European Electricity Markets in Crisis: Diagnostic and Way Forward

Mission du Commissariat Général à la Stratégie et à la Prospective[1]
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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 decarbonization 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.

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In the longer term, the ambition to decarbonize 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 decarbonization.

- **<u>First order issues: inconsistencies in European energy policy and interferences with electricity markets</u>**

The first order *"extrinsic issues"* have to do with the need to reconcile the electricity market liberalization and integration process with the new policy priorities in favor of decarbonization 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 decarbonized 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€/tCO2 for the past couple of years, well below the implied switching price between coal and gas fired generation (about 40€/tCO2), 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 liberalization, the evidence is mixed regarding the achievements of liberalized 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 liberalization and integration with the change in context. The trade offs between the liberalization of Europe's electricity markets on the one hand side, and on the other hand the environmental policies in support of decarbonization 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.

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Introduction – context and objectives of this report

Liberalization 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 crystalize some of these tensions between different policy objectives.

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 liberalization 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 liberalized 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 decarbonization 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 decarbonization 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 liberalization, 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 of the report concentrates on the "intrinsic issues" with electricity markets:

- Section 5 details the experience to date with European electricity markets liberalization, and highlights the achievements as well as the shortcomings of the liberalization 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.

Section 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 characterized by a profound transformation of the industry dominant technologies and business models.

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 utilization 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%

Source: IHS CERA

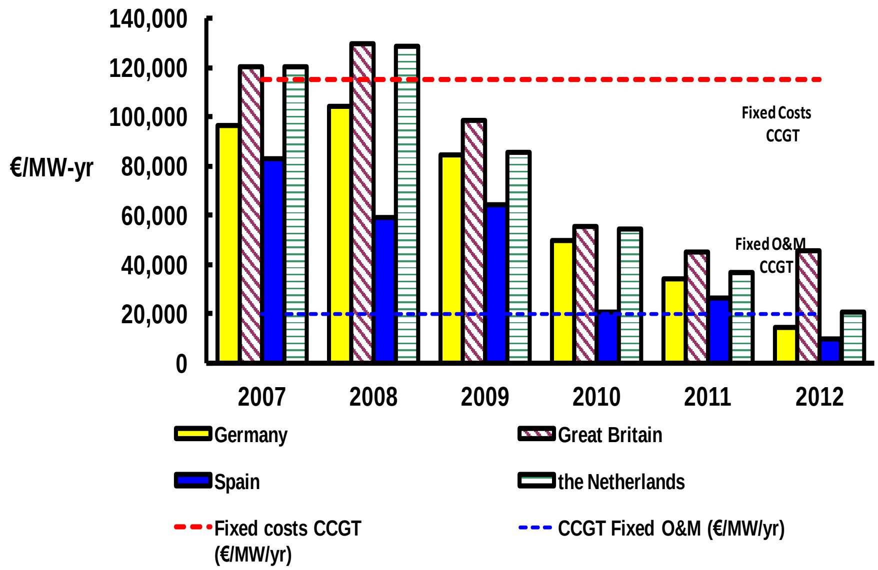
The final element of this perfect storm resides in the evolution of fuel, carbon and power prices. The oversupply situation that characterizes most European countries has led to a collapse of power prices to about 40 €/MWh, far lower than the long run total costs of even the cheaper technologies. Whilst 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.[3] 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.

[3] See IHS CERA Multi client study: Keeping Europe's Lights on: Design and Impact of Capacity mechanisms, August 2013.

Figure 1: Historical revenues for CCGTs compared to fixed O&M and total fixed costs (2007-2012)[4]



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[5]

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 jeopardize security of supply.

The long term decarbonization 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 CO2 emissions from the European economy ranging from 80 to 95% (see Figure 2). The decarbonization of the power sector is central to this objective, as the power sector represented in 2012 about 37% of the total CO2 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).

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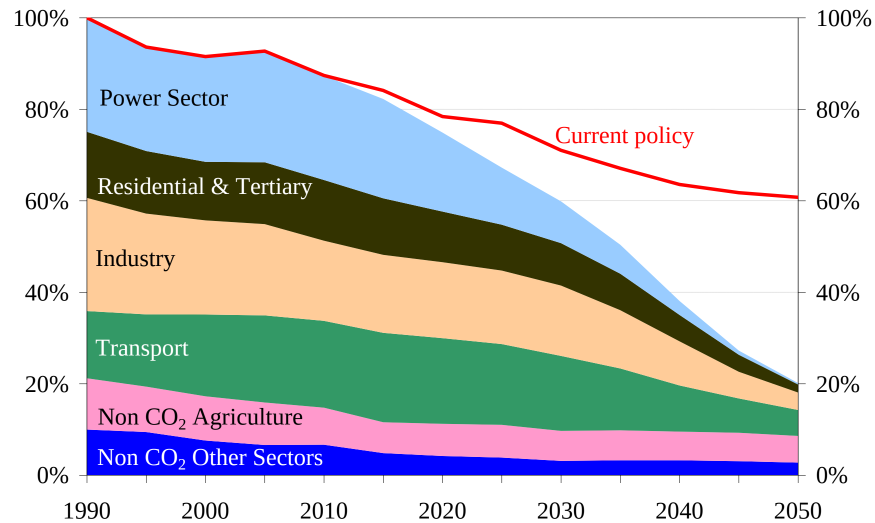
[4] Note: Notes: Sum of revenues made for a 55% efficient CCGT when hourly spot > variable costs. Variable costs based on gas spot prices (NBP for UK, TTF for NL and BCT for Germany).

[5] 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.

The decarbonization 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 decarbonization 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 decarbonization objective did not include references to the international context.

Figure 2 – European Commission 2050 decarbonization Roadmap: Evolution of CO2 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 decarbonization 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.

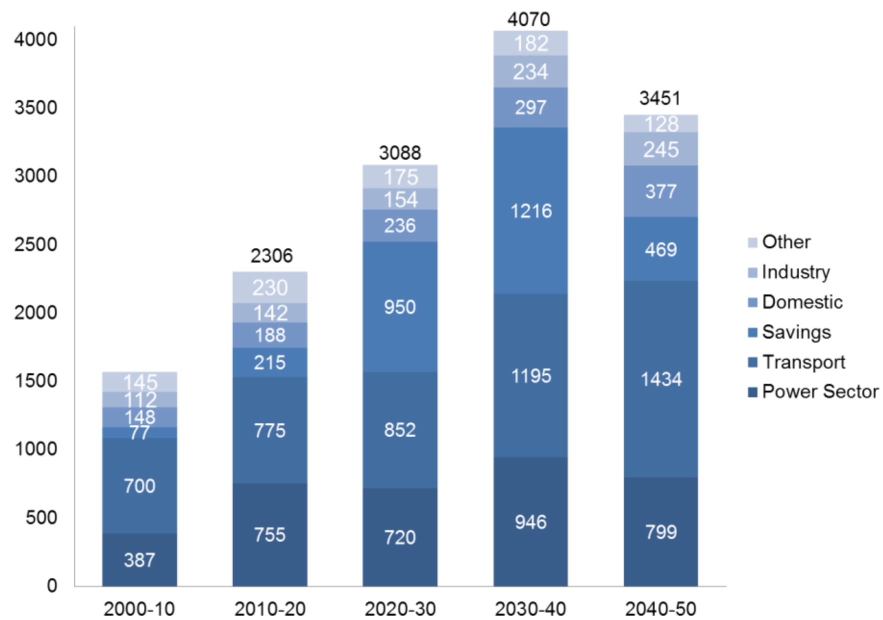
The deep political and technological uncertainties create a very uncertain context for the transition toward a low carbon electricity sector. Market players and regulators alike have to adapt to a changing environment and define a policy and regulatory framework that will be robust to a range of possible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

Section 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 decarbonize 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 decarbonize the European Economy.

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



Source: Eurelectric Power Choices Reloaded Study (2012)

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)

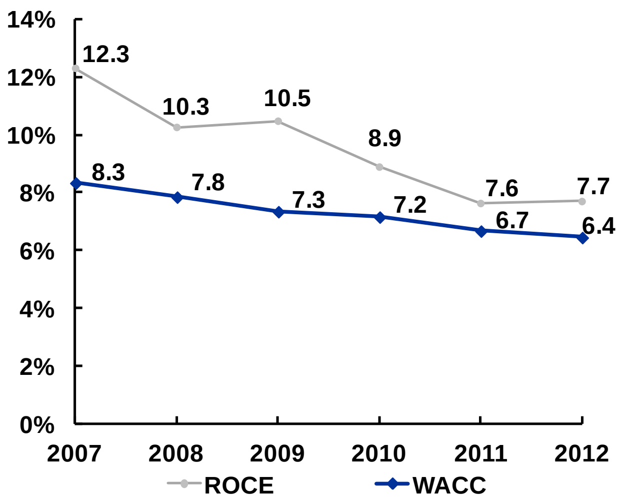
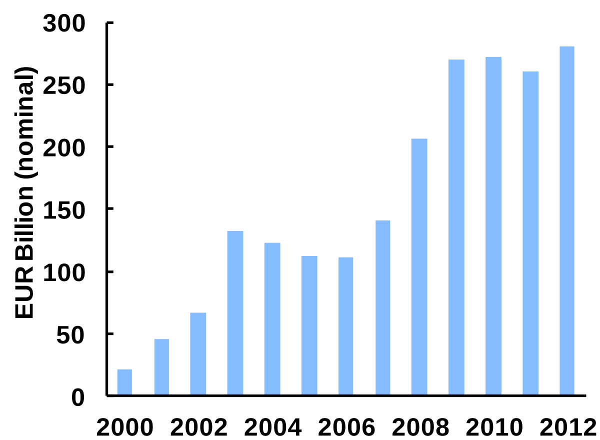


Figure 5 – Net debt evolution of 10 largest European utilities (billion Euros)



Source: IHS CERA 2012 European Policy Dialogue final report[6]

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 decarbonization 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 decentralized generation technologies will contribute to a sizeable part of the investments going

[6] 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.

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 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.

Section 3: The changing context for electricity market liberalization – 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.

Changing European energy policy priorities: combining liberalization with decarbonization 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[7]. 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[8].

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”.

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 decarbonize 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-

[7] Regulation (EU) No 994/2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC

[8] Communication "The EU Energy Policy: Engaging with Partners beyond Our Borders" [COM/2011/539]

sufficient by 2020.[9] 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, 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 liberalized 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 decarbonization 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.

Controlling the cost of clean technologies: pacing the energy transition

The economic crisis that has been characterized 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 – i.e. one household in seven.[10] Rising electricity prices

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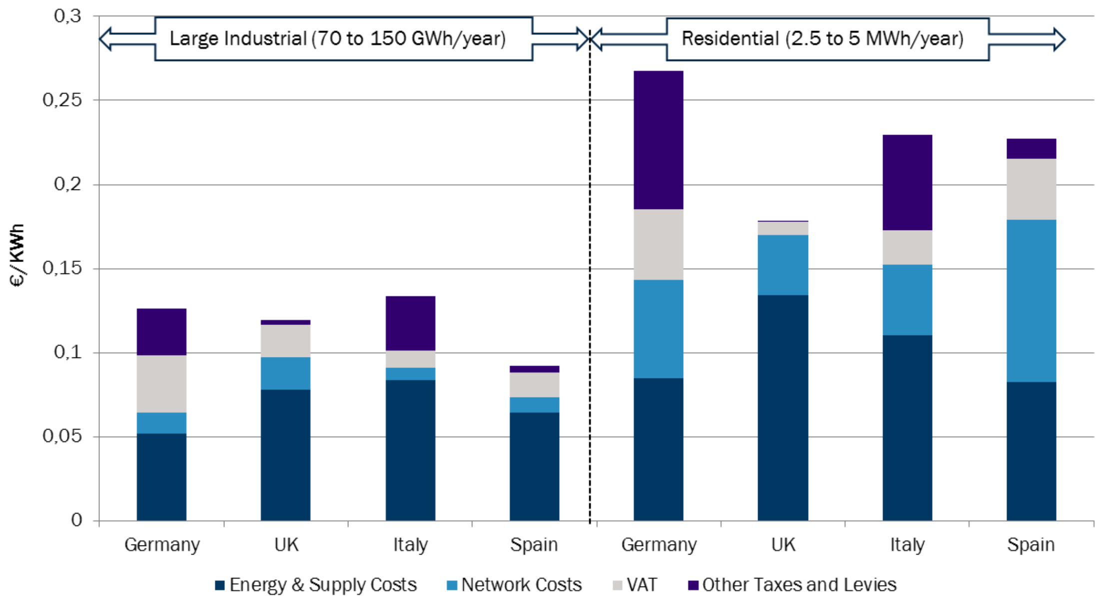
[9] See IEA World Energy Outlook, 2012 edition

[10] 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 http://www.fuel-poverty.org/files/WP7_D26-4_en.pdf

See also Ryan Walker, Harriet Thomson, & Christine Liddell, 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 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 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 decarbonization 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.[11]

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

The theory for electricity market liberalization was developed in the early 1980s in a very different context from today. One important element in the liberalization 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 commercialization of electricity. Whilst electricity production had been characterized 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.

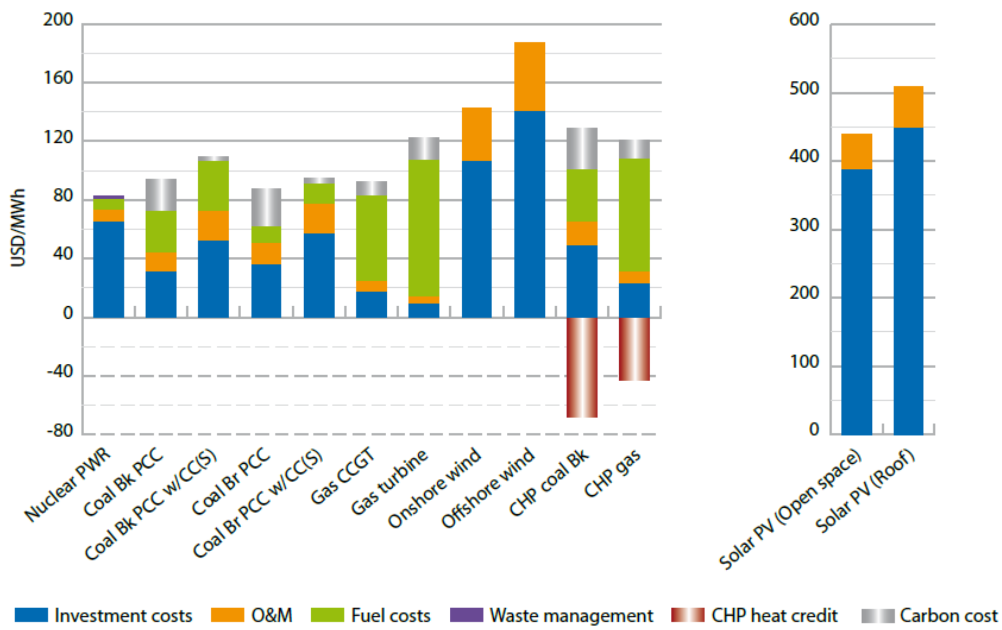
This market paradigm worked well to induce competition between technologies with significant variable costs, but will likely need to be adapted to reflect the recent changes in the technology costs structure of the generation mix. In the past four years (from 2009 to 2012), more than 60% of the capacity 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 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.

[11] Communication from the Commission of 10 January 2007 entitled: "Towards a European Strategic Energy Technology Plan" [COM(2006) 847 final-

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.[12] 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.

Section 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).

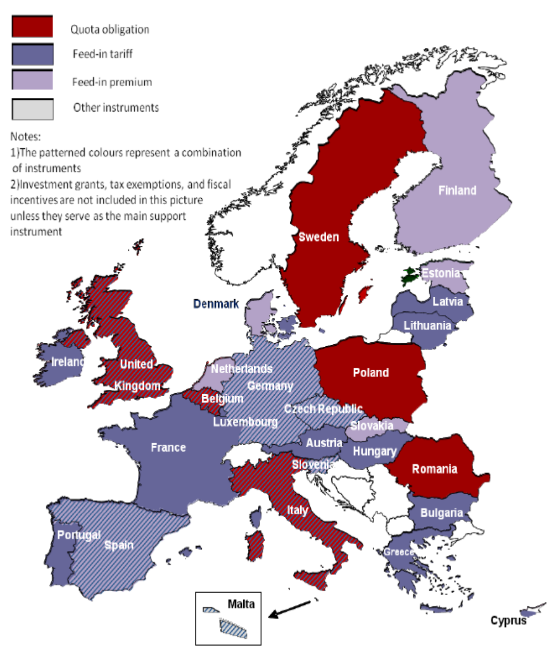
[12] See e.g. D. Finon & F. Roques, 2008. "Financing Arrangements and Industrial Organisation for New Nuclear Build in Electricity Markets," Competition and Regulation in Network Industries, Intersentia, vol. 9(3), pages 247-282, September.

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 tariff* 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)[13]

[13] R. Haas, Ch. Panzer, G. Resch, M. Ragwitz, G. Reece, A. Held. A Historical Review of Promotion Strategies for Electricity from Renewable Energy Sources in EU Countries , Renewable and Sustainable Energy Reviews, volume 15, issue 2, pp. 1003 – 1034 (2011).

There is a large academic literature and practitioner's evidence on the pro and cons of the different schemes.[14] 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.[15]

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 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.

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 penalize 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 int eh 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.

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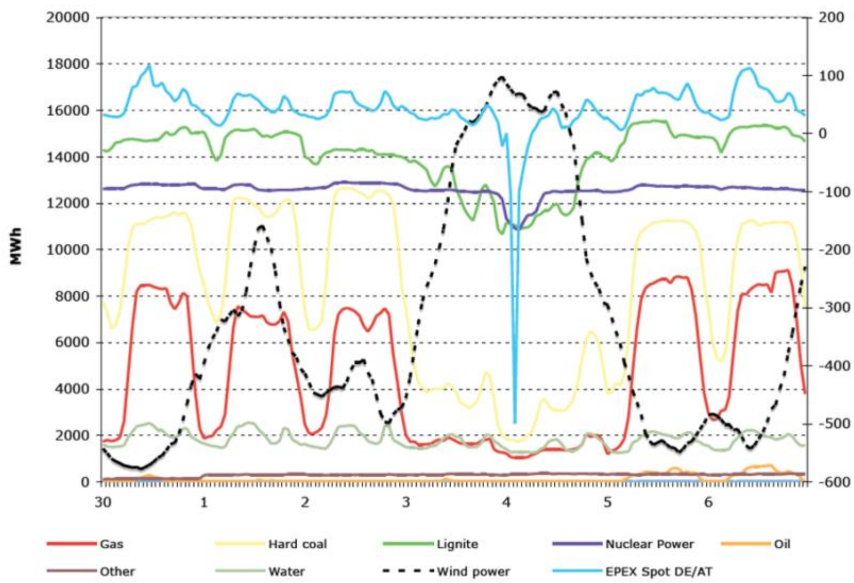
[14] See eg. C. Hiroux & M. Saguan (2010), Large-scale wind power in EU electricity markets: Time for revisiting supports and market designs? - Energy Policy, Volume 38, Issue 7, July 2010, Pages 3135–3145. M. Ragwitz, S. Steinhilber. Effectiveness and efficiency of support schemes for electricity from renewable energy sources , accepted for publication at WIREs Energy Environment (2013).

[15] See e.g. Roques, Fabien & Hiroux, Céline & Saguan, Marcelo, 2010. "Optimal wind power deployment in Europe--A portfolio approach," Energy Policy, Elsevier, vol. 38(7), pages 3245-3256, July.

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

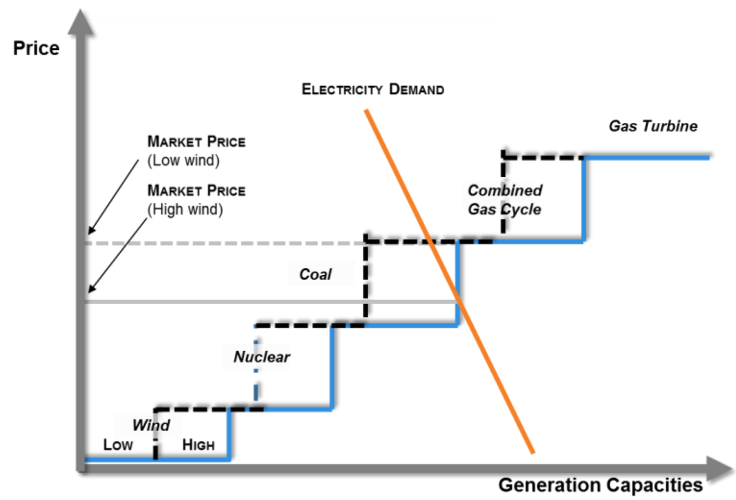
Renewables displace thermal plants in the merit order and amplify the missing money issue

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 amortization phase, it can lead to significant stranded costs and destabilize 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



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 decarbonized energy mix.[16] 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€/tCO2 for the past couple of years. In comparison the implied switching price between coal and gas fired generation ranges from 40 to 50€/tCO2 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 equalize their long run generation costs with a combined cycle gas turbine (about 70 €/MWh) are respectively 240 €/tCO2 and 430 €/tCO2.

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

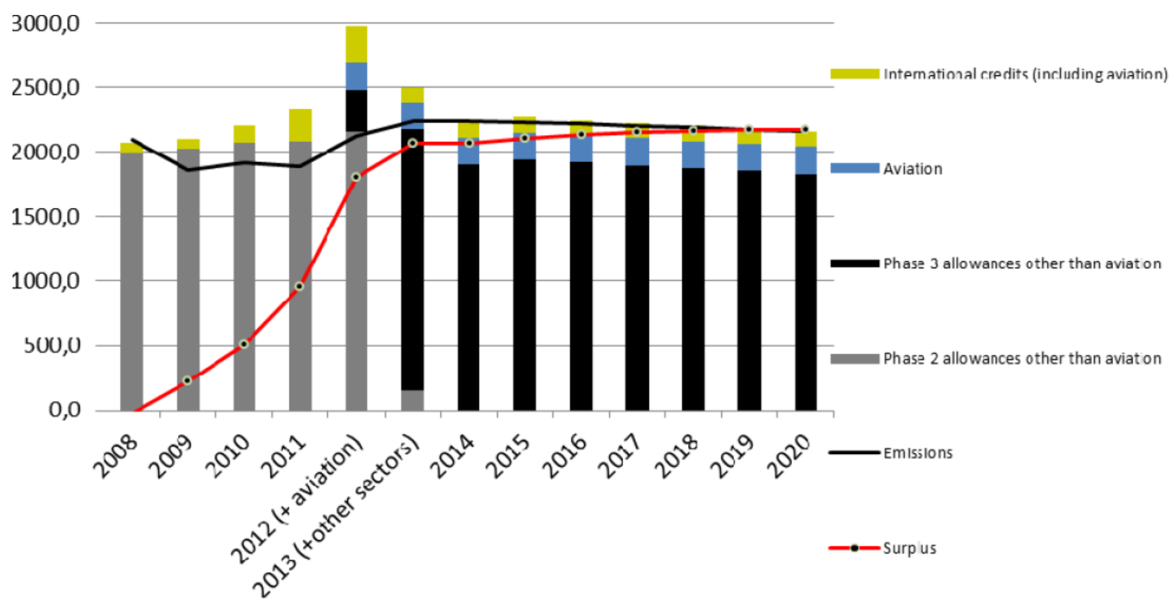
[16] The European carbon Trading Scheme (ETS) currently covers close to half of the European Union's emissions of carbon dioxide (CO2).

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 2021–30, 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 CO2 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 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)[17]



Source: European Commission, State of the European Carbon market

[17] European Commission (2012). The state of the European carbon market in 2012. 14.11.2012, COM(2012) 652 final

Section 5: Successes and issues with European electricity markets integration

20 years after the start of liberalization, first in the UK and in the Nordic countries, and then in the rest of Europe, the evidence is mixed regarding the achievements of liberalized power markets.

The three Directives in December 1996, June 2003 and July 2009 represent the key milestones for the coordination and integration of electricity 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.[18]

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 harmonized 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 harmonized 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.

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.

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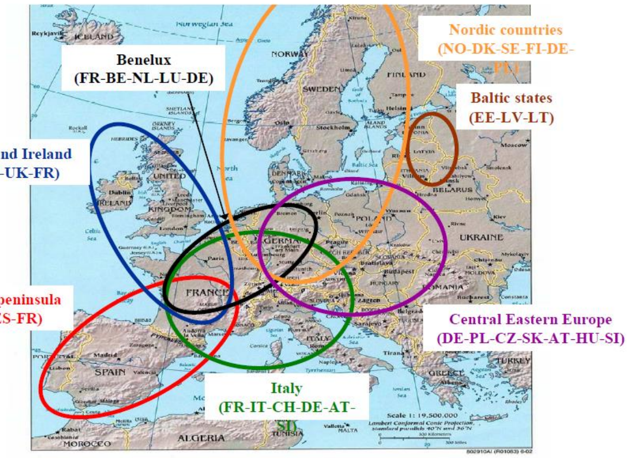
[18] The Sector Inquiry identified the following issues:

- “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.”

Figure 12: The Seven Regional Initiatives



Source: Everis and Mercados (2010)[19]

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.[20] 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 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.

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 2012-22.

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[19] From Regional Markets to a Single European Market, Everis and Mercados (2010).

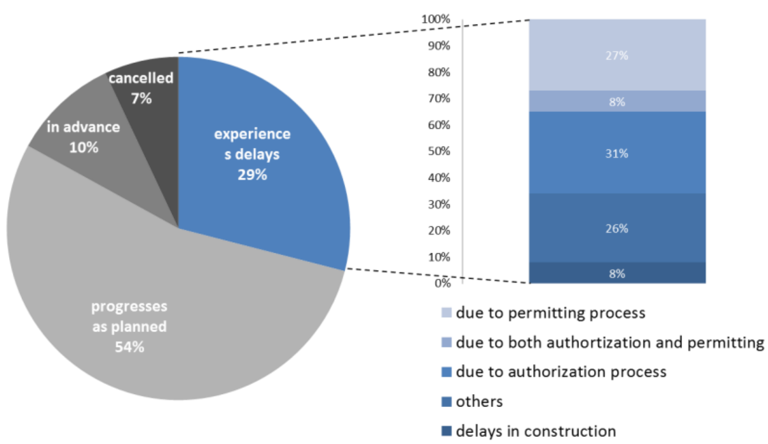
[20] Market coupling in wholesale power markets uses implicit auctions in which players do not receive allocations of cross-border capacity themselves but bid for energy on their exchange. The exchanges then use the Available Transmission Capacity (ATC) to minimize the price differences between two or more areas. In so doing, market coupling optimizes the interconnection capacity and maximizes 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.

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[21]. 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 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 authorization 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.

[21] 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

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.[22]

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.

Section 6: Incomplete electricity markets and the missing price signals

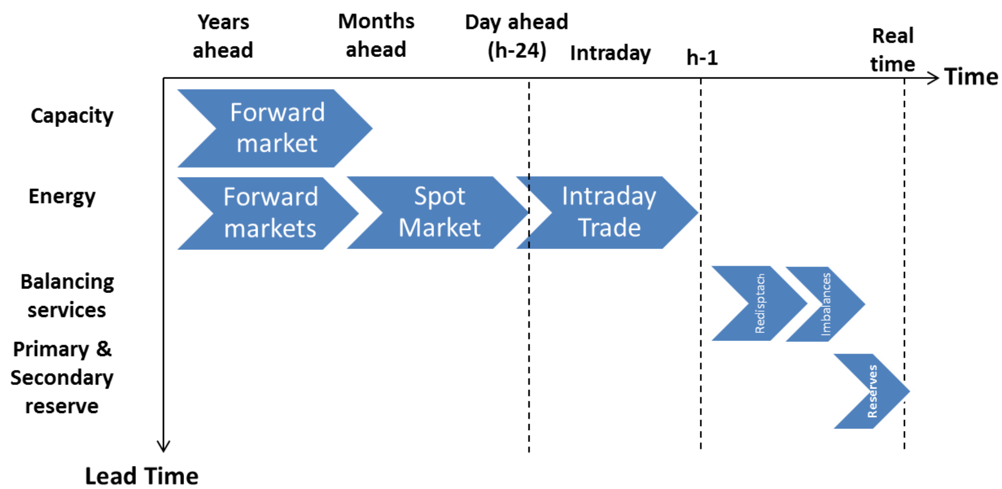
The initial design of electricity markets focused on implementing the textbook model of competitive day ahead power markets accompanied by intraday balancing under the control of the system operator.[23] Different countries followed different routes, with the center of Europe going for mandatory pool type centralized arrangements (Spain, Italy, the Nordics, Ireland, the UK initially), whilst the rest of Europe did go for decentralized voluntary markets relying on voluntary bilateral trading.

[22] Booz & Company. 20 July 2013. Benefits of an integrated European energy market. Prepared for: European Commission Directorate-General – Energy

[23] See for instance Joskow, P.L. and R. Schmalensee. (1983). *Markets for Power: An Analysis of Electric Utility Deregulation*, Cambridge. MIT Press.

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 realized that a sequence of decisions 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. The blocks in orange show the missing or insufficiently developed markets.

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.

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 organization (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 centralizes 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.[24]

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 harmonize approaches and encourage cross-border exchanges of balancing energy.

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.

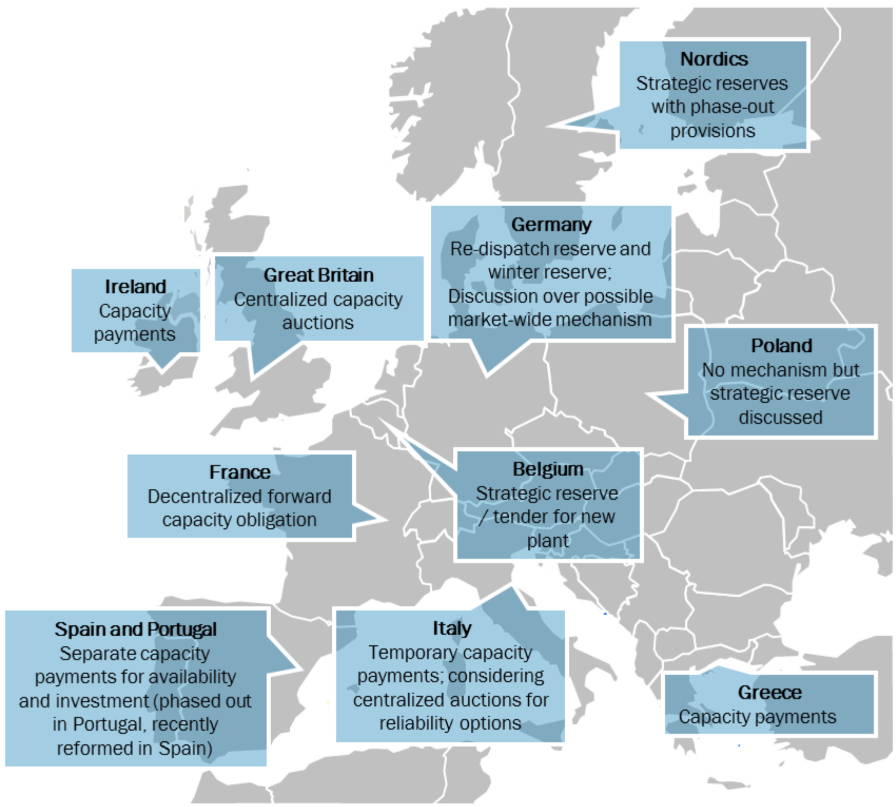
However, the evidence is growing that for a variety of reasons - ranging from operational price caps to the political unacceptability of very high power prices – that power prices are not allowed in practice

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

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.[25] 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.[26]

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

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[25] See for instance Finon D. et V. Pignon, 2008, "Electricity and Long–Term Capacity Adequacy, The Quest for Regulatory Mechanism Compatible with Electricity Market", Utilities Policy

[26] See eg. LJ De Vries (2007). Generation adequacy: helping the market do its job. Utilities Policy 15 (1), 20-35

Or Fabien Roques (2008). Market design for generation adequacy: Healing causes rather than symptoms, Utilities Policy, Elsevier, vol. 16(3), pages 171-183.

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 harmonized, at least coordinated approaches on a regional basis.

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 optimize 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 maximizes 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:[27]

- 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 characterized 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 king of location signals for both operations and/ or investment.

[27] See ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2011 - 29 November 2012

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 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.[28]

[28] ACER has recently launched a consultation on revisiting current bidding zones, see: http://www.acer.europa.eu/Official_documents/Public_consultations/Pages/PC_2013_E_04.aspx

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 liberalization and integration of electricity markets, but rather the need to reconcile this process with the new policy priorities in favor of decarbonization 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:

- 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 decarbonization 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 decarbonization 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 decarbonization.

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 liberalization and integration with the change in context. The trade offs between the liberalization of Europe’s electricity markets on the one hand side, and on the other hand the environmental policies in support of decarbonization 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 decarbonization?
- 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 decarbonization?
- 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 optimization. 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".[29]

[29] For more discussion of these issues, see e.g. Dominique Finon and Fabien Roques (2013). European Electricity Market Reforms: The "Visible Hand" of Public Coordination. Economics of Energy & Environmental Policy Volume 2, Number 2. Available at: http://www.ceem-dauphine.org/assets/wp/pdf/Finon_Roques_Visible_Hand1.pdf