity markets

Dieter Helm

1. The objectives of energy policy

The starting point for an analysis of the current European energy policy is the objectives. What are the questions to which it is supposed to be the answer? It might seem simple and obvious, but in fact at the heart of many of the problems besetting current energy markets is a fundamental confusion – and in some cases fundamental differences – over what the objectives should be.

It is fashionable to state that there are three: security of supply, low carbon and affordability. Yet this "trilemma" – how to achieve all of these three simultaneously – is far from straightforward. None of the three objectives is well defined. What does security mean? Some suggest this means self-sufficiency, yet a moment's reflection tells us that if in the last century Europe had pursued this, then not much economic development would have taken place. What would have replaced imported oil and gas? Next, what does low carbon mean? Is this an instrumental objective in respect of climate change or the binding objectives for European production of carbon? Is it conditional on others or unilateral? Over what time period should this be addressed? Finally affordability might mean low retail bills for customers, protection against fuel poverty, or it might mean industrial competitiveness. These are very different things.

It is easy to see why politicians do not want to define these objectives clearly. It requires painful decisions to be made. Security comes at a price, as does decarbonisation. But even more painful is the trade off between the objectives. Is security more important than decarbonisation? Is decarbonisation more important than affordability? Many claim that there is no trade-off – asserting that only a low carbon energy sector can be secure and cheap. But this is self-serving nonsense. The tradeoffs need to be defined – and across Europe it is notable that they generally are not.

The desire to avoid facing up to these trade-offs is bolstered by appealing to a whole host of sub-objectives. These include a variety of ill-defined aims, such as “green jobs”, “green growth”, and “industrial competitiveness”. Then there are overlapping objectives, such as cohesion and regional integration, which get linked to energy infrastructures. There are clearly military objectives which feed into security and strategic stocks.

Multiple, ill-defined objectives almost always lead to complexity and that in turn creates obstacles to the efficient functioning of markets. Each objective needs at least one policy instrument. The interaction of each on the others is rarely considered. As each new problem arises, the temptation is to graft on yet more interventions. The result in Europe is an extraordinarily complex and overlapping set of interventions, probably beyond anyone even to describe. Not only is the question to which European energy policy is supposed to be the answer ill-defined but the answers embedded in current policy are multiple, complex and have serious unintended consequences. As we shall see, the result is that Europe’s energy sector is not achieving *any* of the trilemma objectives.

2. The Historical legacy

Any energy system is the product of its past – and most investments are the result of decisions in contexts which are very different. The current structure of the electricity market in Europe is the product of the gradual evolution of national electricity systems and the gradual impacts of a series of European directives, notably those on the Internal Energy Market (IEM) and the Climate Change Package (CCP).

Historically, electricity supply began as a local matter with considerable input from local municipalities and local authorities. In the middle years of the twentieth century, most European countries moved to regional or national systems. France and the UK opted for integrated national publicly owned monopolies. Germany, the Netherlands and Sweden relied upon local and regional cooperation.

European electricity trading has gradually developed as the result of bilateral agreements, and in practice this focused on links between French nuclear and its neighbours and the sharing of hydro resources. For the most part, the European dimension of electricity has been noticeable by its absence. This remains largely the case.

The result is that Europe is still characterised by a large number of differing national market designs and the priorities of each country are reflected in the structure and organisation of their electricity markets. Despite over two decades of trying to create a simple European energy market, the national approach remains the dominant one. There is, as yet, no European market.

3. Attempts at European integration and the Internal Energy Market (IEM)

While coal and steel figured strongly in the formation of the European integration processes, electricity has never been seen as a core EU competence. It is still overwhelmingly determined at the national level.

The IEM proposals were an extension of the *Completing the Internal Market* process from the mid 1980s. Spurred on by liberalisation and restructuring in the UK, the Commission attempted to extent the principles of the broader internal market to electricity and gas after 1990. Early attempts floundered on the distinction between regulated and negotiated third party access and fierce resistance to liberalisation from French and German utilities, notably RWE, Ruhrgas and EDF (E.ON was not created until 2000). The French and German governments reinforced this resistance.

In the case of France, it was not surprising that, with its overwhelming commitment to nuclear and the associated sunk capital costs, the prospect of the aberration of long-term contracts and the exposure of the nuclear assets to spot competition and switching caused concern. The British experiment had demonstrated how vulnerable long-term nuclear investment would be. Indeed, as is currently being witnessed in Britain *volte-face*, long-term contracts turn out to be essential to nuclear investment unless underwritten by governments.

In the case of Germany, the politics of the key industrial *Lander* and the history of dependence on imported energy, notably from Russia, made energy a more serious matter of national concern than, say, for Britain with its abundant North Sea reserves.

Notwithstanding these national constraints the Commission ploughed on with the IEM, and by the end of the 1990s it had agreed key directives on liberalizing both electricity and gas markets. The key features were: regulated third party access, unbundling and liberalisation of supply.

Gradually EU member countries have been implementing the *letter* of the directives, though not all have followed the *spirit*. So slow has the progress been that 2014 is now the target date – a quarter of a century after the Commission started on this path. As we shall see below, developments in other areas of policy, and responses by the companies have, to a considerable degree, undermined the IEM, such that it is now more a sideshow than the main action the Commission envisaged for it. To the extent that competition remains an objective, it is the broader elements of European competition policy – tackling abuse of dominance, discrimination and state aids – which tend to dominate. Recent actions against Gazprom are a case in point.

4. The coming of the Climate Change Package

The Climate Change Package grafted a whole raft of policy interventions on top of the IEM process. These included: the EU ETS, the renewables directive, the energy efficiency directive (eventually) and the carbon target. In the process, the CCP transformed the structure and design of the market. Little or no thought was given to the relationship between the IEM and the CCP, and in fact the CCP has had unintended consequences which have significantly weakened the IEM.

The CCP is a mix of measures based upon the overall ambition of the EU to provide "world leadership" on climate change. If the IEM was a product of the liberalisation agenda of the 1990s, the CCP was a product of the boom years before the credit crunch and economic depression which kicked in from 2007/2008. As Europeans had got ever richer, and as politicians convinced themselves that the business cycle was a thing of the past, the costs of the CCP were regarded as easily affordable.

A further key assumption behind the CCP was that the rise in fossil fuel prices which had begun in 2000 would go on – that oil and gas prices would continue ever upwards, and indeed many political leaders supported the various "peak oil" hypotheses. Added to this were the concerns about dependency on gas imports from Russia, reinforced by the two Ukrainian crises in 2006 and 2009.

The assumption about fossil fuel price increases – important in making the case for the CCP – was that these higher prices would in due course render the renewables cost-competitive and hence any subsidies would be temporary. Indeed, investing early in renewables would, it was argued, give the EU a competitive advantage over economies like the US, which remained heavily fossil fuel dependent.

These two core assumptions – economic prosperity and growth; and rising fossil fuel prices – both turned out to be at best misguided almost immediately after the CCP was launched.

To these a third assumption turned out to important too – that nuclear power would continue to play an important role across the EU. The German *unilateral Energiewende* was, in particular, no part of the CCP package – indeed it was assumed that existing nuclear plant lives would be extended and that new nuclear would be fairly common across Europe, rather than being confined to Britain, Finland, France and some former eastern European countries.

5. The impact of the world economic and Eurozone crises

It was almost inconceivable back in the middle of the first decade of this century that the spectre of mass unemployment, major falls in GDP and the possible implosion of the Euro would become the backdrop to the IEM and the CCP. The economic crisis had significant impacts on the energy sector. It reduced demand sharply, reduced emissions through lower industrial output, reduced consumers' ability to pay for the CCP measures, constrained credit provision and left the incumbent utilities with weak balance sheets. The more general effect was to refocus political debate away from climate change towards jobs and competitiveness.

6. The impact of shale gas and the new world of fossil fuel abundance

The shale gas revolution in the US was entirely unforeseen by the architects of the CCP – though the IEM was conceived in a world of low oil and gas prices. Many European politicians initially denied there would be any effect, claiming that shale gas was a temporary and wholly US phenomena.

Shale gas has in fact turned out to be massive in its impacts, and only the first of a whole stream of unconventional fossil fuels. Its impacts stretch from the geo-politics of coming North American energy independence to the falls in world coal prices.

It is this latter effect, as US coal producers search for new markets as gas squeezes coal out of US electricity generation, that has had the most immediate impacts in Europe. Abundant cheap coal has been burnt in Europe's power stations, and indeed Germany and the Netherlands have led the way in building *new* coal power stations. The result has been a squeeze on gas in Europe and an increase in carbon emissions.

The indirect effect of the coming of shale is the large gap between US and European energy prices that has now opened up. Whilst few energy intensive industries have left Europe (so called 'carbon leakage') new investment in these industries is taking place in the US rather than in Europe. The US is re-shoring energy intensive industries, and Europe has little place in this investment activity. The knock-on impacts to Europe's economic growth may be significant.

The impact on coal and on investment is reinforced by the impacts on the prices of oil and gas. It is fashionable to claim that US gas prices will have no impact on world gas prices because LNG is more expensive than pipeline gas. The impacts will initially be modest, but the build up of US LNG exports will have impacts as yet poorly understood. In part this depends on whether US shale gas exports lead to an increase in internal US gas prices. But it also relieves quantity constraints. Already Japan has benefitted from a lack of demand in the US. US imports have fallen away. Further effects will come via the impacts on LNG investment in Qatar and Australia.

The longer-term impact of shale oil and gas will be geopolitical. The US reliance on the Middle East will decline. Its willingness to provide a military umbrella for the Gulf region will gradually decline. Europe's exposure will rise. There is a major security issue here for Europe, and the role of very geographically central countries like Turkey will be important for Europe's future security of oil supplies.

7. The impact of renewables on emissions

Renewables are the big winners (along with coal) from the CCP. The Renewables Directive has provided subsidies on a large scale, and because it has a short time period (2020) and is based upon target shares for energy rather than electricity, it is a binding constraint on electricity systems across Europe.

There have been three main renewable technologies deployed: wind, solar panels and biomass. It is important to recognise that none of these can make much difference to climate change. The first two are low density and intermittent – and there is not enough land and shallow seas to provide sufficient aggregate energy output against the growth of world energy demand. Furthermore since electricity's share of the final energy demand is growing, and will over time encroach into transport too, the gap between total demand and the contribution these technologies in their current forms can make will probably get bigger. Wind and current generation solar technologies are, at best, marginal in a context in which global emissions continue to rise – and have continued to rise since 1990.

Regarding biomass, the extent to which it is carbon neutral is open to serious debate. In the case of wood burning, since trees are in effect Carbon Capture and Storage (CCS) assets (they store carbon), there is, at best, a time lag. Where the wood is a waste product, there are often alternative uses, like the paper and pulp industry. The knock-on effects of displacing supply sources to these industries feeds into other carbon emissions. Some local wood sources may be better from a carbon perspective but none is strictly carbon neutral. Regarding energy crops it is much harder to make any serious case that these are genuinely renewable. It is extraordinary that there has been no analysis of the impacts of renewables on global emissions, accounting for the intermittency, the full carbon cycles and the substitutions of carbon production for carbon consumption that the consequent higher prices cause.

8. The impact of renewables on electricity markets

Given the overriding emphasis placed upon achieving the renewables targets, many EU members have not only provided subsidies to renewables but also given them priority access to the electricity networks. When combined with the peculiar cost characteristics of wind and solar – the marginal costs are zero – whenever these technologies generate, they displace everything else.

There are two consequences: wholesale electricity prices fall when zero marginal cost generation comes onto the systems; and by displacing other technologies, the intermittency of the renewables causes everything else to become liable to intermittency too.

It is this combination of reducing wholesale prices and imposing intermittency which has caused great problems for conventional electricity generation. These factors have made investment in conventional power stations much less attractive, and already seriously impacted on the major energy companies.

A new gas-fired power station cannot now rely on being able to run base load – and hence depreciate rapidly the sunk and fixed cost investments. In addition it now requires interruptible gas supply contracts – and therefore has higher fuel costs.

The impacts on gas have been further exacerbated by the fall in coal prices, which has led to a gas-to-coal substitution. As noted below, the carbon price has been unable to bridge the gap.

The result across Europe of this combination of policy measures (and the German nuclear decision) has been to switch from gas to coal, and from nuclear to coal. Gas power stations have been mothballed, new gas investments curtailed and emissions have risen as a result.

The overall impact has been to render investments in almost anything uneconomic – other than technologies supported by direct government-based feed in tariffs and contracts for differences. The investments in renewables (and in Britain in nuclear) require long-term contracts: IEM explicitly encourages short-term switching and hence undermines long-term contracts. Only if customers are *compelled* to pay will the long-term contracts stick – and compulsion is exactly what the IEM opposes through its liberalisation measures.

The renewables dimension of the CCP thus undermines the IEM. It is a fundamental conflict of objectives and policy design.

There are two ways out of this: either the CCP has to be made market-friendly (by reliance on market-based mechanisms and without specific technology directives) or the IEM has to facilitate long-term contracts and hence limit customer switching and liberalisation. If the former, the route is to replace the renewables directive with an effective carbon price. If the latter, then capacity markets organised by some central buyer agency will be required. The European dimension of the IEM can only be preserved in this context if the capacity market design is Europe-wide, and not as at present on a country-by-country basis. So far, the Commission appears unwilling to give up on specific renewables targets or to enforce a common design on capacity markets.

9. The EU ETS and the renewables and the electricity markets

As part of the CCP package, not only was the renewables directive designed to promote and protect certain chosen technologies, but it also had the EU ETS as its market-based mechanism.

The EU ETS relies on a carbon cap. This is the reason the EU has been so concerned to have a second commitment period for the Kyoto Protocol framework – as agreed at Durban. The cap sets the umbrella within which the EU ETS allowances are allocated.

Given the CCP set a 20% carbon target for 2020, and given the economic crisis and the structural decline of energy intensive industries in the EU, the price of carbon under the EU ETS should be inversely proportional to the likelihood of hitting the target. Indeed if the target is met, the price should be zero (unless there is another commitment period and there can be banking of emissions reductions between periods – or there is ex-post intervention to reduce the number of permits).

The Renewables Directive has further undermined the EU ETS. Since renewables reduce emissions in Europe (but not necessarily at the global level), and since the cap relates to total emissions, an increase in renewables reduces the EU ETS price which in turn encourages an expansion of the coal burn. In theory, the renewables are cancelled out by the EU ETS.

The EU ETS price has been volatile and low – too low to make any difference to either the dispatch order of existing power stations or to influence investment. In particular, the EU ETS has had no impact on the dash-to-coal referred to above, resulting in modern low-emission gas plants being mothballed to make way for old coal plants.

10. The coming of capacity crunch in some cases

For some European countries, there is now a cyclical need to replace power stations. Since the end of the 1970s and in particular following the sharp recession at the beginning of the 1980s, there has been a trend away from energy intensive industries. The fall of the Berlin Wall at the end of the 1980s exacerbated this trend. The result was that the relationship between energy demand and the demand for electricity changed. Much of the capacity built on the assumption of a strong positive correlation between electricity demand and economic growth turned out to be surplus to requirements. Hence, with the exception of nuclear France, investment requirements were much weaker, with capacity margins comfortable across much of Europe.

The economic crisis from 2007 further bore down on demand, postponing the need for new capacity.

From 2015/2016 the EU Large Combustion Plants Directive (LCPD) will bring about the closure of a significant amount of coal-fired generation in a number of countries, having already impacted on the hours these plants can run – unless they are fitted with anti-pollution equipment.

Early generation nuclear plants are beginning decommissioning in a number of countries, with Germany deliberately speeding up this process. Both Germany and Britain are on similar paths to close most of the existing nuclear capacity by the early part of the next decade, and both have already started the closure process.

11. Capacity markets

Now that investment needs are in some cases pressing, and with many energy companies in poor financial shape as a result of the large scale M&A boom of the last decade and the economic crisis, it has become apparent that there are few mechanisms to ensure the required investment under the IEM, and the CCP is undermining the investment incentives for conventional plant as described above.

Whilst the feed-in tariffs have provided the long-term contracts for renewables, there is no parallel mechanism to provide such contracts for conventional plants. Indeed, as described above, the IEM actively undermines any incentive to contract for the sunk and fixed costs of new investments. There are no deep, liquid, transparent and long-dated future markets to hedge the risks.

The result is a major effort in a number of EU members to graft long-term capacity contracts onto the existing markets.

In theory, capacity contracts are not inconsistent with competitive markets. But they do require a key intervention: someone has to set the required capacity margin, someone has to auction the contracts, and someone has to force customers to pay.

Whatever the precise institutional allocation of these interventions, the essence of this mechanism is a central buyer. It is ironic that the central buyer model was proposed and rejected in the debate which brought forward the IEM directives.

Given the separating out of a System Operator (SO) in the rules in respect of unbundling, it is inevitable that the SO is involved in this process. Competitive auctions to meet the required capacity margin can be run by a different body, but there needs to be enforcement of the outcomes of the auctions. Making customers pay must mean they cannot switch out of the obligation. Whether this is facilitated through an administered levy, by supplier obligations or by the use-of-system charges is an important but secondary consideration.

The auction design is complex, and the details matter greatly in the consequences for the IEM and the extent to which the process is national or European. The first issue is the domain – who can bid? Is it just certain technologies? Can FiT-subsidised technologies bid as well? What about the demand side? Storage? Is it just national or European?

Next comes the form of the capacity contract. Is this firm capacity or should it include intermittent capacity? Should wind farms have to contract with peaking plants to cover their intermittency and provide reliable capacity on demand?

On enforcement, should bonds be put up in advance? What should the penalties be – for example, if the extra contracted capacity is not needed? What should the penalties be based upon – power costs at the time?

There is a question of the term structure. How often should the contracts be auctioned? Over what period should the capacity be committed?

Any institution which then has the obligation to fulfill the contract could enter into the capacity contract, or it could require concrete physical investment to take place.

12. The return of central buyers and national energy policies

As described above, the CCP has undermined the IEM. National governments have gradually taken on the functions of a central buyer. National governments determine which renewables will receive which subsidies. Wind, solar, biomass and nuclear depend upon government policy interventions, not the market. The practical question is whether this development should be further advanced, or rolled back.

Rollback to a market-based determination of the level and type of investment is very unlikely. Indeed, for many of the current investments, governments are committed up to two decades ahead.

As the incentives of conventional technologies are blunted by the intermittence of renewables, governments will have to design mechanisms to ensure security of supply is met. This is where capacity mechanisms come in.

The policy choice now confronting the EU is whether to use competitive markets to deliver the capacity levels that governments determine, or to use the same sort of contract-by-contract approach currently used for renewables.

In principle the central buyer could be European or at each national level. Notwithstanding the advantages of taking an EU-wide approach, in practice the EU element – the renewables targets – has been of questionable value, and there is no evidence that national governments are likely to surrender security of supply to the European Commission. It is not going to happen any time soon, whether or not it is desirable.

The question then becomes one of coordinating national policies and looking for bi-lateral benefits to trading between Member States.

13. What is to be done?

Faced with the competitive challenge of shale gas, rising global carbon emissions and having chosen some of the most expensive low carbon technologies which cannot do much about climate change, Europe's high-energy costs are both an inevitable consequence of the CCP and the casualty of world market developments.

There are three possible ways forward, depending upon the weight given to the objectives. These are:

– drive on with decarbonisation on a fast-track timetable,

– develop capacity mechanisms to ensure security of supply, and

– focus on lowering energy costs, both absolutely and relatively.

If the EU wishes to continue to drive a rapid switch to current renewables, then it follows that there will need to be permanent subsidies for these technologies, and larger capacity margins to meet the intermittency. The EU should then accept that it is unlikely to host energy intensive industries, and that its consumers will face high energy bills.

Delivering 40% and then 80% and even 100% shares of renewables will require a massive series of ramp-ups of investment. It is unlikely that the private sector would finance this without further support. Indeed, it is probably that there would need to be direct government investment and guarantees. National governments would be the driving forces. State aid rules would need to be ignored.

In theory the renewables could be driven by market mechanisms. But in practice, given the differences in costs and the political and planning dimensions at the national level, governments will carry on picking “winners”. Any market-based approach would put an end to offshore wind in many areas and politicians would have to recognise the scale of their errors.

The problem with the (current) renewables-first approach is that it probably cannot be afforded. Any energy policy must pass two tests: customers must be able to pay; and if they can, they must vote for politicians who will force them to pay. The dash-for-renewables is likely to fail both these tests.

The second option is to focus on security of supply. Contrary to many advocates of the British model, and the IEM, security of supply will not automatically be delivered by the market. Security of supply is a system public good.

If security of supply is the overriding objective, someone has to fix the capacity margin and there needs to be payment for the provision of excessive supply relative to mean expected demand. This is where capacity markets come in. The requirement can be auctioned, and the bidders are likely to be those who can deliver capacity on a continuous basis (as opposed to most, but not all, current intermittent renewables).

If affordability and competitiveness are the overriding objectives, then the policy question is how to meet demand for a given – affordable and competitive – price. The budget then is fixed and given, and the task is to meet it.

Affordability and competitiveness drive automatically towards lowest cost. This means buying the cheapest fuel inputs, focusing on new investments which are lowest cost. Europe has choices here – it could burn coal, like China and India. It could develop shale gas, like the US. It could decide not to invest so heavily in current renewables, though it might invest in R&D to develop future renewables.

None of these options looks attractive. The real choice lies somewhere between these – by defining the tradeoffs between the trilemma of objectives. That should be the starting point for the reform of European Energy Policy.

European electricity markets in crisis: diagnostic and way forward[1]

Fabien Roques[2]

Introduction: context and objectives

Liberalisation of European electricity markets started with the 1996 Directive. Progress has been generally slow and most markets remain fairly concentrated and isolated, compared to the original plan to create a competitive pan European well interconnected market. Whilst the trend had been toward slow but consistent progress in the 1990s and 2000s, the last few years have seen a patchwork of national policies accumulating and creating growing distortions. For instance, policies in support of some specific technologies, such as renewables, remain a national remit and have taken very different forms throughout Europe.

In many ways, Europe's 2020 Green agenda has not been reconciled with Europe's objective to create competitive and integrated markets. The inherent trade-offs between Europe's climate and environmental objectives, and its other competitiveness and security of supply objectives, have not been identified properly. The issues with the 20-20-20 targets implementation are becoming apparent today as many Member States revisit their support policies for renewables, in order to contain costs for consumers and preserve the industry economic competitiveness. The current discussions on the reform of the failing European Emission Trading scheme also crystalise some of these tensions between different policy objectives.

(1) The author would like to thank the "Commissariat Général à la Stratégie et à la Prospective" for its support in undertaking this study. The author is also grateful to Pr. Marc Oliver Bettzüge (EWI) and Pr. Dieter Helm (Oxford University) for very insightful exchanges during the course of the study. The author would also like to thank the following people who provided useful comments on early drafts of the paper: Manuel Baritaud (International Energy Agency), Jean-Paul Bouttes, Renaud Crassous, Laurent Joudon (EDF), Dominique Finon (CNRS CIRED), Jan Horst Kepler (Paris-Dauphine University), and Thomas Veyrenc (RTE).
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The current issues with electricity markets therefore result from unresolved tradeoffs and inherent inconsistencies in the wider set of European and national policies. As a result, investments are plagued by policy and regulatory uncertainty and Europe risks both failing to meet its environmental targets, and locking in high electricity prices for years. The ongoing discussions on Europe's 2030 policy objectives should offer an opportunity to learn the lessons from the 2020 policy framework and design a more consistent approach going forward.

A radical reform of electricity market arrangements is needed, to make their design consistent with the wider European energy and environmental policies. Electricity markets liberalisation need not be considered as an end in itself, but rather as a mean to an end. Designing and implementing market arrangements which support the deployment of low carbon technologies at an affordable cost, whilst maintaining security of supply will require some significant changes to the current electricity market design that was conceived 20 years ago in a different context.

This report aims to document the issues at stake, analyze some of the critical tradeoffs in the design and implementation of liberalised power markets in Europe as well as the environmental overlapping policies, and explore some directions for reform. The report has three main parts.

The first part describes the current status quo and challenges associated with the long-term decarbonisation of the European economy:

- Section 1 sets the scene by describing the current challenges for the European electricity industry and the challenges associated with the long-term decarbonisation of the European economy;
- Section 2 quantifies the investment challenge for the electricity industry and shows how the current regulatory uncertainty undermines investments and will likely not deliver on the stated policy objectives;

The second part of the report focusses on the "extrinsic" issues which affect electricity markets:

- Section 3 reviews the wider context for electricity market liberalisation, which calls for a rethink of the European energy policy framework, including the recent developments in global energy markets, as well as the impact of rising energy prices on economic competitiveness;
- Section 4 presents the distortive effects of support policies for low carbon technologies and the issues with the European carbon Trading Scheme;
- The third and last part concentrates on the "intrinsic issues" with electricity markets:
- Section 5 details the experience to date with European electricity markets liberalisation, and highlights the achievements as well as the shortcomings of the liberalisation and integration process;

- Section 6 dwells into the "intrinsic issues" with European electricity markets and focusses on the missing blocks in the current sequence of electricity markets, namely the need for better signals for short term flexibility as well as long-term resource adequacy;
- Section 7 concludes and discusses directions for reform for a sustainable electricity market design and regulatory framework.

1. The electricity industry in crisis: distinguishing short-term issues from the long-term challenges

The industry faces big challenges in both the short term and long term. The current crisis accelerates the need for structural reforms of electricity markets, in a longer term context characterised by a profound transformation of the industry dominant technologies and business models.

1.1. The short-term challenge: a "perfect storm" affects thermal plants

The electricity industry is going through a violent crisis as several factors combine to create a challenging operating environment for thermal plants. The current overcapacity across Europe results largely from the impact of the economic crisis which has reduced the growth of power demand: whilst electricity demand had been growing on average by about 50 TWh per year in the EU 27 between 2000 and 2007 (or about 1.7% per year), electricity demand remained in 2012 about 130 TWh (about 4%) below the peak reached in 2008. Going forward, the industry faces the prospect of a "lost decade", as the slow economic growth anticipated combined with policies in support of energy efficiency, such as the 2012 European Energy Efficiency Directive, have the potential to further dent into power demand growth.

The policy driven additions of renewables, which have continued unabated in the past few years despite the economic difficulties, compound the effect of the crisis on power demand for thermal plants. As renewables often have priority dispatch, their electricity production reduces the net or "residual" load that thermal plants have to serve. Whilst power demand has dropped by 112 TWh (4%) between 2008 and 2012 in Europe, renewables production increased by 176 TWh, such that residual demand has dropped by 288 TWh. Table 1 shows that a structural break in trend is at play, as power demand slow recovery (about 0.5% growth per year over 2013-2020) will be largely outweighed by the growth of renewables generation of about 4.6% per year, leading to a drop of 1% per year on average of residual power demand over 2013-2020. In other words, policies to support renewables production actually displace generation from thermal sources, which compounded with the effect of the crisis on power demand has dramatically reduces load factors for thermal plants in Europe. Between 2008 and 2013, the average utilisation rate of thermal plants dropped from

50% to 37%, with more than half of the decrease due to policy driven additions of renewables.

Table 1 – Average annual growth rate for EU 27 of GDP, power demand, renewables production, and residual power demand (power demand net of renewables production)

CAGR*	2000-2007	2008-2012	2013-2020
GDP	2.3%	-0.3%	1.8%
Power demand	1.8%	-1,0%	0.8%
Renewables generation	2.9%	7.3%	4.6%
Residual Power demand	1.5%	-3.3%	-1.0%

*Compounded Annual Growth Rate

Source: IHS CERA

The final element of this perfect storm resides in the evolution of fuel, carbon and power prices. The oversupply situation that characterises most European countries has led to a collapse of power prices to about 40 €/MWh, far lower than the long run total costs of even the cheaper technologies. Whilst prices that temporarily reflect the short run marginal cost of production and do not allow investment recovery are normal in a transitional period of overcapacity in electricity markets, the worry is that current period of low prices will likely last as the development of renewables with low variable generation costs will likely put sustained downwards pressure on prices.

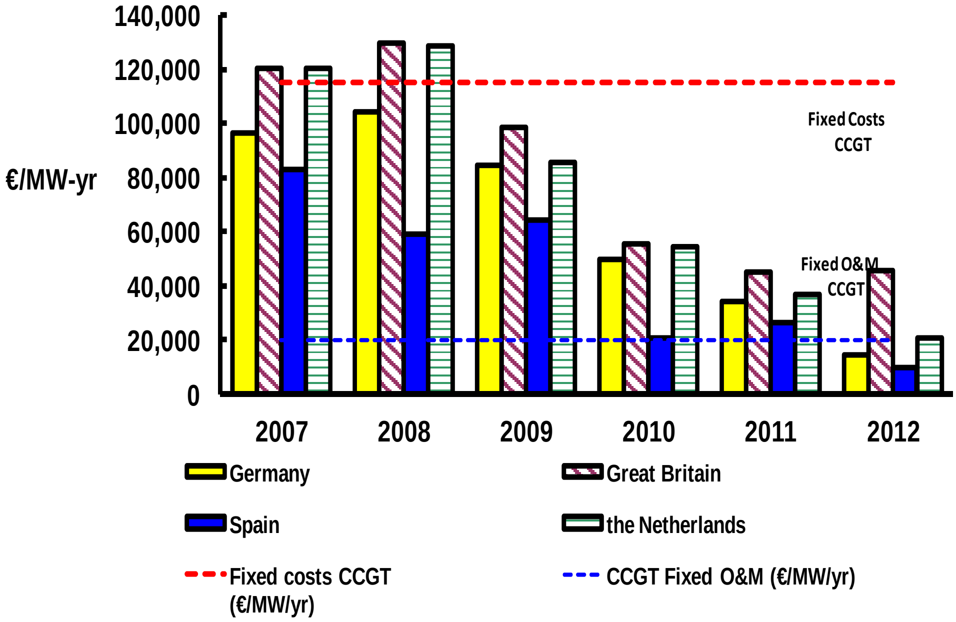
Within the current fleet in Europe, gas plants are relatively more affected by the storm as relatively cheap coal prices combined with the current low prices in the EU ETS make coal plants more profitable to operate than gas plants. Figure 1 shows estimated of the revenues of a typical combined cycle gas turbine (CCGT) in different European markets over the past five years. Revenues have decreased significantly, and remain well below fixed costs incorporating investment, and sometimes even below fixed O&M cost, indicating that many plants are likely to close. The result is that old coal plants get a "new life", whilst more efficient and relatively younger gas plants are left idle in many countries in Europe. Many operators have announced mothballing or decommissioning of some of their gas plants. As of mid-2012, there were about 38 GW of announced closures by the ten largest European utilities by 2015.

Going forward, the next few years will be decisive as a large part of the thermal fleet in Europe is under intense pressure. IHS CERA estimated in a recent study that out of the 330 GW of thermal plants in operation in EU-27 countries, about 113 GW are at risk of closure in the next 3 years (about 38%) in the absence of regulatory action[1].

(1) See IHS CERA Multi client study: Keeping Europe's Lights on: Design and Impact of Capacity mechanisms, August 2013.

Moreover, out of the 56 GW of gas plants at risk of retiring, three quarter (42 GW) would be less than 20 years old when retiring, raising the issue of compensation for stranded costs.

Figure 1 – Historical revenues for CCGTs compared to fixed O&M and total fixed costs (2007-2012)[1]



Source: IHS CERA Multi client study: Keeping Europe's Lights on: Design and Impact of Capacity mechanisms, August 2013, based on hourly EPEX Spot prices (Fr and DE/AT), APX UK, APX NL[2]

The paradox is that whilst there is currently plenty of capacity and healthy reserve margins in most countries, the risk is that an abrupt rebalancing of the market through massive retirements of plants could lead quickly to a more worrying situation from a point of view of security of supply. In particular in the UK and Belgium, where a lot of plants are scheduled to retire because of emission standards, governments and regulators have already rung the alarm bell. More generally, the key issue is that the current market and regulatory arrangements will likely not lead to an orderly and cost effective rebalancing of electricity markets, with excessive plant retirements which could in the medium to long term jeopardise security of supply.

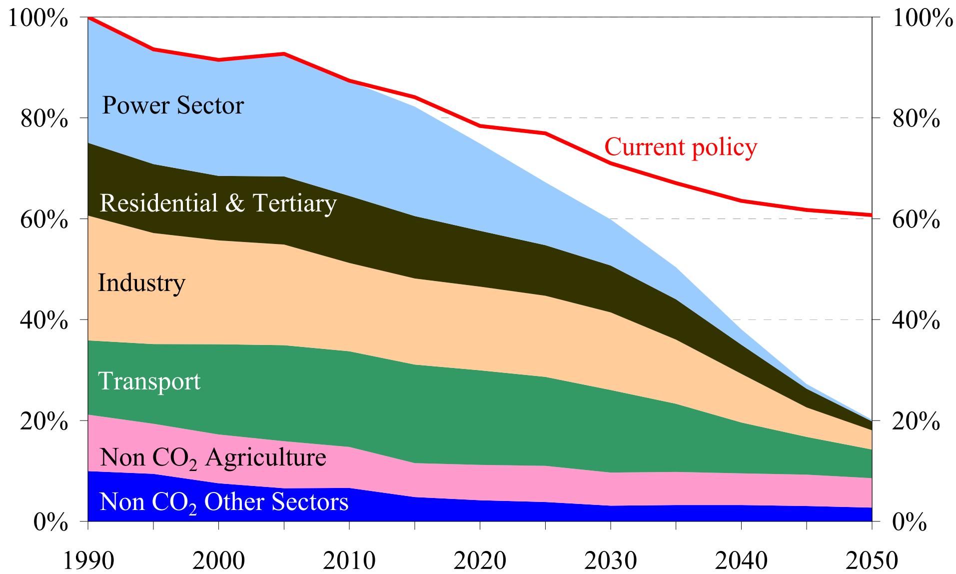
(1) Notes: Sum of revenues made for a 55% efficient CCGT when hourly spot > variable costs. Variable costs based on gas spot prices (NBP for UK, TTF for NL and BCT for Germany).
(2) Thermal plants throughout Europe struggle to be profitable as they face a perfect storm: low power demand combined with the growth of renewable power generation, reduced running hours. Low power prices and spreads further add to the pressure on plant revenues pushing plant operators to consider retirements, threatening security of supply. This IHS study examined capacity mechanisms throughout Europe and evaluated the impact on power prices and plant revenues.

1.2. The long-term decarbonisation challenge: an unprecedented transformation

In the medium to long term, the electricity industry in Europe faces the prospect of a profound transformation. The European Commission presented in 2011 its Roadmap for 2050 which envisage a decrease in CO_2 emissions from the European economy ranging from 80% to 95% (see Figure 2). The decarbonisation of the power sector is central to this objective, as the power sector represented in 2012 about 37% of the total CO_2 emissions in Europe, but also because the power sector is believed to be one of the sectors where the transformation could take place in the fastest and most economical way. Indeed, the 2050 roadmap recommends that emissions from the power sector be dramatically reduced as early as 2030 (Figure 2).

The decarbonisation of the power sector within the next two decades would represent an unprecedented transformation in terms of ambition and pace for the power industry. Deep uncertainties remain, however, on the credibility of Europe's engagement toward the decarbonisation of its power sector. Some countries within Europe oppose such transformation on the grounds that it would represent a too costly economic burden at tough economic times, whilst others question the rhythm of the transformation and whether the costs associated with it would be sustainable for both European consumers and for the competitiveness of Europe's economy. Poland for instance vetoed the 2050 roadmap on 15 June 2012, as the decarbonisation objective did not include references to the international context.

Figure 2 – European Commission 2050 decarbonisation Roadmap: Evolution of CO_2 emissions from the different sectors, 1990-2050



Source: European Commission, A Roadmap for moving to a competitive low carbon economy in 2050, March 2011

Moreover, there is also uncertainty on the costs of decarbonisation as most of the clean technologies are still in their learning phase. The implicit assumption in the European policy objective is that clean technologies will become eventually cost competitive. This justifies early investment in the technologies to go down the learning curve and rip the benefits when the technologies are mature. However, the learning rates and eventual cost or production is unknown, creating some significant risks for both policy markets and market players. Most importantly, technology ruptures along the way are likely and could lead to very a different future – for instance, a technology breakthrough on the electric battery side or on the processes to produce and store hydrogen could dramatically affect the future of electricity systems.

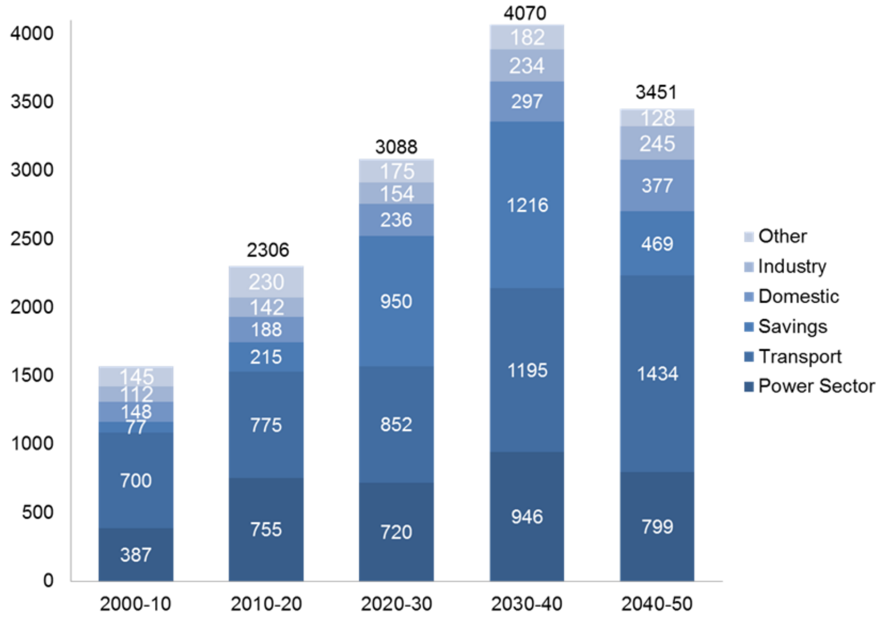
The deep political and technological uncertainties create a very uncertain context for the transition toward a low carbon electricity sector. Market players and regulators alike have to adapt to a changing environment and define a policy and regulatory framework that will be robust to a range of possible pathways regarding energy costs, the speed of technological progress on low carbon technologies, as well as a global agreement on climate change.

2. The investment challenge: the power sector is not "investment grade" anymore

Whilst the electricity industry faces deep short term and long-term uncertainties, significant investments will have to be made in both the short and long term to decarbonise the sector and renew ageing infrastructure. The key issue is that a range of policy, regulatory, and market uncertainties undermine the prospects for investment in the European electricity sector.

In its recent study "Power Choices", Eurelectric estimated that the total investment in power generation over 2010-2050 would amount to €1.75 trillion (in 2005 money terms), whilst investment in power grids over the same time frame would amount to €1.5 trillion. This corresponds to a range between 40 and 60 billion Euros per year of investment in the European power generation until 2050. The total energy costs are estimated to increase from about 10.5% of European GDP in 2010 to about 13% of European GDP in 2025. Figure 3 shows that in addition to this, significant investments will also be needed for energy efficiency and in the transport sector to decarbonise the European Economy.

Figure 3 – Investments required to decarbonise Europe's economy by 2050
(10 year periods, in billion €2005)



Source: Eurelectric Power Choices Reloaded Study (2012)

2.1. Falling profitability and financial constraints of the traditional investors

In an increasingly global economy, fierce competition for capital means that the power sector in Europe will have to compete to attract funding with other investment opportunities globally in a range of other sectors. However, the profitability of the sector has fallen in recent years. Figure 4 shows the evolution of the return on capital employed and of the cost of capital for 10 largest utilities over the past 5 years. The two lines are getting dangerously close, which implies that the ability of the sector to create value is endangered. The difficult environment for thermal plants plays a big role here, and several European utilities have made public statements on the current difficult investment climate, calling for major reforms. In practice, European utilities themselves are looking at better investment opportunities abroad, and a growing share of their CAPEX is invested outside of Europe.

One additional source of concern is that the main traditional investors in the electricity sector – European utilities – are in a weak financial situation as they enter into a massive investment cycle. Figure shows that the total net debt position of the 10 largest European utilities nearly doubled over the past 5 years to reach about 280 billion Euros. This is largely the result of the consolidation of the industry in the early 2000s. This implies that European utilities will only be able to contribute to equity financing of a small portion of the 40 to 60 billion Euros per year in power generation needed in the next decades.

Figure 4 – Return on capital employed (ROCE) and weighted average cost of capital (WACC) for 10 largest European utilities (2007-2012)

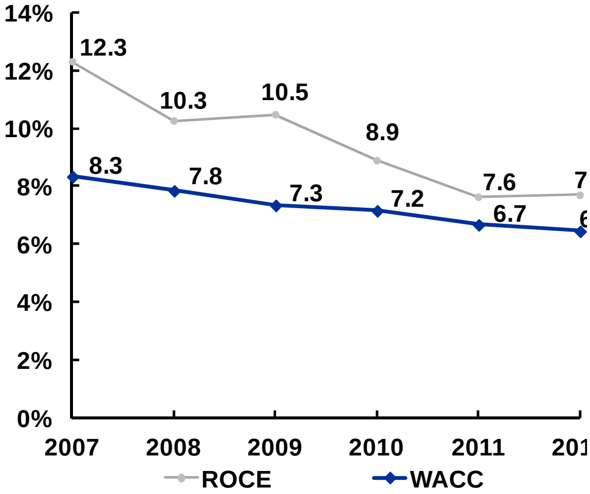
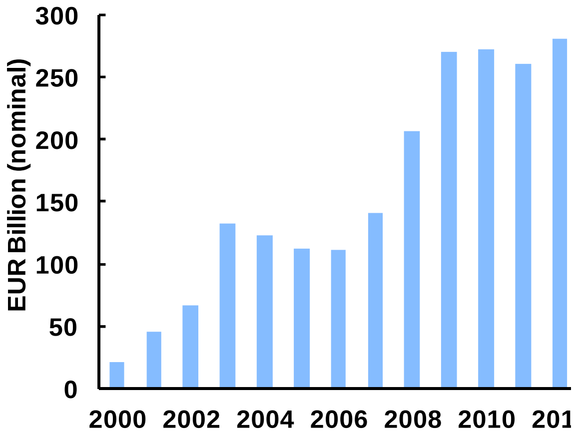


Figure 5 – Net debt evolution of 10 largest European utilities (billion Euros)



Source: IHS CERA 2012 European Policy Dialogue final report[1]

2.2. Closing the “financing gap”: rethinking the regulatory framework to reduce risks

What is clear is that the current regulatory framework and market are not fit to attract the massive amounts of capital that are required to finance the transition to a low carbon economy. The risk is that an inappropriate regulatory framework would fail to deliver the investments required to either maintain security of supply and/or deliver on the ambitious EU decarbonisation policy objectives.

A rethink of the regulatory framework is therefore needed to reduce risks for historical investors, but also to attract different sources of investors. Given the current weakness of European utilities’ balance sheets, the historical investors in the sector, new sources of capital will be indeed being needed. Whilst decentralised generation technologies will contribute to a sizeable part of the investments going forward, utility scale investments will still be needed to finance the upgrade of transmission and distribution infrastructures, as well as of conventional generation.

Financial players have shown a consistent interest in investing in the energy sector in Europe, and could be key players to facilitate the financing of utility scale infrastructure and generation investments going forward alongside utilities. Funds

(1) Drawing on the deep knowledge and experience of experts from IHS and its member base of academics, policymakers, and other key stakeholders, the IHS CERA European Policy Dialogue is an ongoing research effort designed to inform and help shape the development of sound energy policy.

taking a long-term perspective are particularly well suited, such as pension funds or sovereign wealth funds.

In order to attract large amount of equity investment into the power sector, financial players will need to be reassured about the technology and policy risks associated with investments in the European electricity sector. Funds that are ready to take on the lower ends returns on investment that have been typical of the utilities sector in Europe will also want a very secure risk profiles – which means that the key sources of risk on the regulatory, technology, and market side will have to be mitigated and/or transferred into other parties. Closing the "financing gap" will therefore require a rethink of Europe's regulatory framework to reduce risks for investors.

3. The changing context for electricity market liberalisation – new policy priorities and changing global energy markets

Whilst electricity market design has been a subject of much attention for the past two decades, a number of recent developments combine to accelerate the need for electricity market reform. Changes in European energy policy priorities, in the technology cost profile, as well as the recent developments of global energy markets and of the international negotiation on climate change create a very different background for electricity market design compared to the times when the current markets were defined, some 20 years ago.

3.1. Changing European energy policy priorities: combining liberalisation with decarbonisation and security of supply

European energy agenda has different and sometimes conflicting policy objectives: competitiveness, security of supply, and the environment. The policy priorities of the European Commission (EC) have evolved over time in Europe in a significant way.

In the late 1990s and early 2000s, policy efforts focused on creating the regulatory framework and common rules for the internal market in electricity, with the two key milestones being the December 1996 Directive (Directive 96/92/EC) and the June 2003 Directive (Directive 2003/54/EC). The European Commission launched an inquiry into competition in gas and electricity markets in 2005, and the final report published in January 2007, reckoned that progress towards implementing open and competitive electricity and gas markets in Europe had been disappointing. This led to a new legislative package, the so called "Third Energy package" proposed by the EC in 2007 and finally adopted in July 2009. The package, among other things, dealt with unbundling of transmission networks and generation, and established National Regulatory Authorities in each Member State and implemented an Agency for the Cooperation of Energy Regulators (ACER).

The focus of European energy policy in the mid-2000s turned onto the environment, as EU leaders set in March 2007 a set of targets for a low-carbon economy, which then was implemented through a set of Directives in 2009 often referred to as the "Climate and Energy Package". These targets, known as the "20-20-20" targets, set three key objectives for 2020: i) A 20% reduction in EU greenhouse gas emissions from 1990 levels; ii) Raising the share of EU energy consumption produced from renewable resources to 20%; iii) A 20% improvement in the EU's energy efficiency. More recently, EU leaders committed to reduce Europe's greenhouse gas emissions by 80-95% by 2050 compared to 1990 levels. In 2011, a 2050 Roadmap was published which explores alternative pathways in different sectors for decarbonizing the European economy.

In recent years, however, security of supply and competitiveness have come back to the forefront of the European energy policy agenda. The Russian-Ukrainian gas crisis of January 2009 which led to supply disruptions in several Member States reminded Europeans of their dependence on imported gas and led to revived discussions on both a common approach toward energy supplies from external countries and a strengthened set of criteria for ensuring security of energy supplies within the internal market. On 16 July 2009, the European Commission (EC) adopted a new regulation to improve security of gas supplies in the framework of the internal gas market[1]. In September 2011, a Communication on security of energy supply and international cooperation was adopted, setting out a comprehensive strategy for the EU's external relations in energy[2].

In the past couple of years, the economic crisis has imposed closer scrutiny on the cost implications of some of the climate and green policies, and concerns have grown that the uncontrolled deployment of low carbon technologies could both undermine European's economic competitiveness and raise concerns about security of supply. The Green Paper "A 2030 framework for climate and energy policies" (COM(2013) 169, 27/03/2013) represents an inflexion point in European energy policy that clearly heralds competitiveness and affordability as the key issue for the years to come. The consultation on the 2030 policy framework initiated a discussion on Europe's post-2020 energy policy and raised a number of questions regarding the "type, nature and level of climate and energy targets for 2030", the "coherence between different policy instruments; competitiveness and security of energy supply"; and the "distribution of efforts between Member States".

(1) Regulation (EU) No 994/2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC.
(2) European Commission (2011), Communication "The EU Energy Policy: Engaging with Partners beyond Our Borders", COM/2011/539.

3.2. The changing global energy markets context: the competitiveness imperative

Since the 2008 European Green Package was implemented, there has been almost no progress on the international scene toward a global agreement to mitigate climate change. The UNFCCC negotiations since 2008 have demonstrated the challenge of setting up a globally binding agreement. This has fired back on Europe's ambition to decarbonise its economy, as many doubts have been raised about such unilateral commitment and the costs that it would impose on the European economy, should other countries not follow suit with comparable engagements.

Some other significant changes in the global energy policy landscape are worth flagging. The discovery and production of large quantities of shale hydrocarbons in the US has largely changed the global energy market dynamics. Whilst the US natural gas production had been declining until 2008, and the US was anticipated to run into a large natural gas importer, the US is now foreseen to be self-sufficient by 2020[1]. Over the past three years, growth of unconventional gas production has been fastest than in any other country.

The shale gas revolution in the US has had consequences on the European economy through the global energy markets nexus. The pressure on oil indexed gas supply contracts has led to renegotiations with Europeans suppliers, which brought natural gas prices purchased though long-term contracts closer to market prices. The surplus of US coal production that is not being used anymore by power producers in the US has been exported and contributed to the downward spiral of international steam coal prices over the past few years – which explain the revival of coal fired generation in Europe.

Moreover, the ramifications of the shale revolution stretch into the broader issue of costs and competitiveness. By halving natural gas prices in the past five years in the US, shale gas has contributed to creating a significant cost advantage for locating some industries that are energy intensive or rely on natural gas as feedstock in the production process. The indirect effect on the price of electricity in the US versus Europe is also worth noting, as Europe has become much more expensive. Electricity and gas prices in Europe come at a significant premium to the prices in developing countries but also compared to other OECD countries, to the exception of Japan.

The recent 2030 Green Paper from the European Commission reckoned that the EC *"must reflect a number of important changes that have taken place since the original framework was agreed in 2008/9: the consequences of the on-going economic crisis; the budgetary problems of Member States and businesses (…); developments on EU and global energy markets, including in relation to renewables,*

(1) See IEA World Energy Outlook, 2012 edition.

unconventional gas and oil, and nuclear; concerns of households about the affordability of energy and of businesses with respect to competitiveness; and the varying levels of commitment and ambition of international partners in reducing GHG emissions."

The implications for electricity market design and the continuation of electricity market integration of the changing policy priorities in the European energy policy have yet to be identified and debated. This change in policy context is likely to have profound implications as creating a competitive liberalised internal market is not an end objective in itself anymore, but should instead serve the two other policy objectives – namely ensuring the safe and affordable supplied of energy to European citizens, and working towards the long-term decarbonisation objective. In other words, whilst the main objective of the previous directives on the internal energy market were to create a common market and to foster competition, the market design and regulatory structure will need to be rethought as a mean to an end – which will most likely lead to different types of arrangements.

3.3. Controlling the cost of clean technologies: pacing the energy transition

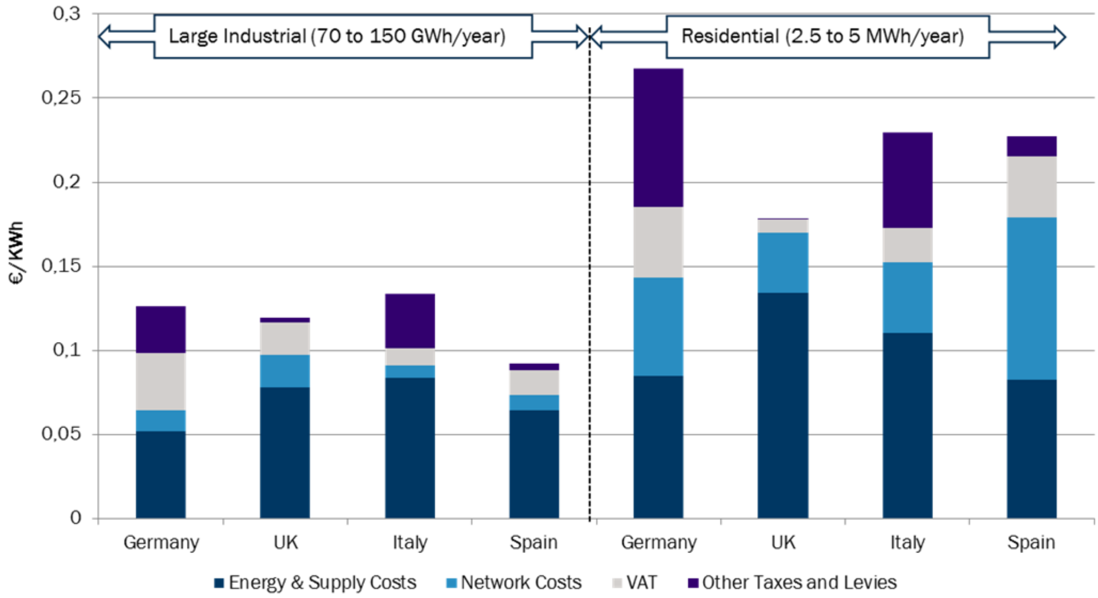
The economic crisis that has been characterised the past few years in Europe has led many governments to question the affordability of the energy transition toward a low carbon electricity system. The impact of rising electricity prices and the economic crisis has led to a significant increase of energy poverty in the past few years in Europe. A recent study from EPEE estimated that that 50 to 125 million people in Europe suffer from fuel poverty[1]. Rising electricity prices for industrials have also been a source of concern and are believed to adversely affect the competitiveness of the European economy.

One issue which has become center stage in the policy debate concerns the split of the burden of the costs of decarbonizing the economy between the different end users of energy. There has been little research on distributional issues, and European countries have chosen different approaches. In Germany for instance, the EEG legislation largely exempts large industrial users from the electricity price premium associated with the support of renewables, such that small enterprises and retail consumers actually bear the bulk of the costs of the energy transition. In France, in contrast, the cost of supporting renewables has been spread on a wider customer base through the CSPE. A similar issue is at stake with the definition of the sectors at risk of carbon leakage in the ETS. Figure 6 shows a comparison of end user prices for

(1) Fuel poverty is here defined as "a household is in a situation of fuel poverty when it has to spend more than 10% of its income on all domestic fuel use, including appliances, to heat the home to a level sufficient for health and comfort." See www.fuel-poverty.org/files/WP7_D26-4_en.pdf.
See also Walker R., Thomson H. and Liddell C., *Fuel Poverty 1991-2012*, Commemorating 21 years of action, policy and research, http://fuelpoverty.eu/wp-content/uploads/2013/03/Fuel-poverty-anniversary-booklet.pdf.

different categories of users, and highlights the different breakdown of the electricity price in the different countries.

Figure 6 – 2012 retail price breakdown for residential and industrial end consumers



Source: Eurostat

A second important issue is the pace of the decarbonisation of the European economy. A number of European countries including Germany, Spain and Italy have recently reduced generous support schemes for renewables which led to spectacular – and sometimes uncontrolled – deployment of renewables, particularly solar PV. Respectively 7 GW and 5 GW of solar PV were installed on average per year in Germany and Italy over the past three years. This solar PV boom was triggered by generous feed in tariffs guaranteeing a comfortable rate of return for investors – but also locking in 15 to 20 years contract an additional support costs to be paid by electricity consumers. The cumulative effect of the multi-year contracts to support renewables does not appear sustainable based on current trends. IHS CERA estimated that support costs for renewables in Europe have risen to 30 Bn€ in 2012, and would reach 49 Bn€ in 2020 based on current market trends. Based on current trends, annual renewables support costs would double across EU27 from €30 billion in 2012 to over €60 billion in 2035.

Most importantly, this important spending on the deployment of renewables technologies in their learning phase contrasts with the lack of funds available for research and development (R&D) in energy. In real terms, public spending in Europe on energy remains well below the amounts spent in the 1980s, and this does contrast with the industrial policies of other countries such as the US or Japan, which focus a greater share of public spending on R&D. Given the uncertainties on the costs and future progress of the different clean technologies, an optimal policy mix would need to be geared toward R&D and reduce spending on deployment. In 2007, the European Commission launched a strategic energy technology plan (SET plan) which aimed to coordinate better the different national efforts to R&D, but Europe is still very far from having a coordinated R&D and industrial policy[1].

3.4. Adapting to the change in the industry cost structure: from an OPEX to a CAPEX world

The theory for electricity market liberalisation was developed in the early 1980s in a very different context from today. One important element in the liberalisation dynamic was technology development and innovation. Information technologies allowed the real time exchange of data needed for the coordination of the chain of production, transport and distribution, and the commercialisation of electricity. Whilst electricity production had been characterised for decades by increasing returns to scale, the development of combined cycle gas turbines which were scalable and modular played a key role in allowing new entrants into the generation business.

Competitive power markets are based on the fundamental principles of the peak load pricing theory. Market participants bid their short run marginal costs (SRMC), and fixed cost are recovered through: i) inframarginal rents as technologies with higher SRMC clear the market and set the power price, and ii) scarcity rents when the market is tight and prices go beyond the SRMC of the technology clearing the market.

This market paradigm worked well to induce competition between technologies with significant variable costs, but will likely need to be adapted to reflect the recent changes in the technology costs structure of the generation mix. In the past four years (from 2009 to 2012), more than 60% of the capacity additions (110 GW out of 174 GW) consisted in zero or very low marginal cost technologies, including renewables or nuclear plant. For all low carbon technologies – renewables, nuclear and carbon capture and Storage – investment costs represent a large charge of the total generation costs. Figure 7 shows generation costs estimates for different technologies for Germany, and highlights the weight of investment costs in the total generation costs for low carbon technologies, whilst gas and coal plants generation costs remain dominated by the fuel and operating cost.

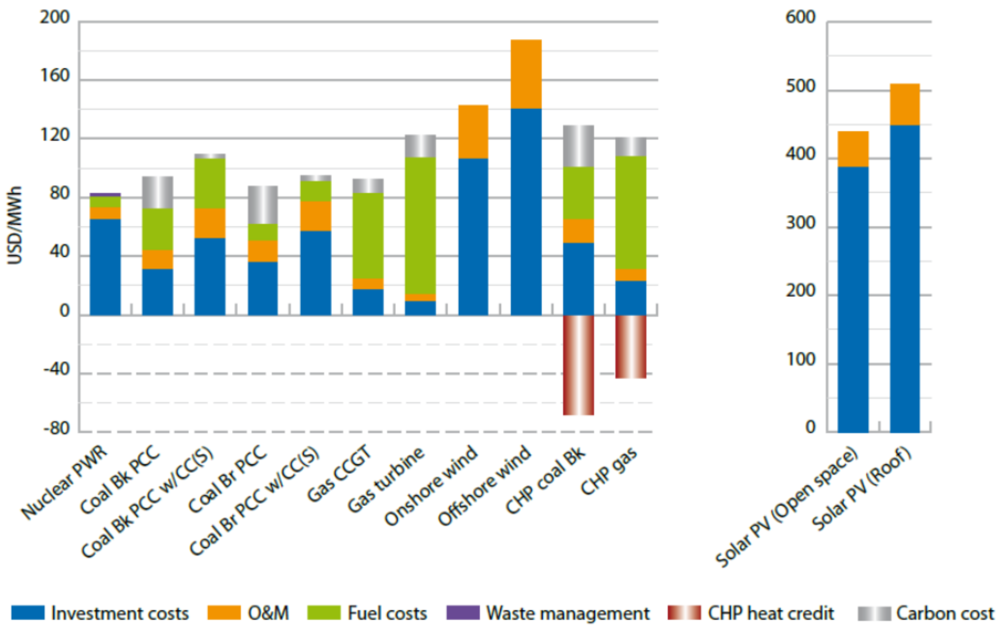
In concrete terms, the European electricity industry is moving from an “OPEX world” into a “CAPEX world”. This has important implications for the evolution of the design of competitive power markets. Whilst in theory marginal cost pricing can still work with

(1) European Commission (2007), Communication “Towards a European Strategic Energy Technology Plan”, COM(2006) 847 final, 10 January.

a part of the generation mix having zero or very low SRMCs, prices will likely become very volatile as the share of renewables increases and technologies with zero SRMC clear the market increasingly frequently. In concrete terms, the risk is that prices would be at or near zero (and could even be negative) for long periods of time, and fixed costs for thermal plants would therefore have to be recouped during few hours, therefore leading to extremely high prices.

The gradual increase of the share of renewables therefore should be supported by reforms of the target model for electricity markets in Europe, reflecting the change of the industry cost structure. This implies that a transition to a market design that complements marginal pricing with some other mechanism to support fixed cost recovery will be needed. Alternative models of competition are possible for industries with a costs structure dominated by fixed costs. The key is to apply competitive pressure where it does matter, primarily on the investment decision. In other industries which are capital intensive, this is done through e.g. the auctioning of long-term contracts[1]. In this respect, experience from Latin America provides alternative models of competitive arrangements, where periodic auctions are run for long-term contracts of both thermal and renewables plants, and could constitute a useful learning case for Europe.

Figure 7 – Generation costs breakdown for selected technologies Germany, 10% WACC



Source: OECD (IEA / NEA) study, Projected Costs of generating electricity, 2010 edition

(1) See e.g. Finon D. and Roques F. (2008), "Financing Arrangements and Industrial Organisation for New Nuclear Build in Electricity Markets", *Competition and Regulation in Network Industries, Intersentia*, 9(3), pp. 247-282, September.

4. Out of market policies to support clean technologies undermine electricity markets functioning

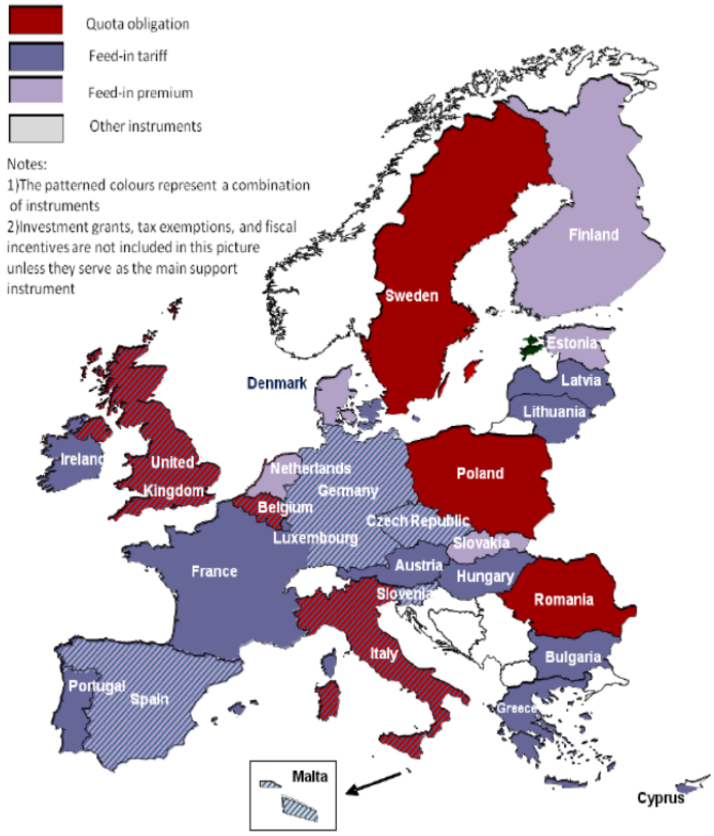
Current electricity markets in Europe are overlaid by a range environmental legislations and regulations which create important distortions in current electricity markets. These environmental regulations include policies supporting the production of renewables electricity sources (RES), the European Emissions Trading Scheme (ETS), as well as emission standards and a range of specific plant operating constraints (e.g. for water cooling intake, water discharge for hydro plants, or specific nuclear regulations).

4.1. A patchwork of approaches which lacks coordination

The current approach toward supporting renewables in Europe shows a wide diversity of approaches. Figure 8 shows the status quo in different countries. Three main support mechanisms can be distinguished with some hybrids:

- *feed-in tariffs* guarantee a fixed price for energy amount fed into the grid. This price is usually higher than the electricity market price and the difference is charged to end users though a pass through mechanism which varies by country;
- *a variant of feed-in tariffs is the feed-in premium scheme*, or a contract for difference (CFD). Under a premium approach, RES producers receive the electricity market price and a fixed premium for producing renewable energy. This feed-in premium scheme may include a cap and-floor limit that guarantees minimum and maximum tariffs independent of the electricity market price thus reducing the overall risk. Under a CFD approach, RES producers receive the difference between the electricity price and a guaranteed level which is taken as reference:
- *a Green certificate scheme* relies on a renewable generation obligations imposed on suppliers, who can either produce (internally or externally) “green electricity” or buy the equivalent in green certificates. Green certificates are produced each time an accredited renewable energy source generates. If suppliers do not fulfill their renewable obligations, they must pay a penalty: the buy-out price.

Figure 8 –Type of renewables support policy by country



Source: Ragwitz et al. (2011)[1]

There is a large academic literature and practitioner's evidence on the pro and cons of the different schemes[2]. Depending on the maturity of the technology, some schemes are more appropriate than others. A concern is that the lack of coordination between the national approaches could lead to suboptimal deployment, with a strong build up in some regions that are not necessarily corresponding to the best endowed in terms of wind or solar resource, thereby increasing system costs for European consumers[3].

Most importantly, these RES support schemes interact in a different way with electricity market dynamics. In that sense, the lack of a coordinated approach across the different countries can lead to distortions on electricity markets. This is particularly

(1) Haas R., Panzer C., Resch G., Ragwitz M. and Reece G. (2011), A. Held. A Historical Review of Promotion Strategies for Electricity from Renewable Energy Sources in EU Countries, Renewable and Sustainable Energy Reviews, 15(2), pp. 1003-1034.
(2) See eg. Hiroux C. and Saguan M. (2010), Large-scale wind power in EU electricity markets: Time for revisiting supports and market designs?, *Energy Policy*, 38(7), July, pp. 3135-3145. Ragwitz M. and Steinhilber S. (2013), Effectiveness and efficiency of support schemes for electricity from renewable energy sources, accepted for publication at WIREs Energy Environment.
(3) See e.g. Roques F., Hiroux C. and Saguan M. (2010), "Optimal wind power deployment in Europe--A portfolio approach", *Energy Policy*, Elsevier, 38(7), July, pp. 3245-3256.

true in regions which have implemented price-coupling, where a contagion effect for the effect of RES on electricity market price dynamics is likely to happen.

4.2. Renewables support policies isolate operators from market dynamics and create distortions

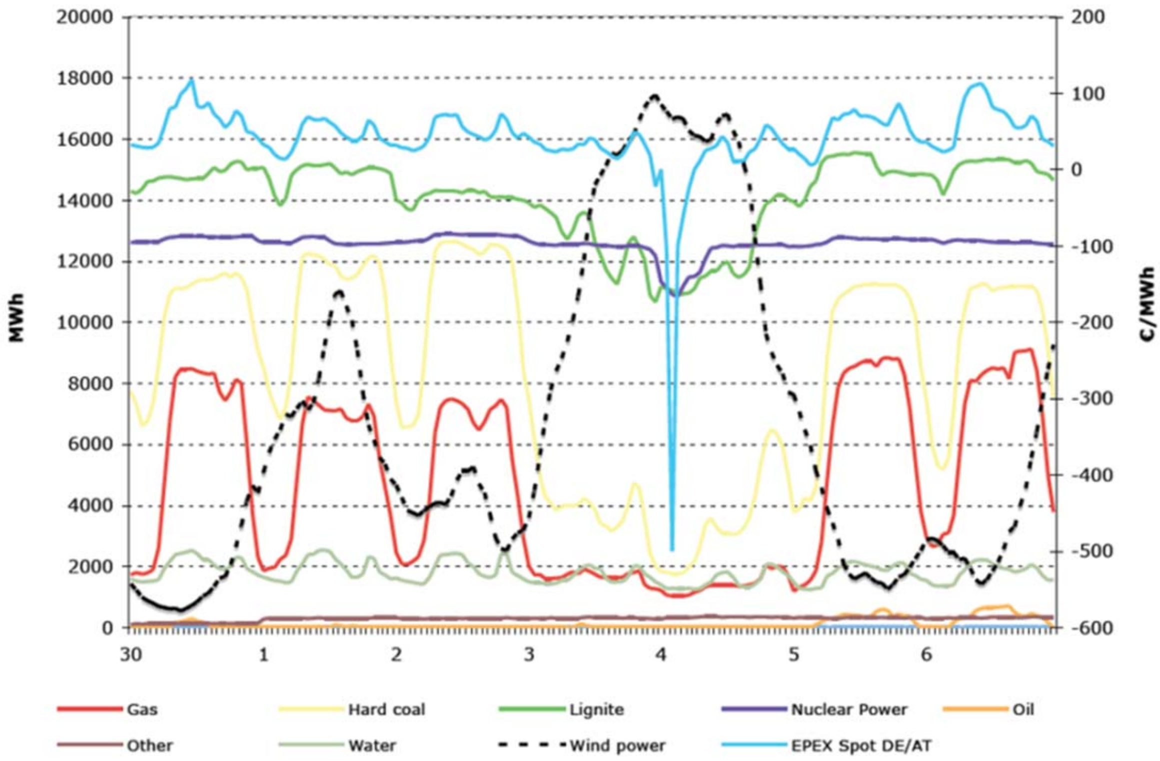
One growing issue with policies supporting RES is that they largely rely on “out of markets” arrangements to remunerate renewables producers, which therefore are immune to the operational or investment incentives conveyed though power prices. For instance, feed in tariffs which guarantee a fixed power price by MWh produced irrespective of the market price do not provide RES operators incentives to produce and sell electricity at times when it is most valuable to the system – e.g. to schedule maintenance at times which would penalise the system the least. As a consequence, the costs of balancing the system fall onto conventional generators.

Most importantly, wind or solar producers under feed in tariffs have incentives to produce even when the system is oversupplied. This leads in some cases to significant distortions in power price dynamics, such as negative power prices. Negative prices have been seen recently in Germany, France, and in Nord Pool in Denmark. Bidding negative prices is rational when fixed costs and opportunity costs imply that a generator will make more – or loose less – money by running than turning the plant off. Plant operating constraints include issues such as the minimum stable load, as well as the minimum down time and startup costs.

For instance in Germany, at times when renewables production is strong and power demand is low, renewables production suffices to meet power demand. The opportunity cost of not producing or stopping for a short time production for some of the least flexible thermal plants (such as e.g. lignite or nuclear plants) means that they are willing to bid negative prices to remain online. Figure 9 shows the reaction of different generation technologies to the negative prices (-500 €/MWh) on 4 October 2009 in the early morning, at 3 am. Wind generation was significant at 17.2 GW, and gas and hard coal power plants almost entirely switched off, as gas capacity online fell from 7 GW to 1 GW, and hard coal fell from 12 GW to 2 GW. However, the least flexible thermal plants – nuclear and lignite – mostly stayed on: nuclear fell from 14 GW to 13 GW, lignite from 13 GW to 11 GW.

Whilst negative prices can be interpreted as a sound economic signal reflecting operational constraints, feed in tariffs for renewables amplify the issue by making RES non responsive to price signals. RES producers have indeed an incentive to bid negative to remain online as long as the prices in the market net the feed in tariff are positive. This can lead to system inefficiencies and increase costs for consumers as the opportunity cost of not producing for a renewables is artificially very high because of the feed in tariff.

Figure 9 – Reaction of different generation technologies in Germany
to negative power prices on October 4, 2009



Source: Vassilopoulos P. (2010) based on EEX Transparency and EPEX Spot data

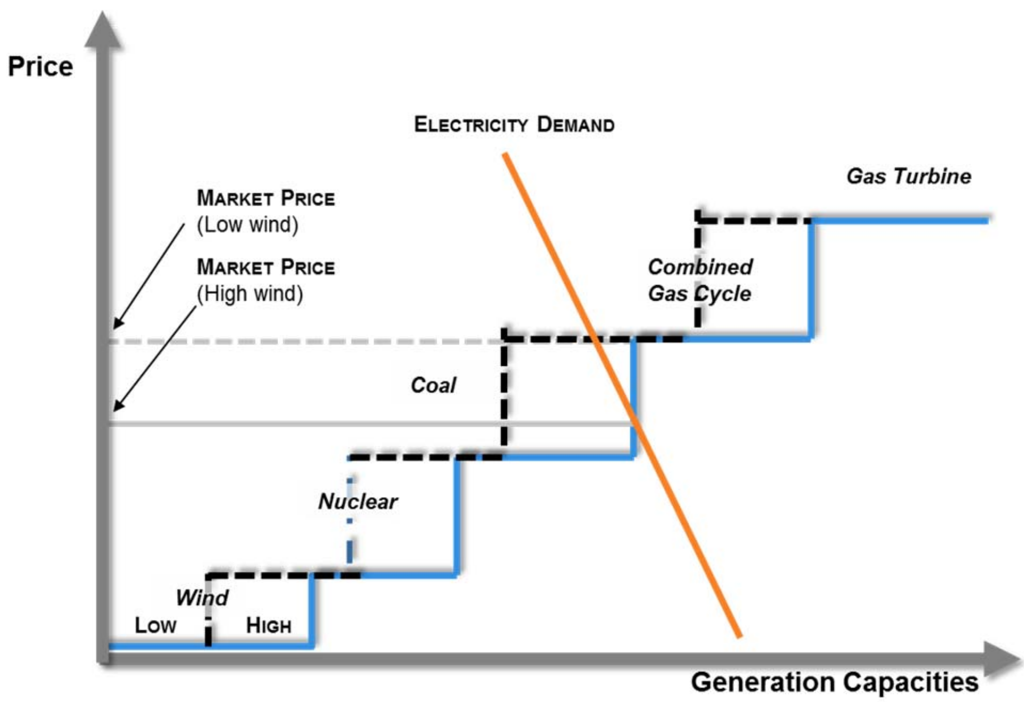
4.3. Renewables displace thermal plants in the merit order and amplify the missing money issue

The other effect of mandating the deployment of renewables onto the European power system is that they displace plants in the merit order, and therefore have a significant effect on power prices dynamics and the revenues of thermal pants. This is known and referred to as the “merit order” effect, by which low marginal cost renewables technologies displace more expensive thermal plants (Figure 10). By modifying the generation mix policy makers change the distribution of revenues to the existing assets, reducing both the running hours of thermal plants and the expected power prices. This leads to different issues in the transition phase as the system adjusts the generation mix to reach a new equilibrium, and in the new equilibrium phase.

The transition phase is the period during which plant operators adjust their operational and investment decisions, and reassess their portfolio of plants with some assets being decommissioned. One important issue in the transition is one of pace of this transformation of the generation mix, and of the associated change in the distribution of revenues. If the transformation is so rapid and/or unpredictable as to radically alter the revenues of some units which are still in the amortisation phase, it can lead to significant stranded costs and destabilise the system. The distributional effects also depend on whether the revenues from the new RES plants are captured by the incumbent players operating the thermal plants which see their revenues reduced, or whether these go to different players.

In the long term, the depressive effect of RES on power prices represents a more structural issue as power prices will be on average lower than in the previous equilibrium, and with growing shares of renewables, will become more volatile. This might lead to an unstable market dynamic when renewables become the marginal technology for significant periods of time, where power prices would oscillate between extremes at short notice and in an unpredictable way. As the share of RES technologies with low variable costs increases, the role of marginal costs pricing as the pillar of electricity markets will have to be revised. This can happen gradually as additional remuneration sources through short term markets and capacity markets gradually provide new sources of revenues reflecting the growing importance of these products to the system.

Figure 10 – The merit order effect of RES



4.4. The European carbon market: a weak and volatile price signal

The ETS was championed by the European Commission in the 2009 green energy legislative package as the centerpiece of European policy toward a decarbonised energy mix[1]. But since the start of Phase 2 in January 2008, prices have been on downward trend, which has triggered a debate about whether the ETS is working properly and about the need for reform. The evidence is growing that the weak and volatile prices in the ETS are not effective in driving carbon emission abatement in the power sector.

ETS prices have been trading below 10 €/tCO_2 for the past couple of years. In comparison the implied switching price between coal and gas fired generation ranges from 40 to 50 €/tCO_2 today, which implies that the current carbon price is way too low to have a material effect on operational decisions from plant operators. In a more long term perspective, current ETS prices are also held to be well below the kind of carbon prices that are needed to make investment in clean technologies competitive. Assuming a 140 €/MWh cost of production for wind offshore and a 210 €/MWh cost of production for solar PV, the implied carbon price that would equalise their long run generation costs with a combined cycle gas turbine (about 70 €/MWh) are respectively 240 €/tCO_2 and 430 €/tCO_2.

The drop in carbon prices over the past few years can be explained by the growing oversupply of allowances for phase 2 and 3. The supply of allowances was fixed in 2007 for Phase 3 up to 2020, and since then a series of shocks affecting the supply and demand of ETS allowances have led to the current oversupply situation. The economic crisis that started in 2008 and the weak economic recovery that followed depressed industrial activity and reduced emissions compared to the expected emissions as defined by the cap for phase 3. On the supply side, a rush to register international offset projects and use the resulting credits ahead of quality controls that went into effect in 2013 also displaced ETS allowances demand and contributed to increasing the supply surplus.

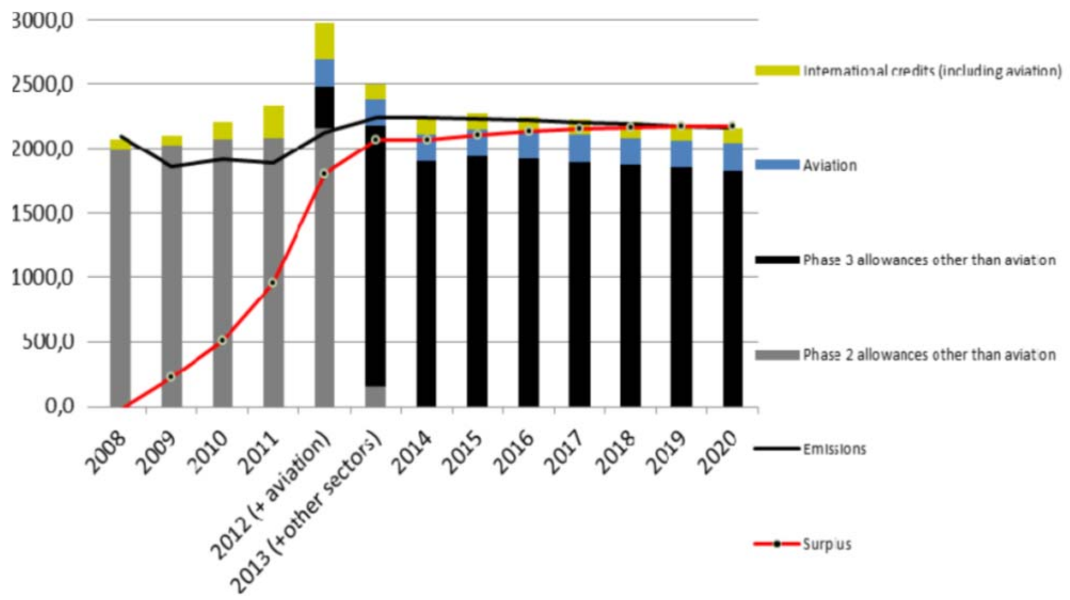
As Figure 11 shows, the ETS is now oversupplied well into phase 3, and the current low prices reflect the longer-term prospects for a shortage in Phase 4, covering 2021–2030, as well as the likelihood of a policy intervention to support prices into Phase 3. Indeed, the European Commission initiated in 2012 a debate on a two-step approach to a reform of the ETS. The first step would see in 2013 a one-off intervention to tighten the market and boost prices in the near term through the backloading of some 900 mt of CO_2 allowances in phase 3, whilst a review of options for a more structural reform of the ETS should lead in the medium term to a revision of the ETS functioning for phase 4 and beyond. Whilst the short term ad hoc market intervention might be a necessary bad to prevent prices from collapsing and undermining the credibility of the

(1) The European carbon Trading Scheme (ETS) currently covers close to half of the European Union's emissions of carbon dioxide (CO_2).

ETS, it does create a dangerous precedent. If policy makers intervene on an ad hoc basis to tighten the ETS market when prices are judged too low, aren't they likely to intervene again in the future if prices are judged too high? Such interventions would further undermine the credibility of the ETS and of the policy commitments that underpin this market.

The decisive step for the future credibility of the ETS is therefore the more structural reform that the EC has started discussing. A central part of this issue is the overlap of the ETS with national policies in support of low carbon technologies and energy efficiency which have a significant effect on the demand for ETS allowances. In concrete terms, the issue is that the ETS has become a "residual market" for carbon abatement in the power sector. Policies in support of renewables or nuclear have been the prime drivers of power sector investments over the past decade in Europe.

Figure 11 – ETS supply demand balance (2008-2020)[1]



Source: European Commission, State of the European Carbon market

5. Successes and issues with European electricity markets integration

Twenty years after the start of liberalisation, first in the UK and in the Nordic countries, and then in the rest of Europe, the evidence is mixed regarding the achievements of liberalised power markets.

(1) European Commission (2012), "The state of the European carbon market in 2012", COM(2012) 652 final, 14 November.

The three Directives in December 1996, June 2003 and July 2009 represent the key milestones for the coordination and integration of electricity between Member States, and represent a steady progress toward integration of European power markets. Despite all the criticisms, it is important to highlight all the successes to date. The lights have stayed on, and many of the barriers to exchanging electricity between the different European markets have gradually reduced. The sharing of resources cross border has significantly contributed to keeping security of supply, but also to reduce the total system costs for European consumers.

However, concerns remain that in many countries progress toward competitive and integrated electricity markets has been slowed by political opposition, and that most markets remain fairly concentrated. Much of the findings of the European Commission Sector Inquiry into competition in gas and electricity markets published in January 2007 remain valid today[1].

5.1. Some bright spots: Regional initiatives and market coupling

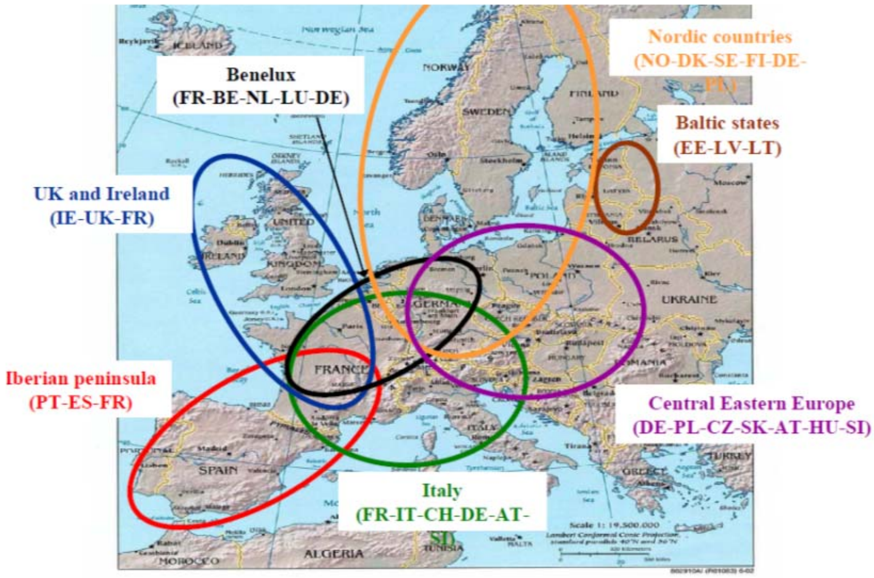
The Third Energy package adopted in July 2009 marked a significant change in approach, in that it takes a more pro-active role in creating harmonised rules for the Internal Market in Electricity. The package, among other things, dealt with unbundling of transmission networks and generation, established National Regulatory Authorities in each Member State and implemented an Agency for the Cooperation of Energy Regulators (ACER), as well as the European Network of Transmission System Operators in Electricity (ENTSO-E).

ENTSO-E is tasked to define legally binding network codes, in accordance with the framework guidelines defined by ACER, focusing on a number of critical issues for market integration, including third-party access rules, capacity allocation and congestion management rules, system balancing, and rules regarding harmonised transmission tariff structures, including locational signals and inter-TSO compensation schemes. In practice, the work on the framework guidelines and network codes is part of the implementation of the so-called “Target Model” which aims to coordinate the operation of the integrated European electricity market.

(1) The Sector Inquiry identified the following issues:
- “too much market concentration in most national markets;
- a lack of liquidity, preventing successful new entry;
- too little integration between Member States’ markets;
- an absence of transparently available market information, leading to distrust in the pricing mechanisms;
- an inadequate current level of unbundling between network and supply interests which has negative repercussions on market functioning and investment incentives;
- customers being tied to suppliers through long-term downstream contracts;
- current balancing markets and small balancing zones which favour incumbents.”

In parallel, a more bottom-up market integration process is at work through the creation of the Regional Initiatives (RIs) and other, independent regional integration projects (such as the Trilateral Market Coupling). Figure 12 describes the 7 key regional initiatives.

Figure 12 – The Seven Regional Initiatives



Source: Everis and Mercados (2010)[1]

These work streams have led to a number of successes in regional market integration. In particular, the implementation of market coupling on a regional basis has allowed some efficiency gains in the use of interconnections, and led to stronger price convergence between couples markets[2]. In 2006 the existing national Day Ahead markets of France, the Netherlands, and Belgium were coupled by a price coupling mechanism. On 9 November 9, 2010, the Central Western European Market Coupling was implemented by adding Germany and Luxembourg, which led to a strong increase in the price convergence between the different countries.

The progress with the implementation of the Target Model, and in particular some of the Framework Guidelines and Network codes, is facing a number of hurdles. The stated European Commission ambition to have an integrated European electricity market with price coupling across all main markets by 2015 will likely be delayed, as

(1) From Regional Markets to a Single European Market, Everis and Mercados (2010).
(2) Market coupling in wholesale power markets uses implicit auctions in which players do not receive allocations of cross-border capacity themselves but bid for energy on their exchange. The exchanges then use the Available Transmission Capacity (ATC) to minimise the price differences between two or more areas. In so doing, market coupling optimises the interconnection capacity and maximises social welfare. This process increases price convergence between market areas, eliminates counter-flows. Price differentials send a price signal for investments in cross-border transmission capacities.

differences between national electricity market designs make the coordination and definition of common rules a challenge. But despite these issues, the development of network codes does represent an important milestone and a significant step forward in European markets integration.

5.2. Infrastructure development is lagging behind

The ambition to build an integrated pan European electricity market has seen relatively slow progress to date as critical infrastructures faced repeated delays. This comes as a stark contrast to the ambition of the European Commission to step up the rhythm of interconnection build up as a critical facilitator of an affordable transition toward a low carbon electricity system. ENSTO-E 10 2012 Investment Plan calls indeed for two- to threefold increase in the rate of infrastructure investment, and anticipates €104 bn of investments in power grid infrastructure over 2012-2022.

There would clearly be large benefits in having a more interconnected market, as this would help to alleviate some of the local network balancing constraints, and would allow optimizing the use of different generation and demand sources over a wider geographic area. More interconnection capacity could also allow tapping into the hydro reserves in the Nordics and in the Alps for the storage and balancing of electricity on a wider scale than just their immediate regional surroundings. Similarly, an offshore wind grid in the North Sea would allow harnessing the good wind resources of the area whilst integrating better the Nordic grid with the CWE and UK power systems. Finally, some areas on the periphery of Europe remain weakly connected to the European grid – for instance the Baltics or Balkan countries are relatively isolated and would largely benefit from more interconnection with the rest of the European grid.

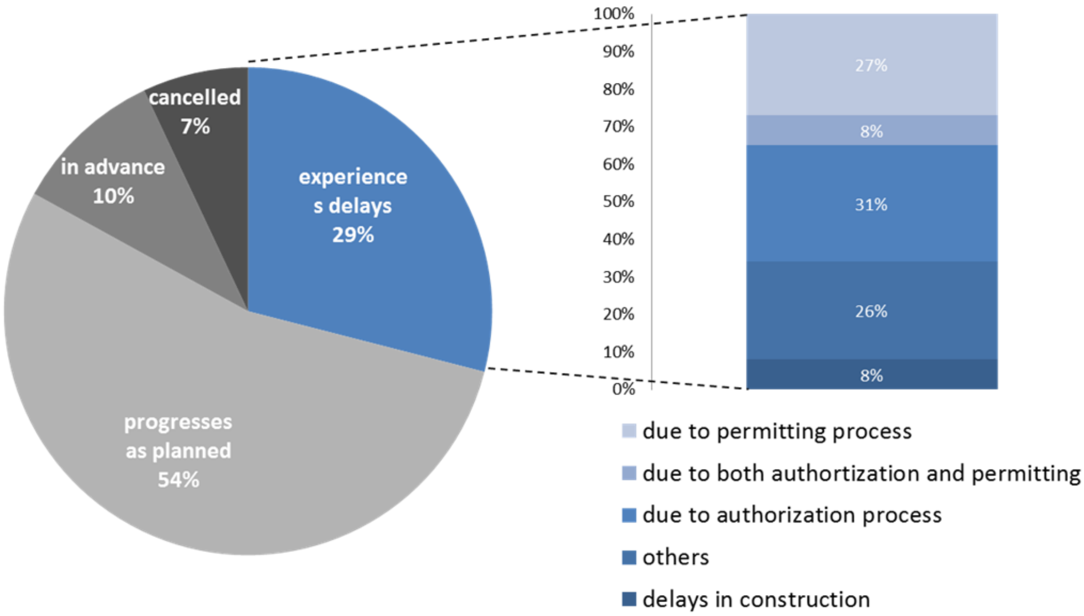
The European Commission has brought forward various initiatives to fasten the deployment of critical infrastructures. Plans for the Trans-European Energy Networks for Electricity (TEN-E) and policies like the Priority Interconnection Plan (PIP) aim to promote their construction[1]. The 2012 Ten Year Network Development Plan (TYNDP) of the European Network of Transmission System Operators for Electricity (ENTSO-E), published in July 2012, calls for 58 GW of new interconnection capacity in Europe by 2022. This would represent a tripling of the historical rate of additions in the last decade.

However, in practice progress has been slow and the pace of development of both internal and cross order transmission lines is significantly slower than anticipated. For instance, the French-Spanish interconnection extension across the Pyrenees, or the Austrian "Steiermarkleitung" projects have faced up to a 25 years of delays. The

(1) Source: TEN-E: http://ec.europa.eu/energy/infrastructure/tent_e/ten_e_en.htm;
PIP: http://europa.eu/legislation_summaries/energy/internal_energy_market/l27081_en.htm.

progress of most projects has been slowed down by a range of factors: primarily local opposition, but political and regulatory barriers also played a role in some cases. In the past couple of years, about one third of the ENTSO-E "Projects of Pan-European Significance" have experienced delays, and five have been entirely cancelled (Figure 13). Most often the cause of the delays resides in authorisation and permitting process, as the coordination of different parties across borders is usually complex, and local opposition typically also represent a key hurdle for such infrastructure projects.

Figure 13 – Evolution in the timing of interconnection completions, and causes of delay or cancellations (ENTSO-E TYNDP of 2010 vs. 2012)



Source: ENTSO-E ten year network development plans, 2012 and 2010

5.3. A missed opportunity: quantifying the benefits of further integration

The gains in terms of power price convergence stemming from a theoretical copper plate in Europe, i.e. assuming there would be no transmission constraints anymore, are potentially significant on average. The gains would be larger on average for countries and regions on the periphery, which are relatively isolated, such as the UK, and Italy. On the other hand, in regions which are already well interconnected such as CWE, market coupling has already driven significant price convergence. The remaining small price differentials are insufficient to make most new interconnection economical based on pure price arbitrage.

Booz & Company estimated that the benefits of the integration due to market coupling, once market coupling is fully implemented across the EU, will be of the order of €2.5bn to €4bn per year, or about €5 to €8 per capita per year. About 58%-66% of this benefit has already been achieved due to the level of market coupling already present, especially in the large electricity markets of NW Europe and the Nordic region. The remaining 34%-42% will be achieved with the completion of the Target Electricity Model[1].

Moreover, the benefits of greater interconnection can be significant in some special circumstances. For instance, power prices in the Nordics can increase significantly in a dry year when the hydro reservoirs levels are low; similarly, power prices on the continent are sensitive in France to peak load variations in case of a cold spell because of the large share of electric heating, whilst prices in Germany will vary according to renewables production. As a consequence, new interconnection can be seen as insurance mechanisms against potential disruptions or events causing sudden price increases. This is reflected in the latest ENTOS-E 10 year plan, which identifies security of supply benefits integration as the key drivers of new interconnection lines in Europe.

Market coupling and power price convergence are delivering only the benefits of short term arbitrage in energy trading. Booz & Company modeled the potential gains by 2030 of a fully integrated market would facilitate the short and long term trading of energy, renewables, balancing services and security of supply without regard to political boundaries. They found gains from integrating the energy markets that could reach 12.5 to 40 bn€/year in 2030, or about 25 to 80 € savings per capita / year. In addition, the gains from coordinating renewables investments by locating plants where most efficient could amount to 15.5 to 30 bn€/year in 2030, or about 31 to 60 € savings per capita / year.

6. Incomplete electricity markets and the missing price signals

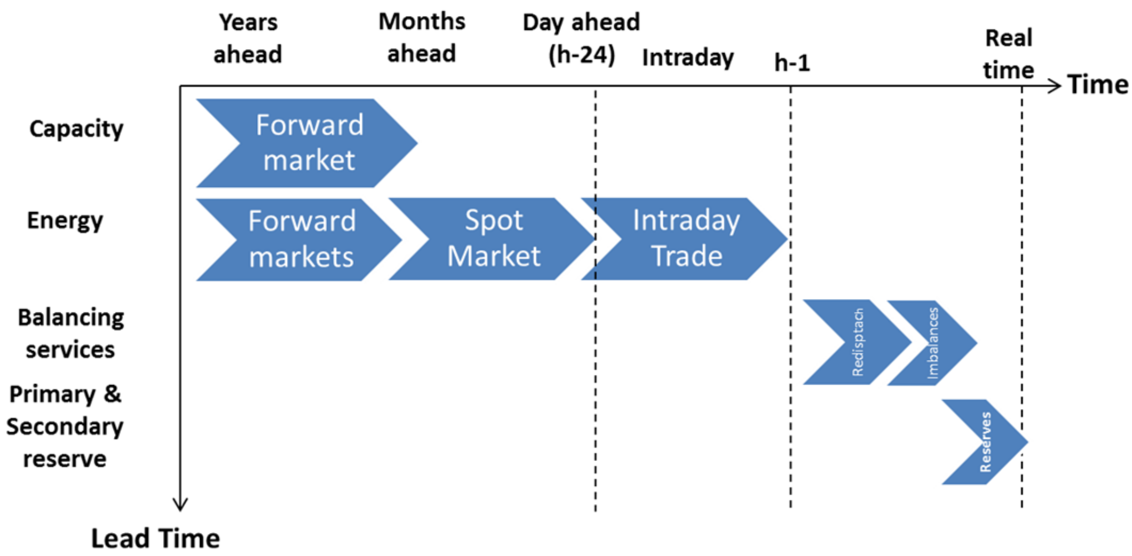
The initial design of electricity markets focused on implementing the textbook model of competitive day ahead power markets accompanied by intraday balancing under the control of the system operator[2]. Different countries followed different routes, with the center of Europe going for mandatory pool type centralised arrangements (Spain, Italy, the Nordics, Ireland, the UK initially), whilst the rest of Europe did go for decentralised voluntary markets relying on voluntary bilateral trading.

Whilst the focus has historically been on day ahead power markets, price signals from day ahead markets alone are insufficient to provide the right operational and investment incentives to market participants. Electricity is a special good and academics and practitioners alike have now realised that a sequence of decisions

(1) Booz & Company (2013), Benefits of an integrated European energy market. Prepared for: European Commission Directorate-General – Energy, 20 July.
(2) See for instance Joskow P.L. and Schmalensee R. (1983), *Markets for Power: An Analysis of Electric Utility Deregulation*, Cambridge. MIT Press.

associated with the value of electricity does stretch from the very short term balancing of the system in real time – as power cannot be stored economically on a large scale – and the very long term for investments in production technologies that typically have a 20 to 60 years time horizon. Figure 14 illustrates the different time frames for capacity, energy, balancing services, and primary and secondary reserve, from several years in advance to real time.

Figure 14 – The sequence of electricity markets



In fact, the evidence is growing that price signals are missing both on a very short time frame – within day or within the last hour before actual production – and on a long time frame to trigger investments when the system is tight. Similarly, transmission constraints mean that power produced or sold in different parts of a constrained network has a different value.

In economic terms, electricity is not a uniform good insofar as it has a timing dimension – electricity produced or consumed at different times has a different value – and locational dimension – electricity produced or consumed in different locations has a different value depending on the system constraints. In theory, a series of markets from forward markets to the real time would be needed to put a price or value on the different attributes of electricity production or consumption depending on time and location.

Whilst such a complex sequence of intertwined markets might be too complex and impractical in practice, the current framework is overly reliant on price signals derived from day head markets on a national or region wide basis. There are “missing markets” to value the different type of electricity products – ranging from the short term to the long term investment incentives, as well as the locational value of electricity. The next three sections focus in turn on these critically missing price signals under different time frames.

6.1. The lack of price signals to reward short term operating flexibility

The recent development of intermittent renewables reinforces the need to reward operational flexibility as well as dependability on short time frames, both for flexible power plants and demand side response. The value of short term operating flexibility is typically captured through intraday and ancillary services, and there are growing concerns that such short term prices signals do not convey the proper scarcity value of operating flexibility in many countries, calling for revisiting the current arrangements for intraday trading and ancillary service procurement.

Intraday exchanges remain limited in many Member States. The current approaches for intraday trading vary greatly by country, with differences in organisation (continuous versus auction based intraday trading) as well as market liquidity across European markets. After “gate closure”, typically one hour before real time, the system operator centralises trades on the system and runs a balancing mechanism, and procures shorter term products such as the 1st, 2nd and tertiary operating reserves.

The concern with the current arrangements for balancing and reserve procurement in many countries is that short term balancing products which have a critical and growing value for the system stability are not always procured by system operators on a competitive basis. Whilst there are very different approaches across Europe, in some countries the procurement of these products remains based on long term contracts and the lack contestability – and/or the poor liquidity of such products makes it difficult to reflect the fast evolving value of these short term balancing services to the system[1].

Several countries are exploring ways to improve their balancing mechanisms. The UK is for instance considering whether it should coming back to one single imbalance price, based on marginal pricing rather than average pricing of the different bids in order to better reflect the evolving value of balancing depending on the system net or short situation. Work is also in progress at the European level though the Framework guideline on balancing to harmonise approaches and encourage cross-border exchanges of balancing energy.

(1) See Mott MacDonald and Sweco (2013), Impact Assessment on European Electricity Balancing Market - Final Report, March 2013, Contract EC DG ENER/B2/524/2011.

6.2. Inadequate price signals for investment incentives

Concerns are growing that current electricity market arrangements do not provide adequate investment incentives. Most power markets in Europe are "energy only" markets, insofar as there is no specific mechanism to put a value on capacity to produce when the system becomes tight (to the exception of Spain, Portugal, Italy and Greece and Ireland which have some form of capacity payment). This is based on the assumption that electricity prices will rise if market players anticipate an impending shortage of capacity, leading to new investments.

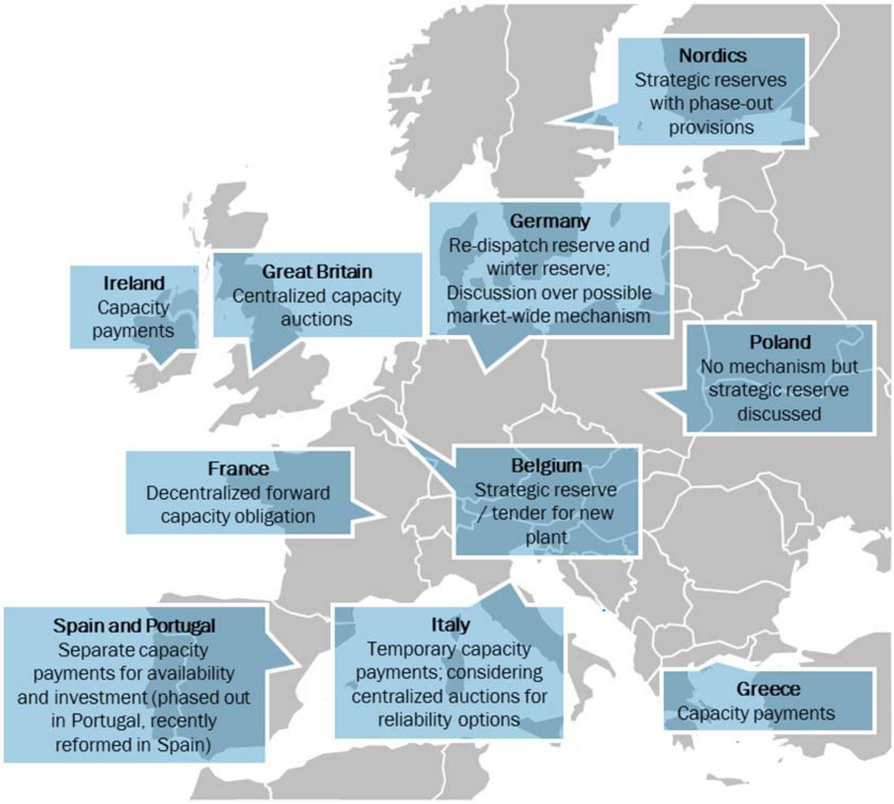
This is grounded theoretically in the "Peak Load Pricing Theory", whereby marginal pricing can provide fixed cost recovery of investment based on the scarcity rents that all power producers earn when the system is tight. The assumption underlying the current market design based on energy only markets is that power prices could climb to the "Value of Lost Load (VOLL)" at times of scarcity and that this would naturally lead market players to benefit from periods of high prices to remunerate their fixed costs.

However, the evidence is growing that for a variety of reasons – ranging from operational price caps to the political unacceptability of very high power prices – that power prices are not allowed in practice to reach the VOLL, leading to a chronic shortage of revenue for plant operators, the so called "missing money" issue as referred to in the academic literature[1]. A range of administrative procedures as well as market distortions such as price caps cause this rigidity of power prices, leading to the missing money.

The key issue, however, is that in the absence of active demand side participation for load that is not metered in real time, market participants have no way to express their value for power at different times. This calls into question the rationale to rely on market forces to determine the adequate level of installed capacity to guarantee security of supply. Various other market imperfections have also been mentioned in the academic literature, ranging from market participants short sightedness, risk aversion or the difficulty to hedge or transfer risks on a long term basis, to argue for separate arrangements to be put in place to guarantee security of supply[2].

(1) See for instance Finon D. and V. Pignon (2008), "Electricity and Long-Term Capacity Adequacy, The Quest for Regulatory Mechanism Compatible with Electricity Market", *Utilities Policy*, 16(3), September, pp. 143-158.
(2) See eg De Vries L.J. (2007), Generation adequacy: helping the market do its job, *Utilities Policy*, 15(1), pp. 20-35. Or Roques F. (2008), Market design for generation adequacy: Healing causes rather than symptoms, *Utilities Policy*, 16(3), pp. 171-183.

Figure 15 – Map of capacity mechanisms in Europe



Perhaps more importantly, a number of recent market reforms to put in place supplementary arrangements demonstrate that security of electricity supply is considered by most governments as so critical to the economy that it should be guaranteed through a specific mechanism. The current debate on the introduction of "capacity mechanism" is grounded in the fundamental issue that current energy only electricity markets do not provide adequate long term investment incentives, and cannot guarantee that there will be sufficient spare capacity for the lights to stay on. More precisely, most governments have an explicit or implicit target for the number of hours of load shedding that they think consumers are happy to accept (such as 3 hours per year on average in France, 20 hours in Belgium, etc.), and current power markets are lacking an economic mechanism to guarantee that investments will be forthcoming in accordance to this policy determined reliability target.

The ongoing debate on capacity mechanisms throughout Europe revolves around the design of the supplementary arrangements to guarantee security of supply (Figure 15). Whilst there is a range of approaches, a key difference revolves around the competitive or regulated nature of the mechanism, namely whether it is a regulated approach or a market based mechanism that determines the price of capacity. The concerns are also mounting that such mechanisms, which are largely implemented on a national basis, could undermine further integration of European power markets. Indeed, the current patchwork of approaches indicated the merits of working toward if not harmonised, at least coordinated approaches on a regional basis.

6.3. Price signals do not provide adequate locational incentives

Electricity is a special good in the sense that production and consumption need to balance in real time in each point of the network. It is therefore important that electricity prices convey locational signals to optimise the operation of networks, production and load in different nodes of the network, but also to provide incentives to locate new production assets, build new transmission lines, or to implement demand side management programs, in the most efficient way, i.e. in the way that maximises social welfare.

Congestion management of networks is important to manage transmission constraints that may limit the flow of electricity from generators to loads in some circumstances and cause problems related to operational security (such as overloading of network elements). There are two main alternative theoretical designs[1]:

- the zonal approach defines limited geographical areas (zones) within which trading between generators and loads is unlimited. However, to cope with operational security constraints of the network, trading between these areas is limited by transmission capacity based on capacity calculation and allocation process. In practice a zone is characterised by one single price for the whole zone, and the cost of congestion management is in part pushed to the frontier with the neighboring price zone.
- the nodal design considers all trades between generators and loads as equal in terms of using the infrastructure. The bid price and quantity of each generator and load is weighed against its influence on the physical network, leading to different prices at each node of the network.

In practice, the current electricity markets arrangements are largely based on a zonal approach, which divides the market into different price zones. Whilst historical legacy means that current zones do largely correspond to countries, there are no theoretical reasons to consider these current zones as being optimal and providing the right kind of location signals for both operations and/ or investment. Smaller price zones have already been implemented in some places with significant transmission constraints, such as the Nordic countries (with market splitting) or Italy (which has different price zones).

The growth of intermittent renewables in some countries in previous years has raised questions on whether the current price zones are optimal. For instance, loop flows between the north of Germany where a lot of wind generation is located, and the South of Germany, where there is a deficit of electricity since the decision to shut down some nuclear plants, have created some tensions between Germany and neighboring countries. These tensions have culminated with the threat to implement or actual implementation of phase shifters on the border to control better the flows between Germany and its neighbors, so that the costs of balancing wind intermittency

(1) See ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2011 - 29 November 2012.

are born by Germany through internal re-dispatch rather than by exporting the surpluses to its neighbors' grids.

Investment incentives to locate plants or to encourage DSM in specific locations are largely shaped by the type of network and connection charges. The two extreme approaches are deep or shallow connection charges. Shallow costs refer to the equipment needed to connect a generation plant to the nearest point of the network, whilst deep costs include shallow costs plus the costs of reinforcing the network necessary to connect that plant. The different Member States have very different approaches to connecting regimes, and some countries allow renewables plant to benefit from more favorable connections charges than those applying to conventional generators.

These differences both in congestion management and in connection charges highlight the lack of coordinated approach toward sending appropriate locational signals to electricity market players in Europe. This could increase the total electricity system costs, and create tensions between different stakeholders. The issue is likely to grow as more renewables plants are connected to the European grid, as these plants are often located far from the areas with important load – making it urgent to define a coordinated approach[1].

Conclusion
Directions for reform and for a sustainable electricity market design

Despite some steady progress toward integration, European electricity markets are currently at a crossroad. The key issue is not so much the imperfect or incomplete process of liberalisation and integration of electricity markets, but rather the need to reconcile this process with the new policy priorities in favor of decarbonisation and competitiveness.

Europe's target model for electricity market integration has indeed become obsolete before it is even implemented, as it failed to take into account the implications of the changes in context over the past decade. Confronted with the deficiencies of the European model, different countries have embarked in the past few years into national reforms which create additional distortions through e.g. the implementation of special mechanisms to guarantee security of supply (such as capacity mechanisms) or to support the carbon market (such as a carbon price floor).

As this report has showed, European electricity markets suffer from two types of issues which are interconnected:

(1) ACER has recently launched a consultation on revisiting current bidding zones, see: www.acer.europa.eu/Official_documents/Public_consultations/Pages/PC_2013_E_04.aspx

- The “extrinsic” issues have to do with the lack of consistency of Europe’s energy policy framework, and the failure to take into account the impact of the decarbonisation and competitiveness on the target design of electricity markets. These include the design of the renewables support policies, the issues with the European Trading Scheme, as well as the need for faster and more coordinated deployment of critical infrastructures such as interconnection capacity.
- In addition, a range of “intrinsic” issues with the current design of electricity markets prevent them from sending the appropriate price signals for investors. Electricity is a multidimensional good, as its value depends on when and where it is delivered. Many of the issues in current electricity market stem from the focus on the day-ahead markets as they key vehicle toward integration, whilst it is only one element in the chain of power markets. Price signals are missing in the short term to value the operational flexibility of plants and demand response which provides critical value to balance the electricity system in real time. Price signals are also missing to support long term investments and guarantee the resource adequacy of the system.

The result is a market and regulatory framework which hamper investments and will not deliver on the stated objectives of decarbonisation and competitiveness of the European economy. A better design and integrated electricity market could deliver large benefits for European citizens. Most importantly, by delaying action, Europe risks locking on an inefficient pathway, which will result in increasing power prices and will likely ultimately undermine public support for decarbonisation.

The solutions to Europe’s electricity market issues can be classified in two broad categories which mirror the diagnostic.

First order priorities include the need to reconcile the design of the target model for electricity market liberalisation and integration with the change in context. The trade offs between the liberalisation of Europe’s electricity markets on the one hand side, and on the other hand the environmental policies in support of decarbonisation as well as the competitiveness and security of supply imperatives, need to be analyzed. The lack of consistency in the different policy packages is the root cause of the regulatory and policy uncertainty that hampers investment. Addressing some of the contradictions embedded into these policies will raise important issues, such as:

- Why has the development of critical cross border infrastructure been so slow, and what are realistic plans for the buildup for Europe’s transmission grid?
- Do all the new lines planned make economic sense, and what are the tradeoffs between the expansion of the grid and further development of generation and demand response resources?
- What is the sustainable pace of deployment of low carbon technologies given their impact on electricity prices and on Europe’s competitiveness? More generally, what is the least cost pathway toward decarbonisation?

- Why is Europe's innovation and R&D support for clean technologies so weak in comparison to the amount of money spent on deploying existing technologies?
- How can renewables and other low carbon policies be reformed to integrate renewables into power markets and subject them to the same incentives as other types of production?
- What is a politically acceptable carbon price in the absence of international commitment to fight climate change and is this compatible with the ambition to make the European Emission Trading Scheme the prime driver of decarbonisation?
- Why is demand response so little developed and how can it be enabled as a critical component of a well-functioning electricity market?

In parallel, second order issues regarding the "intrinsic" incomplete design of the electricity market target model will need to be fixed. It is critical to complete the sequence of electricity markets with the missing elements in both the short term and in the long term. With the growth of intermittent renewables, the short term balancing of the system will rely critically on the implementation of liquid and integrated intraday, balancing and reserve markets. In addition, the implementation of capacity mechanisms in a coordinated way seems necessary to guarantee resource adequacy and security of supply in the long term. The design of electricity markets will also need to evolve to provide better locational signals so that production or demand response are located in nodes of the network where they are most needed.

Beyond these well these short-term reforms of the European target model, a discussion needs to be initiated on the medium to long term model for electricity markets. Indeed, the evolution of the generation mix toward capital intensive technologies, combined with the intermittent nature of some renewables technologies, imply that electricity markets rooted in the principle of short term marginal cost pricing will likely not be appropriate in the medium to long term.

Some exploratory work needs to be launched to study alternative models for the long term (post-2025). These alternative models will likely comprise a greater role for long term contracts to facilitate investment and financing of low carbon as well as thermal technologies. Long-term contracts can be tendered to maintain competition and concentrate it on the investment decision, which is the most important cost factor for capital intensive technologies. A system of auctions for long term capacity contracts could supplement a liquid spot market which role would be confined to the short term dispatch optimisation. In other words, a greater role for auctions of long term capacity contracts could ensure that there is competition "for the market" and a level playing field between low carbon and thermal plants, whilst the spot and intraday markets would ensure competition "in the market"[1].

(1) For more discussion of these issues, see e.g. Finon D. and Roques F. (2013, European Electricity Market Reforms: The "Visible Hand" of Public Coordination, *Economics of Energy & Environmental Policy*, 2(2). Available at: www.ceem-dauphine.org/assets/wp/pdf/Finon_Roques_Visible_Hand1.pdf.

Executive Summary

The European electricity industry is going through a profound crisis as several factors combine to create a challenging operating environment for thermal plants. The key issue is that the regulatory and market framework create a climate of deep policy and regulatory uncertainty which will hamper investments and will not deliver on the long term objectives of decarbonisation and competitiveness of the European economy. This report analyses both the short and long term challenges for the European electricity markets, and highlights some directions for reform.

Setting the scene – context and need for a rethink of the market and regulatory framework

In the short term, the electricity industry faces the challenge of rebalancing largely oversupplied power markets. Policies to support renewables production displace generation from thermal sources, which combined with the effect of the economic crisis on power demand have dramatically reduced load factors for thermal plants. In addition, power prices have fallen to levels which do not reflect the complete generation costs – reflecting a temporary oversupply, but also reflecting the downward pressure on prices associated with the development of renewables. The key issue is that the current market and regulatory arrangements will not lead to an orderly and cost effective rebalancing and could eventually lead to large plant retirements and threaten security of supply.

In the longer term, the ambition to decarbonise the European power sector by 2050 calls for large investments, which clashes with the widespread perception that the power sector is not "investment grade". Europe will need to invest between 40 and 60 billion Euros per year in power generation until 2050. However, the profitability of the electricity sector has fallen dramatically in recent years. In addition, the main traditional investors in the electricity sector – European utilities – are in a weak financial situation, as the total net debt position of the 10 largest European utilities has nearly doubled over the past 5 years to reach about 280 billion Euros.

A rethink of the market and regulatory framework is therefore needed to reduce risks for historical investors, but also to attract different sources of investors such as funds with a long term investment time horizon (sovereign wealth funds or pension funds). **European electricity markets suffer from two types of issues which are interconnected. The *"extrinsic" issues*** have to do with the lack of consistency of Europe's energy policy framework, which undermines the functioning of European electricity markets. In addition, a range of ***"intrinsic" issues*** with the current design of electricity markets prevent them from sending the appropriate price signals for investors.

A better design and integrated electricity market could deliver large benefits for European citizens. Booz & Company estimated that the benefits of the integration due to market coupling, once market coupling is fully implemented across the EU, will be of the order of €2.5bn to €4bn per year, or about €5 to €8 per capita per year. Most importantly, by delaying action, Europe risks locking on an inefficient pathway, which will result in increasing power prices and will likely ultimately, undermine public support for decarbonisation.

First order issues: inconsistencies in European energy policy and interferences with electricity markets

The first order *"extrinsic issues"* have to do with the need to reconcile the electricity market liberalisation and integration process with the new policy priorities in favor of decarbonisation and competitiveness. The recent developments in the global energy markets create a very different context than when the 2008 Third Energy Package and Green Package were passed. The discovery and production of large quantities of shale hydrocarbons in the US has changed the global energy market dynamics. In parallel, the lack of progress at the UNFCCC negotiations have demonstrated the challenge of setting up a globally binding agreement on climate change, casting doubts about Europe's strategy to lead the way. This combined with the economic crisis has led many governments to question the affordability of the energy transition toward a low carbon electricity system.

In practice, current electricity markets in Europe are overlaid by a range of environmental legislations and regulations which can create distortions in electricity markets – e.g. policies supporting the production of renewables electricity sources (RES), or the European Emissions Trading Scheme (ETS). A concern is that the lack of coordination between the national approaches could lead to suboptimal deployment, with a strong build up in some regions that are not necessarily corresponding to the best endowed in terms of wind or solar resource, thereby increasing system costs for European consumers.

One growing issue with **policies supporting RES is that they largely rely on "out of markets" arrangements to remunerate renewables producers**, which therefore are immune to the operational or investment incentives conveyed though power prices. As a consequence, the costs of balancing the system fall onto conventional generators. Wind or solar producers under feed in tariffs have incentives to produce even when the system is oversupplied. This leads in some cases to significant distortions in power price dynamics, such as negative power prices.

In the long term, the depressive effect of RES on power prices represents a more structural issue as power prices will be on average lower than in the previous equilibrium, and with growing shares of renewables, will become more volatile. This might lead to a vicious circle as renewables depress power prices and therefore create the necessity to continue supporting renewables to reach the targets. As the share of RES technologies with low variable costs increases, the role of marginal costs pricing as the pillar of electricity markets will therefore have to be revised.

The ETS was championed by the European Commission as the centerpiece of European policy toward a decarbonised energy mix, but is has become a "residual market" for carbon abatement in the power sector as policies in support of renewables or nuclear have been the prime drivers of power sector investments over the past decade in Europe. ETS prices have been trading below 10 €/tCO_2 for the past couple of years, well below the implied switching price between coal and gas fired generation (about 40 €/tCO_2), and an order of magnitude lower than the kind of carbon prices that are needed to make investment in clean technologies competitive. Going forward a strong ETS with a significant carbon price will be a decisive element to support power prices and close the gap with the costs of renewables technologies.

Second order issues: incomplete electricity markets and the missing price signals

The *"second order" issues* relate to the "intrinsic weaknesses" and the incomplete nature of current electricity markets in Europe. Twenty years after the start of liberalisation, the evidence is mixed regarding the achievements of liberalised power markets. Significant progress has been made toward integrating separate national markets, as many barriers to cross border trade have been removed, to the benefit of European consumers. The Third Energy package passed in 2009 represented a key milestone, and set forward a plan to implement a Target Model for electricity and gas markets in Europe by 2014. Whilst progress with the definition of some of the Framework Guidelines and Network codes is slowed down by a number of hurdles, regional initiatives have led to some significant successes in regional market integration. In particular, the implementation of market coupling on a regional basis has allowed some efficiency gains in the use of interconnections, and led to stronger price convergence between coupled markets.

But current electricity markets remain incomplete and the adequate price signals are lacking to provide the right operational and investment incentives to market participants. In fact, the evidence is growing that price signals are missing both on a very short time frame – within day or within the last hour before actual production – and on a very long time frame to trigger investments required to maintain security of supply.

The focus of the European Target model for electricity has historically been on the integration of day ahead power markets. But the development of intermittent renewables reinforces the **need to reward operational flexibility as well as dependability on short time frames**, both for flexible power plants and demand side response. The value of short term operating flexibility is typically captured through intraday and ancillary services, and there are concerns that such short term prices signals do not convey the proper scarcity value of operating flexibility in many countries, calling for revisiting the current arrangements for intraday trading and ancillary service procurement.

Another key issue with current electricity market arrangements concerns the **lack of incentives for investment, and safeguard mechanisms to ensure resource adequacy** – ie. that there will be enough supply to meet demand. The current debate on the introduction of "capacity mechanism" is grounded in the fundamental issue that energy only electricity markets do not provide adequate long term investment incentives, and cannot guarantee that there will be sufficient spare capacity for the lights to stay on.

Finally, European countries have different practices both in congestion management and in connection charges highlighting **the lack of a coordinated approach toward sending appropriate locational signals to electricity market players** in Europe. Failure to coordinate could increase the total electricity system balancing costs, and create tensions between different stakeholders as experienced recently between Germany and some of its neighbors. The issue is likely to grow as more renewables plants are connected to the European grid, as these plants are often located far from the areas with important load.

Conclusion and way forward: the need for a new market model

The solutions to Europe's electricity market issues can be classified in two broad categories which mirror the diagnostic. *"First order priorities"* include the need to reconcile the design of the target model for electricity market liberalisation and integration with the change in context. The trade offs between the liberalisation of Europe's electricity markets on the one hand side, and on the other hand the environmental policies in support of decarbonisation as well as the competitiveness and security of supply imperatives, need to be analyzed and addressed. The lack of consistency in the different policy packages is the root cause of many the regulatory and policy uncertainty that hampers investment.

In parallel, second order issues regarding the "intrinsic" incomplete design of the electricity market target model will need to be fixed. It is critical to complete the sequence of electricity markets with the missing elements in both the short term and in the long term. With the growth of intermittent renewables, the short term balancing of the system will rely critically on the implementation of liquid and integrated intraday, balancing and reserve markets. In addition, the implementation of capacity mechanisms in a coordinated way seems necessary to guarantee resource adequacy and security of supply in the long term. The design of electricity markets will also need to evolve to provide better locational signals so that production or demand response are located in nodes of the network where they are most needed.

Beyond these well these short-term reforms of the European target model**, a discussion needs to be initiated on the medium to long term model for electricity**

markets. Indeed, the evolution of the generation mlix toward capital intensive technologies, combined with the intermittent nature of some renewables technologies, imply that electricity markets rooted in the principle of short term marginal cost pricing will likely not be appropriate in the long term when renewables represent a dominant share of the generation mix. In concrete terms, the European electricity industry is moving from an “OPEX world” into a “CAPEX world”, and the market and regulatory framework will need to evolve accordingly. Some exploratory work needs to be launched to study alternative models for the long term, by e.g. learning the lessons from other industries with a costs structure dominated by fixed costs. A greater role for long term contracts can be envisaged as a way to transfer risks to consumers – which can be done in a competition enhancing way through the use of auctions as the experience in Latin America demonstrates.

ANNEX

Workshop participants

In September and October 2013, several meetings, workshops and informal discussions were held in order to hear the positions of some of the European stakeholders in the energy sector, two workshops in Paris, one meeting with the European Commission's Directorate-Generals for Energy, Climate, and Competition, informal discussions with E.ON, UFE or Eurelectric. We wish to thank all the participants to these debates. We owe special thanks to Gilles Bellec and to Claude Mandil for their active participation throughout the process.

16th of September: first workshop in Paris

Gilles Bellec, CGE, Conseil général de l'économie

Jean-Paul Bouttes, EDF, Executive Vice President Corporate Strategy and Prospective

Renaud Crassous, EDF, Senior Economist

Rachel Fletcher, OFGEM, Markets PA

Gwenaëlle Huet, GDF SUEZ Energie France, Director of European Affairs

Thierry Kalfon, GDF SUEZ Energie France, Director of Strategy, Economy and Tariffs,

Jan Horst Keppler, Paris-Dauphine University, Professor

Claude Mandil, Independent Expert, formerly Executive Director of the IEA and Deputy Chair of the Advisory Group on the Energy Roadmap 2050

Konstantin Staschus, ENTSO-E, General Secretary

Thomas Veyrenc, RTE, Director of Markets Department

1st of October: Meeting with E.ON

Vera Brenzel, Head of Political Affairs and Corporate Communications EU-Representative Office Brussels

3rd of October: second workshop in Paris

Richard Baron, OECD, Principal Advisor, Round Table on Sustainable Development

Manuel Baritaud, IEA, Senior Electricity Analyst, Gas, Coal and Power Markets Division

Sébastien Chiffaut, CRE, Head of Wholesale Market Surveillance

Paul Dawson, RWE Supply and Trading GmbH, Head of Market Design and Regulatory Affairs

Emmanuel Massa, CRE, Head of Pricing and Competition Department

Jean-Yves Ollier, Commission de régulation de l'énergie (French Energy Regulatory Commission, CRE), General Director

Charles Verhaeghe, CRE, Head of Cross-border Power Trade Department

15th of October: Meeting with UFE (Union française de l'électricité)

Jean-Jacques Nieuviaert, Senior Adviser

Jean-François Raux, Advisor to the Chairman and Board Member

Audrey Zermati, Deputy Chief Executive

18th of October: Meeting with the European Commission

Jozsa Balazs, Directorate-General for Energy, Policy officer, Unit A1

Inge Bernaerts, Directorate-General for Energy, DG Head of Unit Internal Market II: whole markets, electricity and gas

Antonin Ferri, French Permanent Representation to the European Union, Counsellor for Energy Policy

Tom Howes, Directorate-General for Energy, Deputy Head of Unit Energy Policy and Market Monitoring

Patrick Lindberg, Directorate-General for Competition, Unit B1, Case manager

Tadhg O'Brian, Directorate-General for Energy, Unit B2, Internal Market II

Christof Schoser, Directorate-General for Competition, Deputy Head of Unit B2

Stefaan Vergote, Directorate-General for Climate, Head of Unit A4

Joseph Wilkinson, Directorate-General for Energy, Unit A1

Mechthild Wörsdörfer, Directorate-General for Energy, Head of Unit A1

25th of October: Meeting with Eurelectric

Juan Alba Rios, Chair of the Markets Committee

Anne-Malorie Géron, Head of Markets Unit

Hans Ten Berge, Secretary General

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