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Investment perspectives in electricity markets

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Launching the public consultation process on a new energy market design

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ABBREVIATIONS AND SYMBOLS USED

COUNTRIES

AT	Austria
BE	Belgium
BG	Bulgaria
CY	Cyprus
CZ	Czech Republic
DE	Germany
DK	Denmark
EE	Estonia
EL	Greece
ES	Spain
FI	Finland
FR	France
HR	Croatia
HU	Hungary
IE	Ireland
IT	Italy
LT	Lithuania
LU	Luxembourg
LV	Latvia
MT	Malta
NL	Netherlands
NO	Norway
PL	Poland
PT	Portugal
RO	Romania
SE	Sweden
SI	Slovenia
SK	Slovakia
UK	United Kingdom
US	United States

UNITS

GWh	Gigawatt hour
kWh	Kilowatt hour
Mtoe	Million tonnes of oil equivalent
MWh	Megawatt-hour
tCO2	Tons of carbon dioxide emissions
TWh	Terawatt-hour

OTHERS

CAPEX	Capital Expenditure
ECM	Error correction model
EEX	European Energy Exchange
EIA	Energy Information Administration
ENTSO	European network of transmission system operator
ETS	Emissions trading scheme
EU	European Union

EUA	European Union allowances
EUR	Euro
FiT	Feed-in tariff
GDP	Gross Domestic product
GHG	Greenhouse gas
HHI	Herfindahl-Hirschman index
HICP	Harmonized index of consumer prices
IEA	International Energy Agency
LCOE	Levelised Cost of Electricity
LRMC	Long run marginal cost
MS	Member State
OCGT	Open-Cycle Gas Turbine
OECD	Organization for Economic Cooperation and Development
OPEX	Operating expenditure
RES	Renewable energy sources
VOLL	Value of Lost Load

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EXECUTIVE SUMMARY

The EU has confirmed its intention to decarbonise its economies

The decarbonisation of EU economies is at the core of the EU's agenda for climate change and energy. The Climate and Energy Package adopted in late 2008 targets require the EU's Member States to cut their greenhouse gas emissions by 20 %, to produce 20 % of their energy from renewable sources, and to reduce their gross primary energy consumption by 20 %. In 2009, this agenda was complemented by the aspirational goal of reducing greenhouse gas emissions by 80-95 % by 2050. These ambitions were reaffirmed in October 2014, when Member States agreed to set targets for 2030 of 40 % for domestic greenhouse gas emissions reduction, at least 27 % for the share of renewable energy and at least -27 % for energy consumption.

The substantial investment in low-carbon technologies that will be needed to achieve these goals will have to be supported by an economic and institutional framework capable of facilitating this transition. The power sector is likely to play a central role in the energy transition. First, it has been the main sector experiencing decarbonisation since the last decade and its challenges still remain high. Second, in the near future, the power sector is expected to support the economy in reducing its dependence on fossil fuels, notably in the transport and heating and cooling sectors. For this reason, the cost effective promotion of private and public investments in this sector will be crucial so that consumers can reap the benefits of this strategy. This report provides analysis of the key challenges for investments in the electricity generation sector and reviews how to improve the current market arrangements or to introduce possible new ones that that could improve the current and future investment framework.

Investment in new generation capacity is increasing…

Investment in the EU's electricity generation sector has not been affected by the economic crisis and has even been accelerating since 2009. Between 2004 and 2012, capacity increased by 30 % in the EU, in comparison to just 10 % in the US. As a result the share of renewable energy in the EU's electricity mix has continued to rise since 2008.

… in a context of increasing public support

As with investments in other sectors of the economy, investments in electricity generation are in general driven by market conditions. They can, however, benefit from various forms of public support, provided these are in line with EU state aid rules. Public support may have different objectives, such as security of supply, environmental concerns or social inclusion. With the increasing production of renewable electricity, the support to these new technologies rose to € 40 bn in 2012, financed mostly by end-user consumers through levies on retail electricity prices. As a result, retail prices have increased for households and, to a certain extent, industries.

… and a weakening investment price signal

By contrast, the opposite trend was observed on wholesale markets. Market prices for fossil fuels have decreased since oil prices peaked in 2008. Despite a rebound in 2009-2010, oil prices have been declining since 2011. Wholesale power prices have followed the same evolution, lowering the expected profits of investors. Moreover, due to the sharp decline in the price of CO2 emission allowances, the use of high carbon emitting power plants and the investment in them has only been discouraged to a certain extent. An empirical analysis of the drivers of wholesale electricity prices shows the importance of electricity demand, as the main determinant of prices. This confirms that the economic crisis, by lowering electricity demand, has played a major role in depressing wholesale electricity prices. However, the results

also suggest that renewable energy production had a downward impact on wholesale prices as their market penetration has grown, which could be interpreted as an indication of structural changes on the market.

… wholesale electricity prices still matter for competitive technologies

The investment framework has also undergone considerable changes. On the one hand, investments in maturing, clean technologies have taken place thanks to public support, which reduced the capital and operating costs and the risks for investors. On the other hand, investment in conventional technologies has been influenced by fundamental factors that matter for investors. The report includes an empirical analysis of investment drivers in conventional technologies. The results confirm the importance of the price signal as a trigger for investments in mature energy technologies, but also points to the influence of macroeconomic factors such as interest rates, competition and a favourable business environment.

Today, in wholesale electricity markets, power prices are set by the bid of the marginal unit. This is achieved mostly within day-ahead markets as currently other markets such as intra-day markets are not sufficiently developed. Under the assumption of perfect competition, bids represent the marginal costs of the plant to supply energy. But the role of the market price signal varies across market frameworks. In energy-only markets, the stability of the system in terms of new investments in capacity is achieved through price signals. When electricity demand is higher, prices increase to signal scarcity. This increases the profits of generators and gives them the incentive to invest. In other market frameworks, the energy market can be complemented by a capacity mechanism. In such markets, generators get revenues from electricity trading (energy market), but also get remunerated for their available capacity in the market.

… but the rising penetration of low-carbon technologies is changing investment conditions

The rising penetration of low-carbon technologies represents a challenge for the electricity sector under the current market arrangements. As their share of production increases, electricity markets will increasingly be dominated by units with low operating costs but high initial capital costs. The risk is that under current market arrangements and without further integrating existing markets, wholesale market price may prove too low to trigger the necessary investments in generation capacity. In such a situation, it needs to be evaluated if generators would require some additional forms of remuneration, which would have to be borne by consumers or tax payers and would need to stand in proportion to the benefits provided.

According to Commission estimates, the power sector will require up to EUR 90 billion of investment a year until 2030, of which EUR 50 billion are needed in energy generation and EUR 40 billion are needed in power grids. The high investments needs and the changing investment environment call for a reflection on the effectiveness of current market arrangements to drive investments.

The transition to a low-carbon economy impacts both capacity and prices

This report contributes to the current debate on market design by discussing the consequences of decarbonisation in a competitive market environment and by providing an analytical framework to understand the transition to a low-carbon economy. The analysis aims to describe the consequences of decarbonisation on the investment environment under current market arrangements. On this basis, the analysis identifies possible challenges that

the EU could face during and after its transition to a low-carbon economy. Today, the transition is still ongoing, but markets will soon face a larger share of low carbon technologies. Investments in electricity generation are long-term by nature and investors need to assess their future profitability before deciding to invest today. The challenges of the transition phase will differ during its different stages of completion and therefore need to be well understood in order to be successfully addressed.

Under current market arrangements, the rising penetration of low-carbon technologies is likely to put pressure on wholesale market revenues during the transition phase. This may make it difficult to achieve the necessary levels of investment, and non-competitive low carbon technologies may still require some form of support. At the same time, the market is likely to face overcapacity, which will need to be addressed in order to reduce the costs of the transition. Once decarbonisation has be achieved, the issue of market revenues may become even more salient, as the cost structure of the technology mix based on low variable costs and high fixed costs could challenge the ability of market prices, formed today mostly on day-ahead markets, to allow investor to recoup their costs. As a result there could be a risk that investors may not be able recoup their investments under the current forms of market arrangements (especially in view of the existence of price caps, market fragmentation and imperfect competition).

… as a result, market arrangements may need to evolve

The report explores further possible avenues to tackle the investment challenges identified in the analysis and brought about by the transition. The central objective of any market arrangement should be to minimise public support in order to make the penetration of low-carbon technologies cost effective for end-consumers and society at large. Therefore, the report reviews how the existing market arrangements can be improved and which ones could be deployed for the transition phase. The aim of such arrangements would be to deepen market integration, make effective use of the carbon price signal, ensure the phasing out of high CO2 emitting technologies in the short run and reinforce the spot price signal.

In the long run, the challenge will be to put in place market arrangements that provide sufficient revenues for investments to take place without any form of State intervention. Given the investment challenges that successful decarbonisation may create, there is a need to start reflecting on the most suitable market arrangements for the transition phase and on the type of market arrangements that Europe will need once it has reached its decarbonisation goals.

Part I

Investments in electricity markets: evolution and drivers

INTRODUCTION

This part describes the changing pattern of electricity investments over the past decade. EU electricity markets have been reshaped by regulatory reforms starting in the 1990s, and by the decarbonisation agenda and the adoption of targets to reduce greenhouse gas emissions and increase the share of renewables in energy consumption.

Chapter one describes the recent evolutions of investments in electricity markets. Investment in electricity generation in the EU has been steadily increasing over the last fifteen years. This trend has been driven by the energy and climate change policy agenda and has led to a significant increase in the proportion of electricity generated from renewables. Such an evolution would not have been possible without any forms of public support at production, demand or investment level. The last section highlights the divergent path of retail and wholesale electricity prices. Retail prices for both households and industries have risen largely. Wholesale prices, by contrast, have fallen in recent years due to a number of factors including lower commodity prices, the economic slowdown and higher production from renewables.

Chapter two discusses and analyses the investment drivers in electricity markets. First the analysis focuses on renewable technologies as investments in these new technologies were mostly driven by the policy agenda and the resulting public support. By contrast, investments in conventional technologies were mostly driven by macro-economic and energy specific factors. The econometric analysis carried out in this chapter shows that the price signal matters for these mature technologies along with other economy-wide factors such as demand, competition and financial conditions.

1. INVESTMENTS IN ELECTRICITY GENERATION: RECENT TRENDS

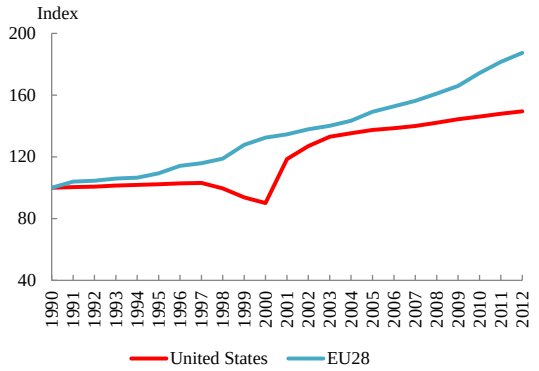
The electricity generation sector is experiencing a transformation driven by the EU policy climate and energy agenda. Generation technologies are changing in response to climate change policy as well as to security of supply concerns. At the same time, the reform of the sector through market opening is putting competitive pressure on utilities to improve the efficiency of their operations.

This chapter focuses on the electricity sector and describes the recent evolution of investment in electricity markets. Section 1 analyses the evolution of installed capacity over the period 2004 – 2013 in the Member States. Section 2 describes the increase in public support to electricity over the period. Section 3 looks at the electricity price evolution in relation to coal, oil and CO2 prices. Section 4 concludes.

1.1. INVESTMENT TRENDS IN ELECTRICITY GENERATION

Investments in power generation in the EU have continued to expand over the last 15 years. The evolution of capacity in the EU followed a steady increasing trend. Compared to the US, where the increasing trend was interrupted by a break between 1998 and 2000, growth of capacity in the EU followed a more stable and faster increasing trend, which accelerated starting in 2009 (Graph I.1.1).

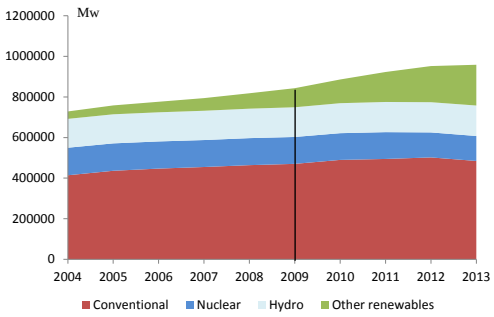
Graph I.1.1: **Evolution of installed generation capacity**



In the OECD database capacity is defined as capacity at 31st December including electrical capacity of both electricity (only) and CHP plants
Source: OECD and Eurostat

Generation capacity in the EU increased sharply from 2009 onwards due to the addition of new renewables technologies on the already existing capacity. The composition of the capacity mix progressively changed: nuclear capacity started declining in recent years (2010-2013) due to phasing out decisions in some Member States. Conventional capacity showed a decline in 2012-2013 (Graph I.1.2).

Graph I.1.2: **Installed generation capacity - EU28**



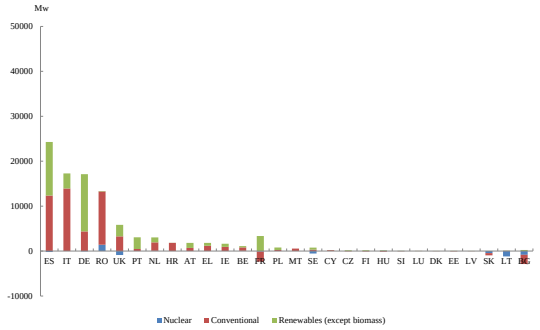
Other renewables includes wind, solar, geothermal and tidal.
Conventional includes combustible fuels
Source: Eurostat

Investment in electricity generation capacity in the post-crisis period was of greater magnitude than pre-crisis. During the period 2004-2008, generation capacity modestly increased in some Member States (Graph I.1.3). For example, 25 GW

were added in Spain and 17 GW in Germany. Between 2008 and 2012, instead, a period which coincided with the development of renewables, capacity additions were much more significant, with 35 GW of additional capacity in Spain and 51 GW in Germany. The same evolution can be observed in other Member States, like Italy, Portugal, Greece, Romania, the United-Kingdom, France, Netherlands, Czech Republic, Poland, Sweden, and Denmark. This phenomenon was mainly driven by the increase in renewable installed capacity, accompanied by a more modest increase of conventional technologies.

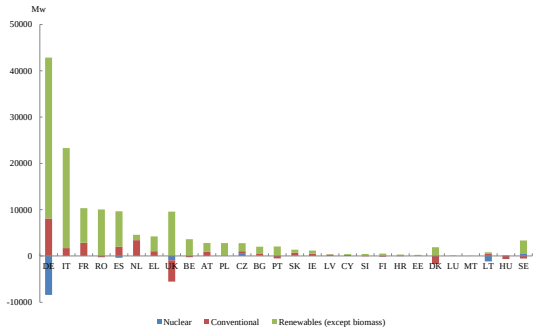
At the same time, Member States are not following the same investment trends. Between 2009 and 2013, a majority of Member States (Germany, Italy, France, Romania, Spain, Greece, the United Kingdom, Belgium, Austria, Poland, Czech Republic, Bulgaria, Portugal, Slovakia and Ireland) increased their overall generation capacity, while for the rest there was little change in generation capacity and for some even a decrease (notably Sweden)([1]). With respect to investment in low carbon technologies, in Germany, Italy, France, Romania, Spain and the United Kingdom, renewable capacity increased quite substantially, whereas in the Netherlands additions in conventional capacity were larger than in renewables. France stands out as a country where conventional capacity decreased in the period 2004-2008 whereas there were additions in conventional generation in 2009-2013. In Germany, instead, where renewables increased significantly during 2009-2013, additional conventional capacity was built also due to the phasing-out of nuclear power plants (Graph I.1.4).

Graph I.1.3: **Net change in installed generation capacity 2004-2008**



Conventional includes fossil fuels and other sources. Renewables includes hydro, solar, wind, tidal, geothermal.
Source: Eurostat, Energy Statistics

Graph I.1.4: **Net change in installed generation capacity 2009-2013**



Conventional includes fossil fuels and other sources. Renewables includes hydro, solar, wind, tidal, geothermal. For Sweden due to lack of data, it is assumed that the hydro capacity in 2013 is the same as in 2012.
Source: Eurostat, Energy Statistics

1.2. PUBLIC SUPPORT

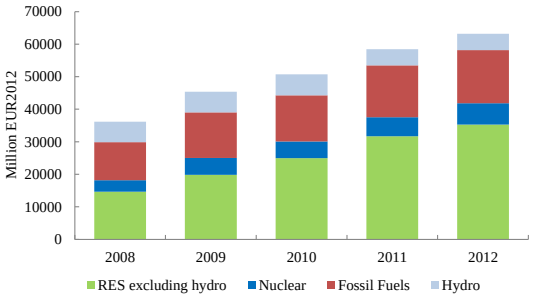
The expansion of capacity of the period 2008-2012 was accompanied by policy efforts, in the form of increased public support to the sector. Public support is a type of state intervention, which can take the form of direct transfer of funds, targeted tax allowances and exemptions, investment tax deductions, loan guarantees, price support, price caps, and price guarantees. Arguably, public support to energy has always been used to reach some policy objectives such as energy independence, social inclusion, environmental goals, or competitiveness exposure of energy intensive industries. More recently, the

([1]) It needs to be noted that the calculations in Graphs I.1.3 and I.1.4 show the net change in capacity, and not the total size of investment that took place in the different Member States. Hence, decommissioning of one type of generation can in principle mask the actual size of investment in one category or the other. For instance, decommissioning of large hydro installations makes the resulting net change in renewable capacity smaller.

development of the new low carbon technologies and the need to secure a new investment path has triggered new forms of support to deployment.

The total amount of public support to the electricity sector increased over the period 2008-2012 from EUR36 to EUR63 billion ([2]). Public support increased both for fossil fuel and renewable technologies, even though the latter accounted for most of the increment: support to renewables grew by 93% compared to 39% for fossil fuels (Graph I.1.5).

Graph I.1.5: **Total support to the energy sector**



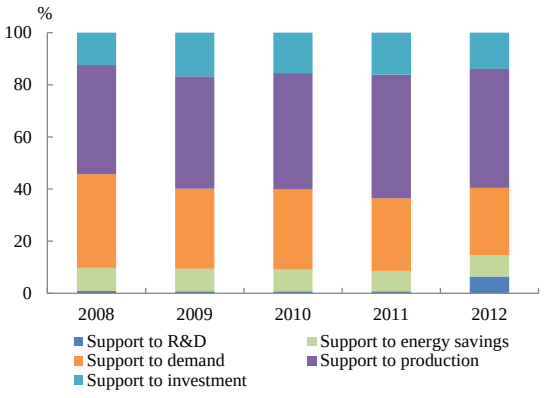
Total support is the sum of five categories: support to energy demand, support to investment, support to production, support to energy efficiency and support to R&D.
Notice: the graph figures do not include external costs.
Source: Own calculations based on ECOFYS, 2014

Support to production constitutes the main share of total support (around 45%). It includes, among others, exemptions from fuel taxes, feed-in tariffs and premia, tradable certificates for renewable energy quotas, and support to decommissioning. The increase in support to production can be explained by the increase of renewable technologies in the fuel mix. This new renewable capacity was mainly installed with the support of feed-in schemes. In the majority of Member States, most of this support has been financed by consumers through levies or surcharges, while in a few cases it has been financed through general taxation ([3]).

Support to energy demand accounts for 30% of total support. It is granted to the demand side rather than to generators and is mainly constituted by energy and VAT tax exemptions, price guarantees (in the form of social tariffs for electricity set below a reference price or the provision of fossil fuel below costs as inputs to electricity generation), and interruptible load schemes, by which payments are provided to electricity consumers that agree to be switched off remotely where the system requires it.

In comparison, the other forms of support were smaller. Support to investment follows support to demand with a share of approximately 14%; support to energy savings has a share of 8%. Support to R&D was very low compared to the support granted to all other sectors (support to production, to investment, to energy saving and to energy demand) up until 2012, when it hit 6% of the total ([4]).

Graph I.1.6: **Components of total support**



Source: ECOFYS, 2014

1.3. PRICE EVOLUTION: ELECTRICITY, CARBON AND COMMODITY PRICES

Trends in electricity should be interpreted in the wider context of the macro economic framework in the energy sector, which have an impact both in the retail and wholesale market.

([2]) These figures refer to the value in EUR2012 of support provided to renewables, fossil fuel and nuclear technologies in the form of production and investment support and do not include other costs of electricity.
([3]) European Commission (2014a).
([4]) R&D support reported in the study might be under-estimated. The Strategic Energy Technologies Information System (SETIS) reported that public R&D spending on low carbon energy technologies in the EU (both at EU and Member States level) amounted to about EUR 1.5 bn per year in 2007 and EUR 3 bn per year in 2011. Data available at https://setis.ec.europa.eu

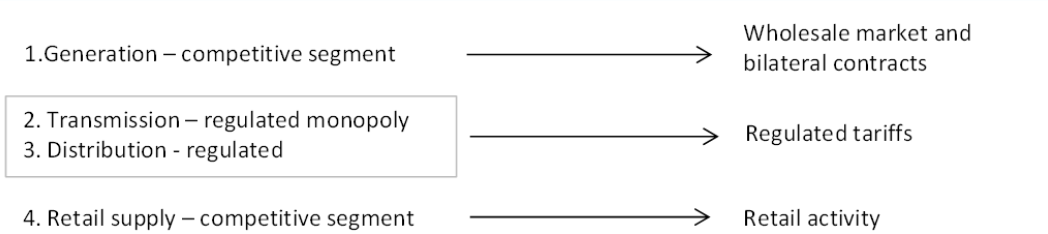
Box I.1.1: Electricity Markets and Policy Context

Market opening

Following market opening starting in the 1990s, the electricity supply chain was restructured from a vertically integrated utility company, generally a national monopoly, into four different segments: generation, transmission, distribution and retail. Among these segments, one market is regulated, the network part which comprises transmission and distribution segments, and two are competitive, the generation and retail market.

The role of the wholesale market is to create a space where generators meet retailers and other financial intermediaries. Due to the currently limited storability of electricity and other physical constraints, there is the need for an intermediary between generation and final supply to always keep the balance between the electricity produced and consumed. This intermediary is the transmission system operator (TSO), which maintains the system balance by ensuring that balancing responsible parties have a clear incentive to guarantee continuous and uninterrupted availability of electric power. Transmission and distribution are natural monopolies and are subject to regulation that defines what network operators can charge clients. From transmission and distribution, electricity is sold to final consumers on the retail market. The retail electricity market consists in the exchange of power and services at the lower-voltage distribution level (distribution and supply). In principle, this is a competitive and dynamic market, where customers can choose their provider among competing suppliers and freely switch from one to another ([1]).

Graph 1: **The electricity value chain after market opening**



Source: European Commission

Decarbonisation

In addition to the structural changes brought about by market opening the energy system underwent radical changes due to the introduction of increasingly ambitious low carbon policies, developed with the objective of reducing the environmental impact of the EU energy sector and to improve energy supply independence. The 20-20-20 climate and energy package of 2009 includes three targets to be met by 2020: 20% GHG emission reductions compared to 1990 levels; 20% share of renewables in energy consumption; 20% improvement in the EU's energy efficiency. The emission reduction objective was restated by EU leaders in October 2014 when they adopted the 2030 framework for climate and energy policies ([2]). A centre piece of the framework is the binding target to reduce EU domestic greenhouse gas emissions by at least 40% below the 1990 level by 2030. The 2030 framework also includes a target of 27% of renewable energy in total energy consumption binding at EU-level, as well as an increase of 27% in energy efficiency.

([1]) From the encyclopaedia of the European University Institute.
([2]) European Council 23/24 October 2014 – Conclusions

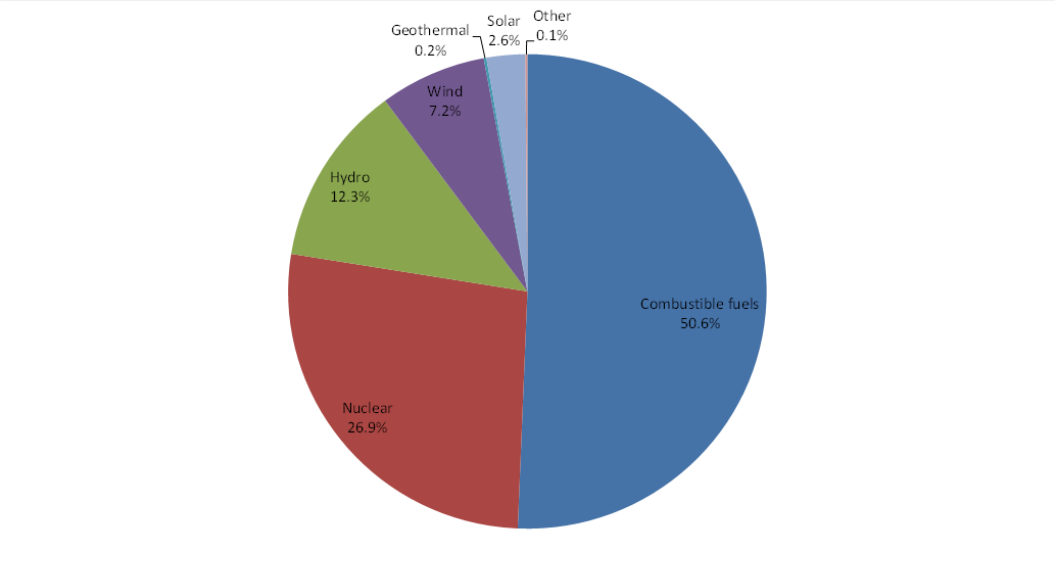
(Continued on the next page)

Box (continued)

In the context of electricity generation, EU policy encouraged the deployment of renewable energy sources (RES) ([3]). Renewable energy sources share the characteristic of low carbon emissions. Nuclear shares that characteristic. It is a technology that has been historically present in the EU countries energy mix, as each EU country can decide whether it wants to include it or not and due to the fact that public intervention in the energy sector was not limited in the past. An additional technology classified as low carbon is carbon capture and storage (CCS). Currently, fourteen EU member countries produce electricity from nuclear power. Nuclear and renewables are referred to as "low carbon technologies".

Nuclear and renewables play an important role in the EU electricity mix. In 2013 electricity generated from renewable energy sources contributed more than 20% of the EU-28's gross electricity consumption, while nuclear contributed around 26%. Among renewable energy sources, hydro generation accounted for 12.3% of the total, followed by solar and wind which, together, accounted for 9.4% of gross generation.

Graph 2: **Gross electricity generation in 2013, EU28**



Source: Eurostat, Energy Statistics

The development of renewable sources was also accompanied by public support measures. Where support constituted state aid, Member States had an obligation to design their schemes in line with the guidelines. Out of €10 billion granted for state aid to energy and environment between 2008 and 2012, €8 billion were granted to renewables and combined heat and power ([4]). Public support can take the form of state aid if it involves the use of state resources and under particular circumstances ([5]). State aid in the

([3]) Directive 2009/28/EC on the promotion of the use of energy from renewable sources is part of the 20-20-20 climate and energy package.

([4]) Competition Policy Brief, October 2014. These figures are not directly comparable to the total support figures in the chapter as total support includes also measures which do not fall under the definition of state aid.

([5]) That is, when state resources are allocated in such a way to grant a selective advantage to an undertaking or a group of undertakings which risks influencing trade across Member States. State aid is in principle not accepted in the EU, but it is tolerated when the intervention is necessary for a well-functioning economy to offset market failures and when it is instrumental to support objectives of common interest for the Union, like environmental policy. From 2008 notified state aid was assessed under the Guidelines on state aid for environmental protection 2008; since 2014 they are instead assessed under the updated Guidelines on State aid for environmental protection and energy 2014-2020 .Member States are required to notify DG Competition for any support scheme they intend to adopt (with some exceptions http://ec.europa.eu/competition/state_aid/overview/state_aid_procedures_en.html)

(Continued on the next page)

Box (continued)

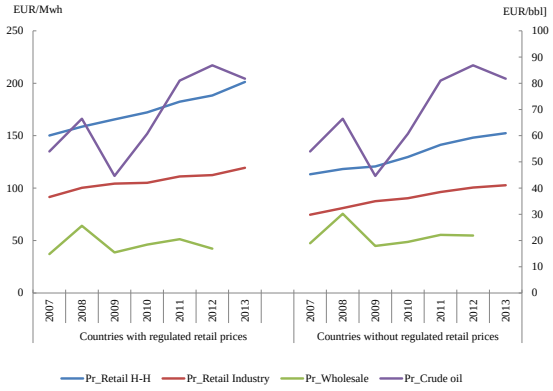
electricity production sector may be compatible with the functioning of the Union when it is perpetrated in order to pursue environmental objectives.

1.3.1. Electricity retail price evolution

In the recent period, electricity retail prices have experienced an increase ([5]) compared to wholesale prices. This divergence is the result of the increase of renewable capacity and of public support, which has been mostly financed by consumers through levies on electricity retail prices. The increasing trend can be observed for both household and industry retail price throughout the whole EU, even though there are considerable differences in the price level between the two types of consumers across groups of Member States.

In countries with regulated retail prices, the retail tariffs are higher than in countries without regulated prices. Whereas the two groups of countries showed different levels of retail prices already in 2007, through 2012 the increase in countries with regulated prices was higher than in countries without regulated prices([6]). In addition, the gap between the household and industry retail price level is higher for the former than for the latter.

Graph I.1.7: **Average domestic and industrial retail electricity price, wholesale price and crude oil price evolution 2007-2013**



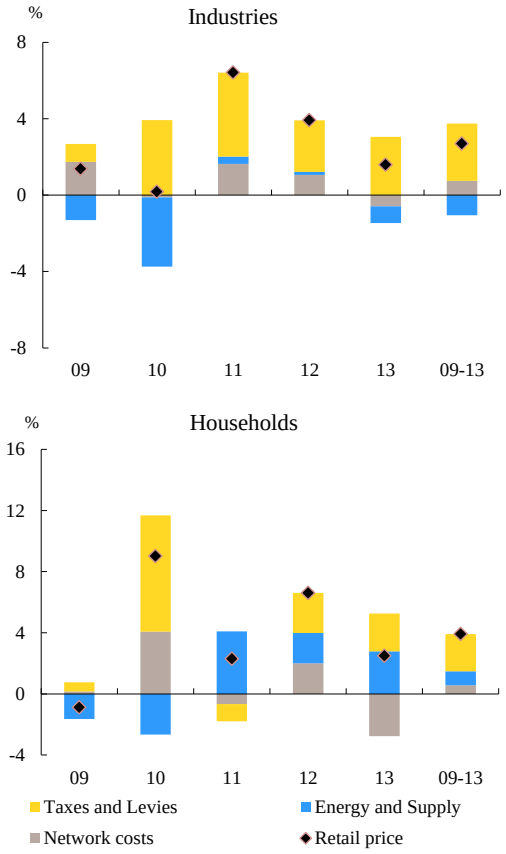
Note: The graph presents a weighted average of the retail prices. Prices are weighed by the share of electricity consumption.
The Consumption bands used were DC for Households (2500 kWh < Consumption < 5000 kWh) and IC for Industry (500 MWh < Consumption < 2000 MWh), wholesale prices are average spot prices from different European power exchanges and pools
Source: Eurostat

Taxes and levies ([7]) have been the main contributor to retail price increase for households and industrial consumers. Indeed, the increase of the taxes and levies component has been particularly pronounced and on average it contributed by more than 2% to the annual increases of retail prices in the 2009-2013 period ([8]). During the same period, a similar trend, but relatively lower, was observed for the network component. For both categories of consumers, the average annual contribution of this component to the retail prices increases was around 0.6%. In contrast, the contribution of the energy component to the retail price evolution, presented a diverging pattern between the two consumer categories for the period. In particular, the energy component put

([5]) European Commission (2014b).
([6]) Countries with regulated prices are Belgium, Bulgaria, Cyprus, Denmark, Estonia, Greece, Spain, France, Croatia, Hungary, Italy, Lithuania, Latvia, Malta, Poland, Portugal, Romania, Slovenia, United Kingdom. Countries without regulated prices are Austria, Germany, Finland, Ireland, Luxembourg, The Netherlands, Sweden, Slovakia.
([7]) Eurostat energy price data distinguish between energy and supply costs, network costs and taxes and levies. Hence, it is not possible to separate the impact on prices of levies and taxes respectively. Taxes generally refer to tax instruments such as VAT and excise duties, while specific levies support targeted energy or climate policies (eg renewable energy).
([8]) Anecdotal evidence suggests that most of the increase has been driven by levies and to a lesser extent by taxes. .

downward pressure on retail prices for households in first two years of the analysis, which then shifted to upward pressure. For industrial consumers, in contrast, it contributed to lowering retail price increases throughout the period. On average, this component decreased annually by 1.1% for industrial consumers, while for households it increased by 0.9%.

Graph I.1.8: **EU: retail price change and the contribution of the price components 2009-2013**

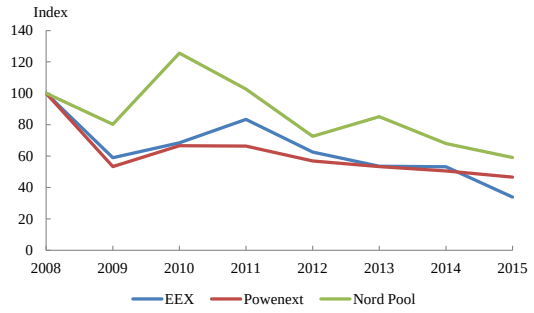


The graph presents the EU 24 weighted average compounded annual growth rate of the electricity price components of households (consumption band DC) and industrial consumers (consumption band IC). Prices are weighed by the share of electricity consumption.
Source: Eurostat and own calculations

1.3.2. Wholesale electricity and energy commodity prices evolution

Electricity wholesale prices have been declining after 2011. After the price spike in 2008, due to the influence of oil prices, wholesale electricity price on the German market (EEX) experienced a drop of 10% between 2009 and 2014. On the French market (Powernext) and the Nordic market (Nord Pool), prices decreased by 5% and 15% respectively, in the same period. The drop in wholesale prices is the result of many different factors, among which the evolution of energy commodity prices such as coal, gas and oil prices. They are, among other things, drivers of wholesale prices because they are the inputs for most of the conventional electricity production (see box I.1.2).

Graph I.1.9: **Electricity wholesale price**

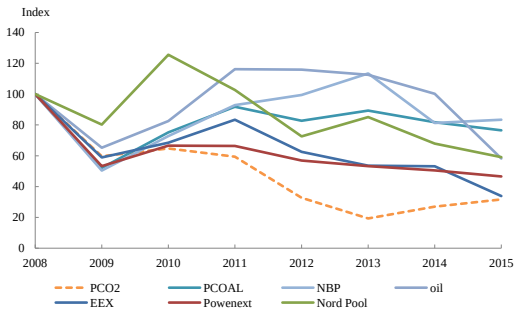


Source: Bloomberg, Platts

Coal, gas and oil prices followed similar decreasing paths starting from 2011. After a rebound in 2010, oil price started to decline from 2011, and experienced a sharp drop in 2014-2015. Gas and coal follow a trajectory which is similar in shape, even though the peak point for coal is 2011 while for gas it is 2013. In the period 2011-2015, gas prices dropped by 10%, while coal by 17% (Graph I.1.10).

By contrast, since 2009 the carbon price has decreased sharply. Carbon price plays a role on the wholesale electricity market in that it adjusts the relative costs of conventional and low carbon technologies and may incentivise investment in the latter. CO2 price followed a rapid and overall decreasing path: between 2008 and 2015, it dropped by 68% from 22.3EUR/tCO2 to 7.0EUR/tCO2. Such low levels have very little if not negligible effects on the relative costs of technologies and therefore can be assumed to have had a limited effect on short-term production choices. Fuel switching decisions for existing plants are mainly influenced by the relative costs of energy inputs (gas and coal). In the longer term, though, CO2 pricing is expected to play a strong role in the investment decision (see Box III.2.1).

Graph I.1.10: **Energy commodities and CO2 prices**



Source: Bloomberg, Platts

Other important factors contributing to lower wholesale prices are weak demand for electricity due to the economic crisis and the increasing renewable generation share. Investments in renewable generation, mostly driven by public support, and made in a situation of lower demand, contributed to lowering prices on the wholesale market. An econometric analysis of the drivers of wholesale prices confirms the upward impact of demand and commodity prices on prices, while an increasing share of renewable tend to lower prices (see box I.2.2).

Box I.1.2: **Electricity wholesale price drivers**

Understanding the long-term drivers of the electricity price is important to analyse the prospects of the electricity generation sector. Due to their long economic life, investments in the generation sector, which will determine the market characteristics of tomorrow, are made under the economic conditions of today. In this framework, it becomes crucial to understand the long term drivers of investment in the sector which, on functioning markets, are summarised by the wholesale price, which serves the purpose of signalling device.

There are two main factors that influence the development of electricity wholesale prices both over time and across Member States: the cost of the fuel used to produce electricity and the demand conditions. In order to take into account the double dimension of the wholesale electricity price series, the analysis is developed following a panel co-integration approach, which explores the relationship between the electricity wholesale price and a set of explanatory variables, as well as the existence of a long term relationship among them. The panel error correction model is specified as follows:

$$\Delta Y_{it} = a_{1i} + \lambda_1 EC_{It-1} + \sum_{k=0}^{q} \beta_{11ik} \Delta Y_{it-k} + \sum_{k=0}^{q} \beta_{12ik} \Delta G_{it-k} + u_{1it} \quad (1)$$

Where i stands for the markets (i=1-13) and t stands for the time, Δ represents the difference operator, EC is the lagged error correction term derived from the long-run relationship, αi,λi and βi are the coefficients, u is the error vector of the equations, D are dummy variables that capture seasonality effects, Y represents the dependent variable, G is the set of the explanatory variables and k is the number of lags, based on Schwarz information criterion.

The explanatory variables analysed are electricity demand, imports, exports, renewables and other external factors (Brent oil, Coal-ARA, Natural Gas-TTF and carbon prices). The variables are considered on a monthly basis and cover the period September 2007- July 2014 for 13 EU electricity markets (Austria, Belgium, Germany, Denmark, Greece, Spain, Finland, France, Italy, The Netherlands, Portugal, Sweden and United Kingdom). The dependent variable corresponds to day-ahead electricity prices.

Standard comparison techniques among different specifications of the model (including all explanatory variables or only selections of them) led to the choice of two specifications, which differ only in terms of the fuel included: crude oil or natural gas. Tests indicated that, for suspicion of severe multicollinearity, crude oil prices should not be included in the same regression with the natural gas prices and the coal prices ([1]).

Table 1: **Panel FMOLS and Dynamic OLS long-run estimates**

	MODEL 1		MODEL 2	
Variable	**Day-ahead prices**	**Day-ahead prices**	**Day-ahead prices**	**Day-ahead prices**
Carbon price	0.22***	0.22***	0.19***	0.19***
Natural gas price	0.42***	0.42***		
Share of renewables	-0.09***	-0.11***	-0.10***	-0.12***
Import	0.16***	0.16***	0.15***	0.18***
Electricity demand	0.23***	0.24**	0.44***	0.54***
Oil price			0.33***	0.39***
R2	65%	68%	51%	64%
Country Fixed Effects	YES	YES	YES	YES
Estimation Method	FMOLS	DOLS	FMOLS	DOLS

Note: *, **, *** indicate significance at 10%, 5% and 1% confidence level.
Source: European Commission

The model results show that the wholesale electricity price has been declining, at least partially because of structural changes in the European electricity sector. The increase in renewable technologies can be

([1]) For more information, please refer to Annex 2

(Continued on the next page)

Box (continued)

considered as a structural factor induced by policy action in the form of environmental policies. However, wholesale prices evolution has also been driven by cyclical factors. For example, an important factor that influences wholesale prices is the evolution of the electricity demand, which is mainly driven by general macroeconomic conditions and business cycles. Similarly, commodity prices have a different effect because they are linked to fluctuations in the world macroeconomic conditions.

Despite the fact that the electricity wholesale market today is sending a signal of structurally decreasing wholesale prices, the interpretation of the medium/long term effects is ambiguous. As expected, the model shows that in the long term, demand has a positive effect on electricity wholesale prices, whereas the relationship with the share of renewables is negative. The relationship between prices and coal, carbon, and gas prices identified by the model is positive. The positive relationship with energy commodity prices is due to the fact that today conventional technologies are price markers. With penetration of renewables, the moments when conventional technologies are price makers will be fewer, therefore reducing the scope for these expensive technologies to set the price. At the same time, though, demand for electricity will increase (see section 2.1.3), with a positive effect on prices. Moreover, the development of flexible solutions such as demand response will also impact price formation. Therefore, in the medium/long term, the overall effect of these two main structural drivers is ambiguous.

1.4. CONCLUDING REMARKS

Investment in electricity generation has been resilient to the crisis but its composition has changed. The expansion of renewable sources was much more pronounced than for conventional ones, a development which became more evident after 2009.

Public support has increased both for fossil fuel and renewable technologies, even though renewables accounted for most of the increment. Its composition across types of support remained relatively stable, with the major share going to support for electricity production, followed by support to demand, to investment, and to energy efficiency.

While electricity retail prices have risen in the recent period, wholesale price have decreased. The main factor contributing to rising retail prices are taxes and levies, but network costs have also increased. Rising levies reflect, among other things, the need for financing support schemes to renewable production. Wholesale prices have, in contrast, fallen due to lower demand for electricity as well as lower prices on fossil fuels and carbon. The increasing share of renewable generation in a situation of lower demand has also contributed to lower prices.

2. INVESTMENT IN ELECTRICITY: ASSESSING THE DRIVERS IN RENEWABLES AND CONVENTIONAL TECHNOLOGIES

Electricity is a sector in which investments are determined by macroeconomic conditions, but are also highly influenced by policies. Investments respond to macroeconomic conditions: general economic growth, demand evolution and financial conditions determine the general economic environment in which investment decisions are taken. Investments in the electricity sector are subject to a group of energy-specific factors which influence the decision to invest and the magnitude of the investment: the generation mix of the country, the wholesale prices, ([9]) as well as indicators about the supply side of the market such as the reserve margin and the capacity factor of the electricity system. In addition to this, policies can have a sizeable impact on investment decisions for example when they support some technology groups in order to achieve specific objectives.

This chapter explores both sets of investment drivers. Section 1 describes the different forms of support granted to renewable technologies and compares them to what is received by conventional ones. Section 2 develops an econometric model to understand the drivers of investment in conventional technologies. Section 3 concludes.

2.1. PUBLIC SUPPORT AND INVESTMENT

Public support for renewables has been justified by the need to promote low carbon technologies at early stages of development. These technologies would otherwise not be able to compete on the market due to higher costs. New renewable electricity production in Europe has been deployed mainly thanks to subsidies and priority of dispatch. Most renewable technologies remain too expensive and uncompetitive in relation to the market prices of today, even though certain are gradually becoming more mature: according to the IEA ([10]), increased investment in research, development and demonstration (RD&D) in emerging technologies, particularly ocean and enhanced geothermal, is needed to enhance competitiveness.

For this reason, renewable technologies have received the highest level of support per MWh. In the EU28, the average support per MWh for the 2008-2012 period was around 64 EUR/MWh, starting at 54 EUR/MWh in 2008 reaching 62 EUR/MWh in 2012 ([11]) with a peak of 70 EUR/MWh in 2010. The support level increased by 27% between 2008 and 2010, reflecting the implementation of the EU renewable energy policy as agreed in 2009 (Graph I.2.1). By contrast, support to conventional technologies has been much more limited, which can be explained by their level of maturity. Public support to these technologies has slightly increased between 2008 and 2012 ([12]).

In most Member States, support schemes and instruments have limited the risk exposure of producers, hence of investors. In 2012, seventeen Member States applied feed-in tariffs. This is an instrument which drastically reduces the risk for the producer as it provides a fixed remuneration for the renewable electricity produced. Feed-in-tariffs have proved to be very effective in promoting renewable electricity deployment, but this type of support also runs the risk of being very costly. Feed-in-premiums is another variant, which is a more market-based instrument that was used by nine Member States in 2012. It provides a premium in addition to the wholesale electricity price so that the producer is at least partly exposed to the price risk. Quota obligation systems were used in eight Member States. This implies the creation of a market for green certificates, which provides the generators with an additional remuneration source on top of the price received for the electricity produced from renewable

([9]) The profit streams of power plants do not depend only on day ahead markets (wholesale prices), but also on ancillary services and intraday and balancing markets. In general, day ahead markets are considered as the most important source of revenues of power plants.

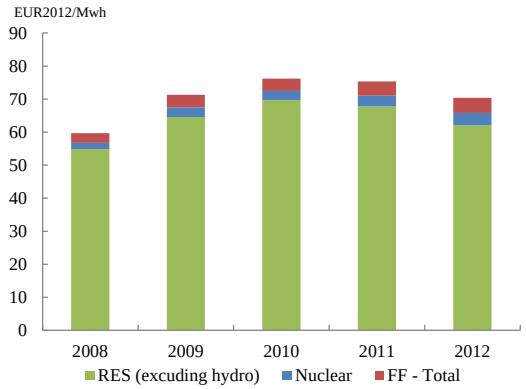
([10]) IEA (2014)

([11]) Estimates are potentially downward biased because of missing data.

([12]) It is important to notice that the levels of support to renewables and to conventional technologies presented in Graph I.2.1 are not directly comparable. As explained earlier, renewables are considered to be on an early stage of development compared to mature conventional technologies. This means that it should be taken into consideration that the present conventional technologies were developed in another market framework, where they also received some potentially comparable forms of support.

sources. Here, the producer is exposed to both the electricity and the certificate price risk. Finally, both investment grants and fiscal incentives were used by ten Member States respectively in 2012.

Graph I.2.1: **Support per electricity produced**

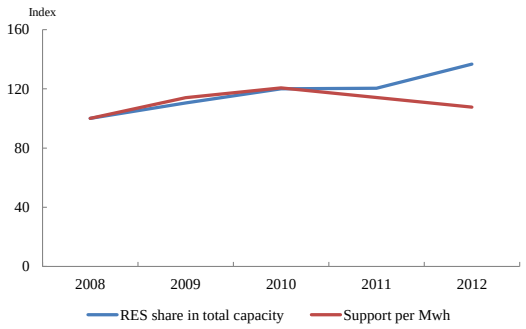


Hydro power was excluded from the analysis because it was mainly developed using support arrangements dating from before 2008. Its inclusion would underestimate the support level.
Source: Own calculations based on Eurostat, Energy Statistics and ECOFYS 2014

Support given to renewables decreased from 2010, due to the slowdown in economic activity caused by the economic crisis but also due to reforms of support systems aimed at reducing their costs. The crisis has reduced demand and deteriorated the general investment climate. The high cost of the renewable support system induced Member States to undertake reforms to make them more cost-efficient. This development was underpinned by the economic crisis, which forced Member States to enact reforms aiming to improve the efficiency of spending. The rising cost of support to renewables has been one contributing factor behind the emergence of tariff deficits in several EU Member States ([13]). A tariff deficit can be defined as a shortfall of revenues in the electricity system, which arises when the tariffs for the regulated component of the retail electricity price is set below the corresponding costs borne by the energy companies. Costs related to the support to renewables have been contributing to the tariff deficits in Spain, Portugal, France and Greece, and for temporary imbalances in the system in Germany and Italy. All these countries have undertaken reforms since 2012 to reduce and contain these costs and make them more market-oriented ([14]). In some cases (i.e. Spain, Portugal, Greece etc.) these reforms were imposed retroactively, which impacted the remuneration of past investments.

Reforms to support schemes have not yet translated into a slowdown of investment in renewables, (expressed as share in total capacity) according to current data.. The share of renewables in the EU has been on an increasing trend since 2008, whereas production support started its decrease in 2010. This apparently counter-intuitive fact can be explained by considering that, despite having been revised, support schemes appear to be still enough to sustain investment, probably thanks to the reduction in their costs through learning. An additional aspect is that investment responds with a lag to the change in support schemes, hence the effect the reduced support is not visible in 2012 data. Finally, it is important to stress that, whereas the data presented are European averages, the specific situation in Member States might differ substantially.

Graph I.2.2: **RES share and support evolution**



Source: Eurostat and ECOFYS 2014

2.2. MARKET DRIVEN INVESTMENTS

While renewables were developed heavily relying on public support, conventional ([15]) generation was affected by energy policy through the induced changing market conditions. EU policies are affecting the shape of

([13]) European Commission (2014a).

([14]) For this reason, more market oriented and cost-efficient support schemes were advocated. European Commission (2013).

([15]) In this chapter, the term conventional refers to nuclear, hydro and combustible fuels generation technologies.

the electricity market in different ways. Market liberalization introduced competition in the generation segment of the value chain; renewable obligations are reducing the residual demand that conventional technologies face; the EU emission trading scheme (ETS) is increasing the costs of production of conventional technologies in line with their carbon intensity.

2.2.1. The investment framework for conventional technologies

The factors that determine the investment decision in the power sector can be grouped into three main categories, i.e. macro-economic, competition and energy-specific. In order to understand their role, it is useful to provide a discussion of the assumptions to their contribution, which will be used to construct a model to analyse market driven investment in the recent past.

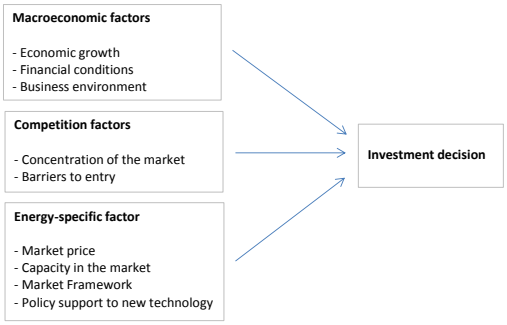
Macroeconomic conditions influence the decision to invest in electricity generation. They refer to economy-wide factors that influence the financial risk arising from the financing of investment as well as the policy objectives and institutional factors under the control of policy-makers (IEA, 2003). As such, the business environment, the cost of capital and access to finance are likely to impact the profitability of projects and ultimately the decision to invest. Moreover, given the role of electricity in the economy, economic growth is an important driver of electricity investments as it stimulates electricity consumption, hence the need to build additional generation capacity ([16]).

Another important factor which influences the attractiveness of the market is the competition intensity and potential barriers to entry. By nature, the electricity sector displays high sunk costs and needs large capital investments, which may provide an advantage to incumbents. In general, electricity markets are concentrated, which is a consequence of the characteristics of the sector, but may also give the opportunity to adopt a strategic behaviour to limit new entries in the market (e.g. excess capacity and pricing strategies).

Finally energy-specific conditions are likely to attract investors if profit prospects are high and uncertainty is low ([17]). Energy-specific conditions refer to those factors characterising the electricity system such as the wholesale price, ([18]) the reserve margin, the capacity factor and the generation mix. But they also include the economic conditions under which generators operate, i.e. the remuneration of their capacity or the price signal. Finally, the policy framework and the extent to which clean technologies are supported, influence the decision to invest in conventional technologies.

Graph I.2.3 summarises the main factors ([19]) influencing the investment decision in electricity markets.

Graph I.2.3: **Investment decision**



Source: European Commission

2.2.2. Hypotheses

The following macroeconomic factors are assumed to play a role in investment decision:

Macroeconomic factors

([16]) The long term causality with economic growth is bi-directional. This means that GDP growth has a positive effect on electricity investment and vice versa. See European Commission (2014c).

([17]) This section focuses on new investments and does not take account of replacement of capacities (see box 1.2.2). As mentioned by Ründiger and al (2014), a large amount of coal power fleet (130-170 GW) will reach the end of their production life.

([18]) The wholesale electricity price is considered as a reference price to signal investment (IEA, 2003). It is the basis for pricing electricity long and short-term contracts, even in the case where these contracts are traded over the counter (OTC) than in Spot markets.

([19]) Factors such as the public acceptance and availability of sites, which are important for nuclear and hydro plants, respectively, are not taken into account in the analysis due to data availability issues..

– **Higher electricity demand leads to higher investment in power generation**

Economic growth is normally accompanied by higher investments. ([20]) In electricity markets, demand is strongly correlated with economic growth, mainly because increased business activity implies higher electricity consumption ([21]). Hence it can be seen as a sign of an expanding market that businesses will want to exploit by increasing their investments in installed capacity. This indicates that demand is positively correlated with investment. In the future electricity demand is expected to be decoupled from economic growth, as a result of energy efficiency policies, so far it appears that it parallels economic growth.

– **Investments are negatively associated with interest rates**

Power plants are capital-intensive investments, for which the cost of financing plays a substantial part. Interest rates are used in the economic literature as an indication of the cost of capital: it is expected that higher interest rates have a negative effect on investments as they make investments more expensive.

– **A stable and transparent policy environment reduces investment risk and contributes positively to new investments**

Quality of regulation is an important factor in determining the investment environment. Good regulation that removes barriers to entry generally induces new entry and investment. Better regulation also induces investments when it is able to reduce the level of economic rents in a specific sector (see Box I.2.2). Because of the long time horizon, economies of scale and scope and the regulatory and political risks, investment will be especially sensitive to a country's institutional environment. It is expected that the better the policy environment in terms of commitment and transparency, the better the business environment and the more attractive the investment.

([20]) European Commission (2014c).
([21]) Demand could as well be interpreted as a technical factor when considering the load profiles it generates for the electricity system. Here, though, demand is interpreted as reflecting the general economic conditions of the country (economic growth vs. contraction) and this is why the variable is accounted for in the macroeconomic factors.

Box I.2.1: **Investment drivers: relevant literature**

The recent literature has mostly explored the drivers of renewable deployment. Neuhoff (2004) analyses the economic barriers to renewable deployment and proposes some policy responses to accelerate their pace of development. Eyraud and al. (2011) carry out an empirical analysis on the key driver of investments in green technologies. They suggest that green investment is boosted by economic growth, financial conditions, fuel prices as well as policy intervention (feed in tariffs, etc…). Vagliasindi (2012) explores the drivers of private investment in power in developing countries. Interestingly, the author finds a positive relationship between the switching toward investment in renewable and the policy framework (notably the introduction of the Kyoto Protocol). More recently, OECD (2014) explores the entry pattern in the generation segment, using firm level data. Entry decision is influenced by market structures such as competition, vertical integration and public ownership. In addition they find that support schemes influence the entry decision of firms in the renewable segment.

More specifically, the economic literature has explored the nature of the relationship between investment and the macroeconomic as well as the energy-specific variables.

The theory of optimal spot pricing posits that prices are able to convey the right investment signal if they are allowed to vary enough. In case of shortage of capacity, scarcity prices will increase, increasing average prices and producing profits that will attract new investments. In the opposite situation, when generation is excessive, scarcity prices do not materialise, decreasing average prices and preventing marginal generators to recover their capital costs, a dynamic that will drive them out of the market and reinstate the long-run equilibrium price level (Roques 2005).

Power market are often characterised by market dominance, partly because of the monopolistic structure of the industry in many countries before market liberalisation, and insufficient divestiture of the industry as part of the market reforms, and partly because of increased concentration in some markets through market restructuring by mergers and acquisitions after liberalisation (Hope 2005). In the presence of market dominance, a generating firm is able unilaterally to raise the market price of power by withholding generating capacity from the market until the price is high enough to cover its costs ("economic withholding") or by not offering its output to the market at any price (physical withholding") (Green 2004). The latter situation can be interpreted in terms of under-investment in generation capacity that the generator company pursues in order to maintaining prices higher than their efficient level. Literature suggests that, to ensure generation adequacy, policy makers should put more effort on enforcing competitive behaviour in the energy markets, and less on designing additional markets (see for example Léautier, 2013).

Among others, the financial conditions and quality of regulation and the institutional environment are important factors for investment in the power sector. The neoclassical theory of investment suggests that increasing the interest rate reduces investment by raising the cost of capital (Haavelmo, 1960; Jorgenson, 1967). In the context of electricity production, the capital intensive nature of investments in the sector makes the ability of raising capital or finance and its cost a major factor of the investment decision (Roques 2005).

Alesina and al (2005) investigate the relationship between product market regulation and investment in OECD countries. More specifically, they study the effects of regulatory reforms on investment in some sectors (transport, communication, utilities). They find that barriers to entry have a negative effect on investment whereas privatisation has no significant effect. Griffith and Harrison (2004) confirm this result by analysing the impact of product market reform on macroeconomic performance using as an intermediate variable the level of economic rents induced notably by regulation: they find a negative link between economic rents and investment.

The strand of literature which confirms the hypothesis that infrastructure investment are especially sensitive to a country's institutional environment is large: Williamson 1979; Levy and Spiller 1994; Spiller and Vogelsang 1993; and more recently Henisz 2002 finds that the ability of a nation to credibly commit to a given policy environment is an important component in explaining investment levels within that country. In

(Continued on the next page)

Box (continued)

electricity, Henisz and Zelner (2001) have found strong support for the hypothesis that political institutions that fail to constrain arbitrary behaviour by political actors dampen the incentive for infrastructure providers to deploy capital and, ceteris paribus, yield lower levels of per capita infrastructure investment.

Competition and Energy-specific factors

The following competition and energy-specific factors are analysed:

– **Electricity wholesale price as a signalling device for investment**

In a market, where the only commodity is energy (energy-only market) and there is no extra trade in capacity or other products, the primary income source for recovery of capital costs is the infra-marginal rent generated by the difference between the clearing price and the generators' marginal costs. According to the theory of spot pricing, the optimal capacity stock is such that the price resulting from scarcity is high enough to repay the capital costs of the marginal generators when demand exceeds supply ([22]). Therefore, when prices are high, the system signals the need for new investment; hence, it is expected that higher prices are positively correlated with investment.

– **Highly concentrated markets create significant barriers to entry that may impede new investment or expansion in electricity generation**

Concentrated markets are likely to suffer from abuse of market dominance, by which the incumbent firms enjoy the ability to unilaterally raise prices by providing a less-than-optimal capacity. It is therefore expected that the market concentration, as captured by HHI, CR3, etc. indexes, has a negative impact on investments.

– **Overcapacity reduces the motive for new investments**

The reserve margin indicator is defined as the ratio between total available generation and the maximum level of electricity demand, at the time at which that demand occurs ([23]). It can be interpreted as an indicator of overcapacity in the sense that a high value implies that there is a large amount of available generation to meet peak demand. On the other hand, if the indicator is low, it means that available capacity is small compared to maximum demand. Hence, it is expected that incentives to invest in market-oriented power plants are higher the lower the reserve margin.

– **Penetration of renewable technologies induce lower incentives for new investments in conventional power plants**

Renewable penetration reduces the residual demand for conventional generation, therefore reducing the size of the market they can bid on. Penetration of renewable was incentivised by support schemes, which are assumed to make investment in such technologies more attractive to investors (for example, because of more stable and higher returns) and hence to divert resources from conventional to low-carbon investment. It is expected that a higher renewable share decreases the scope for investment in conventional technologies because they increase their risk profile. In fact, the presence of renewables makes the revenue stream for conventional power plants very uncertain, whereas in their absence, conventional power plants will be operating a more predictable number of hours over the year.

– **Additional revenues from capacity mechanisms increase the incentives for new investments**

In energy only markets price caps may not allow power producers to receive the full amount of scarcity rents and to be able to recoup the fixed cost of their investment. The presence of capacity

([22]) Not all trade is performed through the spot market. For a discussion of the relationship among the different forms by which electricity is traded, refer to Box II.1.1.

([23]) Royal academy of engineering (2013). The reserve margin can be determined either for total available generation technologies or for total non-volatile (i.e. firmed) generation technologies. In this analysis, the latter calculation is used, as it is considered as a better indicator for identifying lack of key investments for ensuring security of supply.

mechanisms, which act as complementary source of revenues, helps to mitigate price uncertainty and volatility caused by weather conditions and intermittent generation by providing additional sources of revenues to producers than the energy only market ([24]). Capacity mechanisms can be seen as a factor that competes with spot prices for the role as a signal for investment needs; this is because if all the capacity is procured though capacity mechanisms, scarcity prices that reflect a structural lack of capacity will never appear on the spot market. For this reason, the analysis includes a dummy variable for the presence of capacity mechanisms to capture the effect on investment.

([24]) For a discussion on energy-only markets and capacity mechanism, see section 2.2.4 in chapter II.2.

Box I.2.2: **Methodology and data**

Methodology

The model assumes that electricity producers have two options: either to invest in new plants or not. The nature of investments in the power generation sector (long lead times between project and realisation, life time of power plants, etc.) is such that periods of investments are followed by periods of use of assets and absence of new additions, so that a high frequency of zero investments can be observed in many years and Member States ([1]). For this reason, the use of a Tobit model (Tobin, 1958) is needed in order to deal with the many zeros in the variable to be explained. ([2])

The model is based on a panel dataset, and builds on the work of Ishii and Yan, 2011. Its derivation is based on the hybrid of probit analysis and multiple regression, which gives an efficient method for estimating the relationship between an explanatory variable and truncated or censored dependent variable. It does this by estimating from a set of explanatory variables, the probability of a dependent variable being at or above (below) a limit. If the expected value of the dependent variable is above (below) the limit, then it is estimated. In this way, it has the advantage of using all the information that either a binary or OLS model separately would allow.

The regression model appears in Eq. (1):

$$Y_{it}^{*} = b_{it} * X_{it} + d_i + g_t + e_{it} \qquad (1)$$

where Y_{it} ([3]) represents the change in installed capacity of conventional power plants, nuclear and hydro plants, i stands for EU countries (i=1-28) and t for years (t=2005-2012), the d_i and the g_t represent cross-section and period specific effects and X_{it} includes a set of explanatory variables that capture the macroeconomic conditions (interest rates, institutional factors etc.) and the energy-specific conditions (wholesale price, reserve margin, electricity demand, renewable penetration, support schemes etc.).

Eq. (1) is a modified linear regression model in that it substitutes the term Y* for Y. This variation is necessary because the Tobit model contains censored or truncated data, and hence two separate equations are used. If the values of the dependent variable exceed the censoring value, which is zero in this case, then the traditional classical linear regression equation applies. However, if the dependent variable values are censored, e.g. an observed value of 0 occurs, the outcome is set to the limit value, 0. In other words, when Y* is 0, Y is set to 0, otherwise Y is calculated using Eq. (1), as follows:

$$Y_{it} = \begin{cases} Y_{it}^{*}, & if\ Y_{it}^{*} > 0 \\ 0, & if\ Y_{it}^{*} \leq 0 \end{cases} \qquad (2)$$

The negative coefficients of the explanatory variables of Eq. (2) are interpreted as reducing the size of new investments, while the positive coefficients will imply the reverse.

Data

In this model, investment is expressed in physical unit, i.e. additional capacity. This is explained by data limitations and is consistent with the empirical literature ([4]). Data were collected by various data sources,

([1]) For this reason, OLS is not an appropriate method to analyse investments in the power generation activity, because of the nature of the dependent variable. In other words, OLS estimations will provide inconsistent estimators.
([2]) For further information about the new additions in installed capacity of the conventional power plants per Member States and years see Table A1.1 in Annex 1.
([3]) The change in installed capacities is assumed to correspond to new capacities and does not include replacement of capacities.
([4]) The vast majority of the literature uses physical data when investigating the issue of investment in electricity markets, while acknowledging its limitations in terms of information on costs and quality. See European Commission (2014c).

(Continued on the next page)

Box (continued)

including EUROSTAT, ENTSO-E, OECD and BLOOMBERG. The macroeconomic and energy and climate related data were collected mainly by EUROSTAT and ENTSO-E, while the institutional and market indicators were sourced from the OECD and Bloomberg's database, respectively ([5]).

([5]) See Annex 2 for further information on the model specification and the variables included in the analysis.

2.2.3. Results

Table I.2.1 presents the estimation results of four distinct Tobit models based on the EU-28 Member States for the period 2005-2012. The difference between the four specification models is the choice of the variables included in the analysis. The consistency of the coefficients in terms of statistical significance and their size between the various specifications, indicate that the results are robust ([25]). In addition, in order to reflect the time effect on investment, the model includes lags. [(26)]

Electricity wholesale prices are a key driver of investment in power generation. The positive and statistically significant sign of the electricity wholesale price changes indicates that the observation of increasing prices stimulates investment in the near future. This finding confirms that investors in power plants react to high prices as a signal for higher expected returns, compared to other investment opportunities.

Increasing demand for electricity creates the need for new generating capacity. What matters for new investment in power generation is the growth in electricity demand in the course of time, rather than its level in comparison to other countries. Under an increasing demand pattern, investors are faced with less uncertainty on load factors for their plants, when and how often they will run, and the prices that could be achieved when they do run, as higher demand is associated with higher wholesale prices. Thus, it increases the expectations for higher profitability of the investment as the anticipation for the growth of the electricity demand is optimistic.

The cost of financing is of considerable importance to investments in power plants. As expected, the statistical significance and the negative sign of the coefficient of the interest rates imply that a rise in interest rates has a sizable negative effect on capital expenditures in power plants. In particular, the market interest rate is considered to be a key building block in the firm's user cost of capital, which, combined with the resulting stream of expected cash flows, constitute the primary determinants of whether and how much to invest.

Tight reserve margins trigger investment in power plants. The negative correlation between the reserve margin and the new additions in electricity installed capacity implies that, under conditions of high reserve margins investments are not attractive. The reason is that a high reserve margin is an indication of excess capacity, which means that the probability for a new investment to recover its capital plus a fair return on the assets is relatively limited.

Competitive markets reflect a good business environment and create incentives for investment in power generation. A competitive environment provides a steady and reliable business environment for new investments in electricity markets. The coefficient of the accumulated shares of the three larger electricity producers that was used as proxy of the degree of competition indicates that new additions in installed capacity are negatively correlated with concentrated market structures.

However, in order for competition to deliver its anticipated benefits, the market also requires governments to commit to policy and regulatory authorities to ensure transparency and optimal monitoring of the functioning of the electricity markets. Although in all specifications the proxy

([25]) The results of the Lagrange Multiplier test indicate that there is not any case of heteroskedasticity to any specifications.

([26]) The statistical significance of some variables with a lag, suggests that the current level of investment in installed capacity is influenced by past evolution of the explanatory variables or, in other words, that investment responds to changes of the explanatory variables with a lag. This is a sign of significant time effects on investments. The overall impact of a variable with more than one lag is calculated based on the sum of all the coefficients that are statistically significant.

Table I.2.1: **Results of the electricity investments drivers**

Variables		Dependent Variable: New Additions in Installed Capacity (1)			
		(1)	(2)	(3)	(4)
		Macroeconomic Factors			
Electricity Demand	Δ(eldem)	1.29***	1.29***	1.29***	1.29***
Interest Rates	Δ(iln)	1.17**	1.21**	1.19**	1.22**
Interest Rates	Δ(iln(-1))	-2.00***	-2.00***	-2.04***	-2.00***
Quality of Regulation			0.73		0.87
		Competition Factors			
Concentration Ratio of main Generators	Δ(cumshare)	-0.13***	-0.13***	-0.13***	-0.13***
		Energy-Specific Factors			
Electricity Wholesale Price (Spot)	Δ(spot)	-0.08	-0.08	-0.08	-0.08
Electricity Wholesale Price (Spot)	Δ(spot(-1))	0.09**	0.09**	0.09**	0.09**
RES share (% in total installed capacity)	Δ(ShRES)	-0.41*	-0.42*	-0.43*	-0.42*
Reserve Margin	Δ(resmargin)	11.72**	11.75**	11.85**	11.75**
Reserve Margin	Δ(resmargin(-1))	-12.85***	-12.97***	-13.01***	-13.04***
Dummy of Capacity Mechanisms				0.38	0.14
Constant		6.28***	5.15	6.32***	4.94
Country Fixed effects		YES	YES	YES	YES
Period Fixed effects		YES	YES	YES	YES
Log likelihood		-113	-113	-113	-113
Left-censored observations		20	20	20	20
Uncensored observations		50	50	50	50

*, **, *** indicates significance at 10%, 5%, and 1% confidence level.
(1) Installed capacity of power plant: nuclear, combustible fuels, biomass and hydro plants
Source: Commission Services

that was used in order to capture the quality of regulation had the expected sign, it was not statistically significant. ([27])

Higher penetration of renewables in total installed capacity is associated with lower investments in conventional generation technologies. The negative and statistically significant coefficient of the share of renewables in the total installed capacity implies that renewables replace over the years larger and larger part of the electricity supply curve.

The coefficient of the dummy variable for the presence of capacity markets was statistically insignificant though it presented the expected sign, The insignificance of this coefficient may be explained by the fact that most of the capacity mechanism incentives were introduced mainly over the recent years. This implies that other factors played a crucial role in the period of the analysis.

([27]) This effect might have been captured by the fixed effects and that is why the variable of quality of regulation is statistically insignificant.

2.3. CONCLUDING REMARKS

Investment in renewables was driven by public support, which was much higher than the support granted to nuclear and fossil fuels. Public support started decreasing in 2010 as a response to fiscal consolidation and to the increasingly heavy burden on public finances.

Market fundamentals were important drivers of investments in conventional technologies, mainly represented by the wholesale electricity price, financial conditions, demand and the level of competition on the market. The relevance of wholesale price for investment signals the remuneration investors can expect from the market. Similarly, the impact of financial conditions and demand captures the effects of the economic slowdown brought about by the recent economic crisis. Finally, the level of competition on the market explains the influence of the market structure.

In the future, in a world of competitive electricity technologies, the price signal as well as the macro-economic framework will matter for investors, hence the importance of market functioning and price formation.

Part II

Investment needs and price signal: perspectives

INTRODUCTION

Both the macro-economic framework and the energy market design play an important role in driving investments in electricity generation. This part looks at price formation in electricity wholesale markets and presents the main characteristics of the sector. It also assesses the challenges posed by the increasing penetration of low carbon technologies.

Chapter one describes the marginal pricing principle of wholesale electricity markets and discusses the different types of market design to keep the system reliable, i.e. energy-only market or capacity mechanism. It also presents the different market frameworks in place in Member States. Efforts to integrate energy markets in the EU are relatively recent but are showing signs of progress. Still the design of electricity markets varies considerably across the EU.

Chapter two discusses the investment needs to meet the decarbonisation policy agenda. Substantial investment will be required in the electricity sector both because of the sector's own need to reduce emissions, but also because demand is expected to rise from other sectors of the economy seeking to lower their emissions. The chapter also analyses the ongoing transformation of electricity markets induced by low carbon technologies. It discusses how the ongoing transformation contributes to changing the framework for investors, which points to the need to have the right market framework.

1. PRICE SIGNAL IN ELECTRICITY MARKETS AND MARKET FRAMEWORK IN MEMBER STATES

Prices are a key drivers of investment decisions as they influence potential remuneration to investors. In well-functioning competitive markets, high prices are expected to signal the need for additional investment. For investors, it is important that prices are above the long run marginal costs so that producers can recover their fixed costs.

This chapter describes the main characteristics of electricity markets. Section 1 focuses on the price formation mechanism in today's electricity markets. Section 2 looks at market features in Member States. Section 3 concludes.

1.1. PRICE SIGNAL TO INVESTORS

1.1.1. Remuneration in the electricity market

Expected remuneration is the key signal for investment because it represents the profitability of the undertaking. For electricity producers, remuneration can come from different sources, which also differ according to the market design (section 1.1.2). Generators can be remunerated for the energy they deliver from bilateral contracts and/or from the wholesale market; they can be remunerated from balancing services they provide; or, if such markets exist, they can get remuneration for the availability of production capacity that they offer (refer to Box II.1.1 for a more detailed description). All such products contribute to the final remuneration of generators.

The spot price on the wholesale market is used as a reference price for all other markets where energy is traded, forward markets or bilateral agreements. In a market which is not distorted by external interventions, the variability of the spot price plays a role in signalling the need of investment in new resources. Where interventions are in place which protect some technologies from exposure to prices (for example remuneration from pre-determined schemes rather than from the market price), distortions might appear that weaken the price signal.

In general, the spot price on the wholesale market corresponds to the price set on the day-ahead market. Generators bid on the day-ahead market and then refine their positions during intraday trade. Both markets are linked and participants get revenues from both intraday and day-ahead markets (see box II.1.1).

1.1.2. Marginal cost pricing

Electricity prices on the spot market are based on the bid of the marginal unit ([28]). The typical electricity supply curve is a piecewise linear function. Each step represents a type of generation source, with the quantity of electricity that can be supplied at the quoted price. Cheaper generation is dispatched first in the market, so that the supply function is upward sloping: demand is first met with lower cost energy, and higher cost generation is called in progressively with increased quantity. The equilibrium price (the 'spot price') is the price of the marginal generation source needed to meet demand. Simplifying, it can be said that this is the price that all generators receive. The supply curve obtained by aggregation of the different bids is also known as *merit-order curve*. All bids below the clearing price are *in the merit* whereas all bids above the clearing price are *out of merit*.

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([28]) This is achieved mostly within day-ahead markets as currently other markets such as intra-day markets are not sufficiently developed.

Box II.1.1: **Wholesale electricity markets**

1. Description of markets

Electricity wholesale markets are generally split into bilateral contracts, where transactions are contracted bilaterally outside the market, and organised exchanges, where quotes from buyers and sellers are aggregated to form a unique market price. In addition, three specific products can be identified which constitute the electricity system:

- Scheduled energy is the actual power produced and delivered to customers. It can be further decomposed into long-term electricity procurement (future or forward contracts), shorter-term electricity procurement (spot contracts), and electricity required to balance instantaneous deviations (balancing);
- Ancillary services are technical services required to keep the electrical system stable;
- Generation capacity refers to the procurement of the physical ability to produce electricity for long-term adequacy of the system.

For each product, there exists a (sub)market characterised by specific pricing mechanisms and dynamics. In this report, the focus is made on the sale of scheduled energy on wholesale markets.

The core of the wholesale markets, where market forces interact to determine the electricity price, is the market for spot contracts. Spot prices set the reference for all other transactions; hence the functioning of the spot market is the benchmark for the whole sector. Whereas for financial assets and most commodities the term 'spot' refers to a market for immediate delivery, for electricity this would not be possible because the system operator needs advance notice to verify that the schedule is feasible for the system and to ensure its stability. In the electricity context, then, spot markets refer to contracts for short term delivery.

Spot markets can be thought of comprising three (main) sub-markets: (i) day-ahead (ii) intraday and (iii) balancing markets.

(i) In day-ahead markets, generators ([1]) and buyers trade electricity 24 hours ahead of physical delivery. These are auction markets, where market actors enter their bids that are then matched by the system operator. Bids specify quantities to be sold or bought and the price that the actors are willing to accept/pay for that quantity. The market calculates an equilibrium price that balances demand with supply (see section1.1). Market actors commit to the positions they trade in this market based on their forecast of electricity need. In practice, these forecasts are never 100% accurate, and imbalances between traded positions and actual energy consumption and production occur.

(ii) The intraday market can be used to adjust the contracted position in the day-ahead market (without changing it) whenever there is an unpredicted imbalance that interferes with the positions traded on the day-ahead market (for example a plant outage, greater renewable production due to exceptional weather conditions, demand fluctuations). Intraday markets (also known as adjustment/hour-ahead markets) are usually organized by continuous trading: as soon as

([1]) In reality generators are not the only actors offering electricity on the market. Traders enter such positions as well, even though the ultimate provider of power is a physical generation plant. For simplicity, this analysis will refer simply to 'generators' when talking about market actors offering power on the market.

(Continued on the next page)

Box (continued)

two orders are compatible, they are matched and executed. Trade is allowed very close to delivery, with time intervals varying from 60 to 10 minutes.

(iii) The balancing market is used to cover imbalances left after markets have closed. Balancing starts after markets have closed (gate closure) when the transmission system operator (TSO) acts to ensure that demand is equal to supply, in and near real time ([2]). Deviations need to be corrected in a matter of minutes or even second to ensure physical delivery and to ensure that the system is in balance. Participants in the balancing market submit bids that specify a price to increase generation (or decrease consumption) for a specific volume immediately. In order to cover this capacity, the power system requires units that are able to provide electricity at any time and on short boosting times (mid-merit and peaking units).

Day-ahead and intraday markets are 'economic markets' in the sense that they operate economic dispatch: they determine the short-term optimal output of a number of electricity generation facilities, to meet the system load, at the lowest possible cost. The nature of the balancing market, instead, is more technical. This difference is also reflected in the way they are operated: day-ahead and intraday markets are managed by power market operators, whereas the balancing market falls under the TSO's responsibility. Day-ahead, intraday and balancing markets serve different purposes, and are complementary to each other.

Prices on the spot market can be very volatile. To minimise the risks inherent to short term trade, some wholesale markets offer also the possibility to trade forward or future contracts. Market players can sign sale/purchase contracts for the supply of electricity over weeks, months, quarterly periods or years (usually between 1 to 4 years), at a price negotiated on the contract date. Futures cover standardised products in order to facilitate their trade (for example, supply of base electricity MW, i.e. during all hours of the month, or at peak times, i.e. from 8.00 a.m. until 8.00 pm from Monday to Friday) while forwards are ad-hoc contracts negotiated bilaterally between the interested parties. In a well-functioning market, future prices are less volatile than spot prices and roughly correspond to an average of the spot prices anticipated for the period in question; hence they are mainly hedging tools and are used to define pricing for the customer. Future contracts can be used as hedging instruments against price volatility and make electricity trade smoother: when suppliers sign contracts for physical delivery of electricity with a customer, they will generally hedge the price risk by purchasing the required future products. In addition, vertical integration can be used as a form of hedging against spot price risk.

Participation on the spot market can be mandatory, in which case the exchange is said to have a "power pool" structure, or voluntary, in which case it is said to have a "power-exchange" structure. Power pools are centralized markets, usually set up by government initiative after market liberalization to facilitate competition between generators. In the power pool design, participation is mandatory: generators and demand submit bids, from which the merit order is derived, and no trade is allowed outside the pool. The demand side is represented by a "Single Buyer" which buys all electricity from the generation sector based on a top-down estimation of demand. Hence, the market mechanism is a one-sided auction, where bids come from the supply side only. Power-exchanges are centralized market normally launched as a private initiative by generators, distributors and traders. In the power-exchange design, participation is voluntary, although there are some exceptions. This means that bilateral contracts are allowed in parallel to market transactions. Participants in the market are generators, distribution companies, traders and large consumers. Both the supply side (generators and

([2]) See ENTSO- E website.

(Continued on the next page)

Box (continued)

traders) and the demand side (distributors, traders and large consumers) submit bids for power. Hence, the market mechanism is a two-sided auction, where demand is aggregated on the basis of a bottom-up approach.

2. Prices on the intraday and day-ahead markets

In general, "spot price" corresponds to the price set in the day-ahead market. Generators bid on the day-ahead market and then refine their positions during intraday trade. In properly functioning markets, the two prices are linked and interact in the profit maximization strategy of generators. The purpose of the intraday market is to correct the estimations of the past to meet actual market conditions. Happening closer to delivery when market conditions (both demand and supply components) are better known, it is the intraday market that provides the best price signal to control production. In reality, though, most of the trade on markets happens in the day-ahead market. This is explained by the fact that markets prices on the intraday and day-ahead markets are intimately related by what is called the two-settlement system.

In properly implemented two-settlement systems, generators will behave as if they were selling all their output on the intraday market. To understand why, consider the following example: a generator commits to provide quantity Q1 at price P1 on the day-ahead market. Hence, by trading on the day-ahead market the generator commits to the position {Q1; P1}, for which it receives a payment of $\pi 1 = Q1 \times P1$. The important characteristic of $\pi 1$ is that the generator commits to it through trade on the day-ahead market. On the intraday market, the generator can deliver quantity Q0, which can differ from Q1. This imbalance will be traded on the intraday market at the intraday price P0. If there is no difference between the quantity traded on the day head market, Q1, and the quantity delivered on the intraday market, Q0, the generator is treated as if it had delivered the amount promised in the day-ahead market but purchased that amount from the intraday market to cover its promised delivery. The generator is paid:

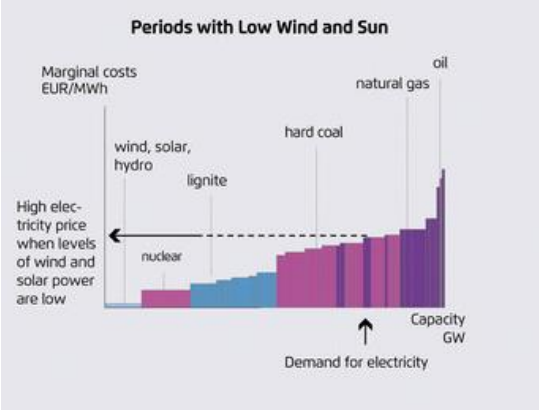
$$\Pi = - (Q1 \times P0) + (Q1 \times P1) + (Q0 \times P0)$$

Where the first bracket refers to the purchase on the intraday market, the second bracket is the trade on the day-ahead market and the third bracket is actually zero, because there is no difference between Q1 and Q0. If Q0 >Q1, the generator will be paid for the difference.

Generators in fact have the same incentives by trading on the day-ahead market only or by submitting bids on the intraday market as well. In practice, it can be seen as a "sunk cost", when P0 > P1, because in this case the generator delivers on the intraday market only and simply pays the settlement corresponding to the position on the day-ahead market; or it can be seen as an "assured revenue", when P0 < P1. In this case, in fact, the generator is paid what contracted in the day-ahead market, despite the lower price on the intraday market. For this reason, the day-ahead market price manages to convey the right price signal to generators.

Graph II.1.1 shows a generic merit-order curve with six generation technologies: renewables, nuclear, lignite, hard coal, natural gas and oil. They are ordered left to right on the basis of their marginal costs from the cheapest to the most expensive. Demand intersects the merit-order curve at a point in the supply served by hard coal plants. The price is set by the bid of the last hard coal plant in the merit. This means that all other generation units with lower bids earn an infra-marginal rent equal to the difference between their bid and the bid of the hard coal plant (that is the spot price). Under the assumption of perfect competition in the market, bids represent the marginal costs of the plant to supply energy.

Graph II.1.1: **A generic merit-order curve and the effect of increased low marginal cost technologies**



Source: AGORA Energiewende

With such a mechanism, a well-functioning and competitive power market produces electricity at the lowest cost for each hour of the day. The equilibrium price reflects both: (i) the cost of producing one kWh of electricity from the most expensive source needed to meet the demand; and (ii) the price that consumers are willing to pay for the final kWh required to meet the demand.

1.1.3. Economic approach to the equilibrium of the electricity system

The characteristics of electricity production make the reality of electricity markets complex. First, storability of electricity is currently limited, which means that the electricity produced is consumed instantaneously. Any oversupply of electricity would be lost at the moment it is produced. Second, demand is still rather inelastic (although important improvements in demand response are foreseen in the near future), and prices can reach very high levels within a short period if demand is not met. By contrast, when demand is low, a large part of capacity remains idle, hence not remunerated by the market. The task of ensuring a sufficient level of supply to meet demand at all moments is a challenging one, not only for the daily dispatching, but also in a long term perspective. The electricity system needs to be able to invest in capacity ahead of demand developments in order to make sure that enough production capacity is available when needed.

For this reason, an important aspect of market design is the need to keep the system reliable. Different market designs exist, which can be classified under two main categories based on the products traded: in an *energy only* market, the only product is the power produced, whereas in the presence of a *capacity* market, the availability of power plants is an additional product.

In an ***energy-only market***, the signal for investment relies on high prices that materialise in moments of excess demand (these are called *scarcity prices* and moments of excess demand are *scarcity scenarios*): whenever there is a scarcity scenario, prices are allowed to rise so that generators start earning 'scarcity rents' that are high enough to cover their fixed costs of capital and induce new investment/new entry in the market. The problem with this approach is that it may lead to high price volatility, which increases the investment risk associated to the electricity market and the uncertainty – especially for peaking plants, but also for variables renewable plants([29]) – to recuperate their investments; the possibility for prices to reach very high levels may also be used strategically by market players to abuse market power. For these and other reasons, wholesale electricity prices are usually capped. Finally, potentially variable and high prices might not be desirable if they expose consumers, both households and industry, to unsustainable high prices; nonetheless, long term contracts could be devised for customers not willing to be exposed to price volatility.

Alternatively, the market can be designed as an ***energy market complemented by a capacity mechanism***. Markets designed in this way involve the trade of two products: scheduled energy (and services) and the ability to deliver power at some point in time (that is: "generation capacity"). For the trade of electricity, these markets make use of the same wholesale market design as energy-only markets. The difference is that they complement it with a capacity mechanism. Capacity mechanisms are tools to remunerate capacity for the simple fact of being available if needed. They can be price-based, hence setting a price for capacity availability; or they can be quantity based, in which case the required volume is determined at the outset and it is left to the market to set the appropriate price. All the relative costs associated

([29]) As high prices will tend to appear when generation from variable renewable is low.

Table II.1.1: **Electricity Regional Initiatives**

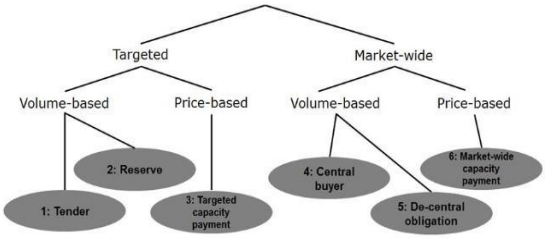
Region	Countries in the region
Northern region	Denmark, Finland, Germany, Poland, Sweden, Norway
Baltic region	Estonia, Latvia, Lithuania
Central Eastern region	Austria, Czech Republic, Germany, Hungary, Poland, Slovakia, Slovenia
Central South region	Austria, France, Germany, Greece, Italy, Slovenia
Central West region	Belgium, France, Germany, Luxembourg, Netherlands
South West region	France, Portugal, Spain
France, United Kingdom and Ireland region	France, Ireland, United Kingdom

Source: European Commission

with capacity mechanisms should be borne by consumers.

The Commission distinguishes six categories of capacity mechanisms ([30]) which are split between targeted and market-wide mechanisms. Targeted mechanisms focus on the additional capacity expected on top of what the market will provide. Market-wide mechanisms provide support to the majority of capacity providers in the market. Both targeted and market wide mechanisms can be further split between volume-based and price-based intervention. Volume-based mechanisms are: tender, reserve, central buyer, de-centralised obligation; while price based mechanisms are: capacity payment and targeted capacity payment.

Graph II.1.2: **Taxonomy of capacity mechanisms**



Source: European Commission

1.2. MARKET FRAMEWORKS IN MEMBER STATES

Historically energy policy in the Member States was managed at national level, whereas only relatively recently efforts have been made to steer the architecture of the different energy systems towards an integrated design.

1.2.1. EU integration

Market integration has improved thanks to the Electricity Regional Initiatives (ERI), launched in 2006, aimed to create seven regional electricity markets in Europe, as an interim step towards the Internal Electricity Market. Each region brings together regulators, companies, Member States, the European Commission and other interested parties to focus on developing and implementing solutions to improve the way in which regional energy markets develop. An overall monitoring process at EU level ensures that progress towards a single EU market is not hampered, and that there is convergence and coherence across the regions.

A similar harmonisation effort started in 2014 with respect to support schemes. Investment in renewables was achieved mainly through support schemes that were national in scope (chapter I.2). In 2014 the new Guidelines for state aid for environmental protection and energy ([31]) set the path towards harmonisation of support schemes across Europe.

Market coupling has also improved. On 24 February 2015, for the first time, day-ahead power markets were linked from Finland to Portugal and Slovenia, accounting for about 2,800 TWh of yearly consumption and encompassing nineteen power systems. The EU has also agreed to achieve an interconnection level of at least 10 % of their installed electricity production capacity for all Member States by 2020. This target has been proposed to be extended to 15% by 2030. ([32]) In addition, regional cooperation is being pursued, for

([30]) For further information, refer to the State Aid sector inquiry into capacity mechanisms and European Commission (2013c)

([31]) European Commission (2014d)
([32]) European Commission (2014e)

Table II.1.2: **Electricity market characteristics at Member State-level**

Country	Power Exchange	Power Pool	Energy only Market	Capacity Mechanism	Strategic Reserve
Austria	x		x		
Belgium	x				x
Bulgaria			x		
Croatia			na	na	na
Cyprus			na	na	na
Czech Republic	x		x		
Denmark	x				x
Estonia	x		x		
Finland	x				x
France	x			x	
Germany	x				x
Greece		x		x	
Hungary	x			x	
Ireland		x		x	
Italy	x			x	
Latvia	x		x		
Lithuania	x		x		
Luxembourg			na	na	na
Malta			na	na	na
Netherlands	x		x		
Poland	x		x		
Portugal		x		x	
Romania	x		x		
Slovakia	x		x		
Slovenia	x		x		
Spain		x		x	
Sweden	x				x
United Kingdom	x			x	

A Member State is reported as having a capacity mechanism or a strategic reserve whether they are "active", "proposed" or "under consideration".
Source: ACER 2013

instance, to reinforce cross-border network infrastructures such as in the North Sea area (through the North Seas Countries' Offshore Grid Initiative), in the Baltic region (through the Baltic Energy Market Interconnection Plan - BEMIP) and in the Pentalateral Energy Forum between Germany, Belgium, France, Luxembourg, the Netherlands and Austria.

1.2.2. Member States

In terms of market design, most Member States employ a power exchange ([33]), where trade through the market is optional (see table III.1.2)**.** Greece, Ireland, Portugal and Spain have adopted a power pool, where all transactions must go through the market. In Bulgaria, Cyprus, and Luxemburg there is no wholesale market and transactions are either agreed on a bilateral basis (over the counter) or are managed by the central authority.

Member States differ also in the choice of reliance on an energy-only or a capacity market. Currently, most of the active capacity mechanisms aim to ensure the firmness and adequacy of the overall capacity of the market to meet demand. Some Member States purely rely on an energy-only market (Austria, Bulgaria, Czech Republic, Estonia, Latvia, Lithuania, Netherlands, Romania, Slovakia and Slovenia) whereas others made the choice to accompany the energy-only market by some form of capacity mechanism (see section 1.1.3).

Different forms of capacity mechanisms have been implemented in several European countries while others are discussing their implementation. Belgium, Sweden, Finland, and

([33]) For more information on the architecture of spot markets, including the difference between power exchange and power pool refer to Box II.1.1

Germany operate strategic reserves ([34]). Ireland, Italy, Portugal and Spain practice capacity payments. France plans to implement a capacity obligation scheme supported by certification of capacity. Denmark plans to implement a strategic reserve. Greece has a capacity obligations scheme since 2005 ([35]). The United Kingdom has opted for a centralized, market wide capacity auction. Other Member States are supporting new investments through tenders for new capacity. Various Member States are considering new capacity mechanisms. ([36]).

Support schemes are evolving. Even though a big part of investment in renewables is driven by support schemes, evolution towards market-based allocations and/or pricing can be observed in some Member States. To tackle the problem of revenue uncertainty in electricity generation and a consequent difficulty in getting private sector investment, the United Kingdom passed the Energy Act 2013 to implement Electricity Market Reform (EMR) which implements legally-binding Contracts for Difference. Through a Contract for Difference the electricity generator is paid the difference between the price reflecting the cost of investing in a particular low carbon technology – and the 'reference price'– a measure of the average market price for electricity in the British market. In addition, the scope of the schemes is changing from renewable-targeted (a type of action which is more technology-specific) to low-carbon (a requirement which is instead emission reduction-specific). In Spain, feed-in tariffs and feed-in premia were replaced by investment support schemes ([37]) based on which renewable producers must submit offers to the market operator. If the revenues collected from the market are not sufficient to cover their costs plus a fair return, then a subsidy will be given in €/MW on a yearly basis in order to ensure that the predetermined level of profitability ([38]) will be achieved.

The presence or not of a price-cap on the wholesale market is one additional source of heterogeneity across Member States. For instance, price caps have been set in the French and German power exchange at +/-3000 EUR/MWh, which means that the price cannot exceed these limits. Nord Pool Spot has a range of -200 EUR/MWh to +2,000 EUR/MWh ([39]), ([40]). The Irish power exchange SEM has a price cap of 1 000 EUR/MWh. In the Iberian power market OMEL bids are allowed between 0 and 180 EUR/MWh ([41]). Possibly, also other Member States implement price caps.

1.3. CONCLUDING REMARKS

Power price formation is based on the bid of the marginal unit required to meet demand, which in a competitive market will correspond to its marginal cost. For each technology, the difference between the market price and its costs, i.e. the inframarginal-rent, allows investors to breakeven. Some additional revenue can also be realised on the balancing market.

T**he role of the price is different across market frameworks**. In energy only markets, the stability of the system in terms of investments in capacity is achieved through electricity prices. When demand is in excess, prices increase to signal scarcity on the market. The high scarcity price enables the generators to cover their fixed capital costs and provide an incentive to invest so that the capacity will be able to meet market demand. In other market frameworks, the energy market is complemented by a capacity mechanism to incentivise investment to make the capacity available to meet the demand (often targeting a long term reliability standards).

([34]) See the classification of capacity mechanisms in section II.1.1.3. The impact of these various forms of capacity mechanisms is different whether they are targeted or wide market-based..
([35]) In parallel, a transitory capacity payment scheme was put in place from 2006 till 2014, to facilitate market participants conclude capacity available contracts due to the significant market share of the incumbent.
([36]) The Commission has launched a state aid sector inquiry into capacity mechanisms in 2015 to provide a clearer picture of the different initiatives in this area. The inquiry will identify design features that may distort competition between capacity providers and distort cross-border trade; and in particular will examine whether capacity mechanisms ensure sufficient electricity supply without distorting competition or trade in the EU's Single Market.
([37]) Real Decreto-ley 9/2013
([38]) Set at 7.3% pre-tax. The level of profitability is set based on the yield of the Spanish ten year bond plus 300 basis points and it is revised every six years
([39]) EMCC (2009)
([40]) ECF (2012)
([41]) European Commission (2013a)

Although EU wholesale markets have been progressively harmonised, market framework still differ across Member States in terms of electricity traded via various markets (day-ahead, intra-day, balancing markets), implementation of capacity mechanisms and other forms of price regulation, e.g. price caps.

2. THE TRANSITION TO LOW CARBON ECONOMIES AND INVESTMENT NEEDS

The decarbonisation agenda of the European Union requires large investments to take place in the next future. At the same time, the liberalisation of the electricity market has enhanced the role of spot markets in providing the signal for investment. However, the penetration of low carbon technologies is challenging the functioning of the market and changing the investment landscape.

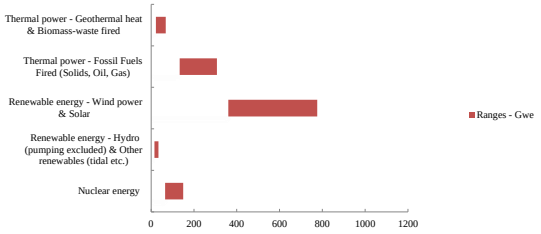
The objective of this chapter is to reflect on the evolution of key features for investment in electricity markets. Section 1 assesses investment needs in electricity generation; Section 2 describes the ongoing transformation of electricity markets and the potential impact on power prices. Section 3 concludes.

2.1. THE CASE FOR INVESTMENTS IN ELECTRICITY MARKETS

The transition to a low-carbon and energy-secure economy requires mobilisation of significant investments in Europe. The Impact Assessment of the energy efficiency review and its contribution to energy security and the 2030 Framework for climate and energy policy estimated the investment needs related both to the achievement of the 2030 targets and the modernization and transformation of the energy system in the EU Member States ([42]). These projections show that EUR 90 billion of investments are needed annually up to 2030 in the power sector, of which EUR 50 billion for energy generation and EUR 40 billion related to power grids. This is driven by the need to modernise the EU's ageing energy infrastructure (for generation as well as transmission and distribution), as a response to security of supply issues, and due to energy and climate policy ambitions.

Significant investments in renewable power capacity will be needed up to 2030 under decarbonisation. Graph II.2.1 presents the ranges of net capacity investment in the period 2011-2030 for the different scenarios of the Impact Assessment of the energy efficiency review and its contribution to energy security and the 2030 Framework for climate and energy policy. These investment numbers include lifetime extensions of existing plants, refurbishments and replacement investments on existing sites.

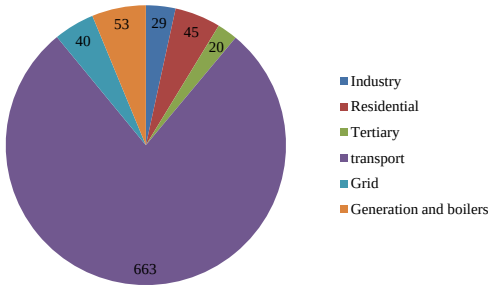
Graph II.2.1: **Ranges for EU28 - Net Power Capacity Investment (in GWe - aggregate 2011-2030)**



Source: European Commission (2014 f)

In addition to the investment needs for the power sector, substantial investments are also required in other sectors of the economy, i.e. transport (energy efficiency, electrification), buildings (energy efficiency, innovation) and industry (energy efficiency, innovation). Total investment needs are estimated at EUR 850 billion annually up to 2030.

Graph II.2.2: **Annual Investment Expenditures in billion of euro - 2010 (2011-2030)**



Source: European Commission (2014 f)

Decarbonisation of the rest of the economy is expected to lead to higher demand for the generation electricity sector. Electricity consumption is still largely driven by GDP growth although energy efficiency improvements have contributed to decouple energy performance from economic growth. Electricity consumption decreased starting in 2008 due to the impact of the economic crisis and the subsequent sluggish

([42]) European Commission (2014f)

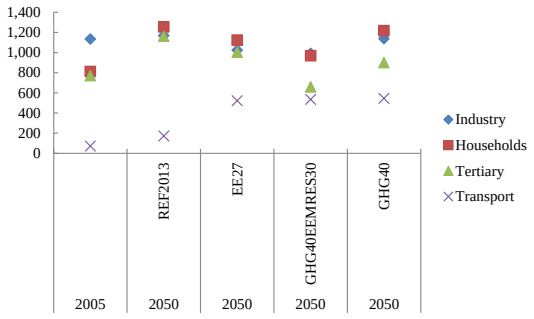
Table II.2.1: **Electricity cost structure**

(EUR 2008 per MWh)	Reference Scenario		High RES penetration*		High nuclear penetration **	
	2030	2050	2030	2050	2030	2050
Fixed and Capital costs	58%	53%	69%	80%	65%	67%
Variable and fuel costs	42%	47%	31%	20%	35%	33%
			scenario 4		scenario5	

* refers to scenario 2 of the Impact Assessment; ** refers to scenario 5 of the Impact Assessment.
Source: Own calculations based on Impact Assessment accompanying the document Energy Roadmap 2050, part 2, Table 31.

recovery, as well as to energy intensity improvements. At the end of 2012, total electricity consumption was still 2.3% lower than in 2008, whereas analysts were expecting an average annual growth rate of about 2% ([43]) at the time. In the future, the energy efficiency improvement in the rest of the economy is expected to increase the demand for electricity. According to the Energy Roadmap 2050 ([44]), the electricity share in the final energy consumption is expected to double compared to 2005 in the decarbonisation scenarios ([45]) reaching 36% - 39% of final energy demand in 2050. This reflects the increasing role played by electricity in decarbonising final demand sectors such as heating and services and in particular transport.

Graph II.2.3: **EU28 - Electricity consumption (in TWh) - Final electricity demand in TWh***



*European Commission (2014)
Source: European Commission

Electricity demand in the transport sector in 2050 increases by almost a factor eight compared to 2005 under the different scenarios of the Impact Assessment of the energy efficiency review and its contribution to energy security and the 2030 Framework for climate and energy policy. This is mainly due to the electrification of road transport, in particular private cars. About 80% of private passenger transport activity is foreseen to be carried out with electrified (plug-in or pure electric) vehicles by 2050. Compared to transport, the electricity demand of households and the tertiary sector is expanding more modestly by 2050, yet markedly, mainly driven by the electrification of heating and cooling. This new usage of electricity overcomes the improvements achieved by 2050 in energy efficiency of appliances as well as the increased thermal integrity in the residential and service sectors and more rational use of energy in all sectors. By contrast, industrial electricity demand remains quite stable by 2050 compared to 2005.

2.2. THE ONGOING TRANSFORMATION OF EUROPEAN ELECTRICITY MARKETS

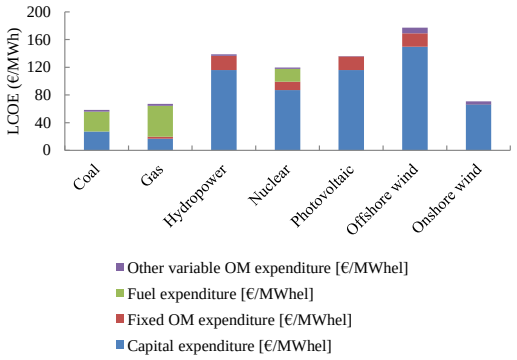
2.2.1. Changing cost structure: high capital costs technologies

From an economic perspective, low-carbon technologies can be considered as low-marginal cost technologies. Low carbon technologies share the same cost-structure: high fixed (investment) and low marginal (operating) costs; whereas conventional fossil fuel-based power sources have lower capital costs and higher operating costs (Graph II.2.4). This has an important effect on the market outcome because as the share of low-carbon technologies increases, average spot market prices may tend to decrease ([46]) and price volatility to increase.

([43]) IEA (2008)
([44]) European Commission (2011a)
([45]) Scenario 1bis: Current Policy Initiatives ; Scenario 2: High energy efficiency ; Scenario 3: Diversified supply technologies scenario ; Scenario 4: High RES ; Scenario 5: Delayed CCS ; Scenario 6: Low nuclear

([46]) Obviously this trend is difficult to predict. Theoretical arguments can be can be used to support the claim that with variable renewables the frequency of low prices may well increase, but the price level where prices are high might also increase, possibly resulting in a neutral or even positive effect on average wholesale prices (see Box I.1.2). As concerns the analytical evidence, the literature review carried out in Pöyry 2010 arrives at the general conclusion

Graph II.2.4: **Levelised costs of fossil fuel and low carbon technologies**



Calculations are based on the year 2011 and do not include carbon costs.
Source: SETIS

Studies have estimated the role that fixed and marginal costs will play in a system dominated by low carbon technologies. The Impact Assessment accompanying the Communication from the European Commission "Energy Roadmap 2050 ([47])" analyses policy scenarios with high penetration of low marginal cost technologies (renewables and nuclear). The study models the evolution of electricity prices, and includes projections on fixed and variable costs of the generation mix induced by the policy. The fixed costs can be identified as the capital costs; while variable costs can be identified with the marginal costs on which the wholesale electricity price is determined. The figures provided in the Impact Assessment clearly show that, under the current policy scenario, with relatively low penetration of renewables, variable and fixed costs represent approximately 50% of the costs each. Under the High renewable penetration scenario, fixed costs constitute more than 2/3 of the overall costs, while variable costs decrease to 1/3. Similar figures are obtained for the high nuclear penetration scenario (see Table II.2.1).

2.2.2. The penetration of variable technologies

Beyond the common cost structure, low carbon technologies differ in the type of capacity they provide: nuclear and hydro plants provide firm capacity (meaning that they can reliably predict the amount of energy they will be able to deliver), whereas wind and solar are variable (or intermittent) technologies which depend on uncertain and difficult to predict weather conditions (at least over a lead time of more than 24 hours). Intermittency is a technical characteristic with great impact on the requirements of the electricity infrastructure, where ancillary services are likely to play a bigger role than what they historically did. In addition, intermittency translates into an economic impact because the unpredictable amount of cheap energy on the market increases the price risk.

The day-by-day market activities are impacted by the intermittent nature of wind and solar power. Increased penetration of this type of technology creates challenges to the reliability of the electricity system: it is not just a matter of having enough installed capacity to meet demand; the issue is rather ensuring that the system is flexible enough to supply electricity when the high share of variable renewables is not able to supply power due to weather conditions.

2.2.3. Changing conditions for investors: lower price and intermittency

Both the electricity price (which depends on the cost characteristic) and the increased uncertainty of revenue streams (due to intermittent energy sources) are crucial elements of the investment decision. If the average electricity price on wholesale markets is too low to cover the fixed costs together with the marginal cost of electricity production, investment is not profitable in expectation, and rational market actors will not undertake it. On the other hand, intermittency in the availability of cheap energy sources increases the variance of price: this means that the price can be low, but also very high in periods when low carbon technologies are not available. This translates into higher investment

that there is a downward movement of wholesale/spot prices due to increased wind power penetration.

([47]) European Commission (2011a)

risk ([48]) negatively affecting the investment decision.

For the electricity system to be reliable, most of low marginal cost units cannot serve the system alone: nuclear plants are, in general, independent from weather conditions ([49]), but they require long booting periods, while wind and solar power (variable renewable sources) are, by definition, dependent on weather conditions which are not easily predictable. This means that large scale deployment of low marginal cost units, and in particular variable renewables, challenges the reliability of the electricity system. For reliability to be maintained, they need to be complemented with other types of resources, like demand response, storage, and generation units for moments of unfavourable weather or to cope with sudden demand spikes requiring fast-responding generators ([50]). Fast responding generation units (mainly secondary reserves) can be procured by transmission system operators (TSOs) through balancing and ancillary service markets It is important to notice, though, that balancing services are not designed for, and hence not likely to substitute other forms of generation for a long duration of high demand and low output from intermittent renewables; to solve this adequacy problem, more resources would be needed.

This means that the introduction of low carbon technologies requires flexibility resources to stay in the market (fast responding firm capacity, currently represented by conventional peaking and mid-range plants, demand response, storage, better use of interconnections and more efficient use of existing plants). With small shares of variable renewables in the system, their intermittency can be smoothed out with existing conventional capacity. But when the variable renewable share reaches higher levels (some estimates put the threshold at 20-25% ([51]) back-up capacity runs for very limited amounts of time, with a consequential decrease in profitability that may force them to exit the market and/or discourages new investment.

Reliability of the system and generation capacity adequacy are interlinked problems. If low carbon technologies depress wholesale prices and cause a lack of conventional capacity in the overall generation mix, the provision of back up capacity in the form of ancillary services and balancing power might become more burdensome, if flexibility is not appropriately rewarded. Hence, the fact that there might be a capacity problem overall, and in particularly for gas and coal, risks increasing the size of the reliability problem.

2.2.4. Marginal cost pricing and investment signal

Whereas the marginal cost based pricing mechanism is widely considered as the best way to achieve efficient use of resource in the short term, its role in guiding investment is being challenged by the changing environment imposed by low carbon technologies, (intermittency, fewer hours run for peaking units and lower market prices). Depending on the techno-economical characteristics of the generation mix, price formation in a short-run, competitive market may not turn out to be functional to send long term price signals to induce investment, (de Castro et al 2010) ([52]).

There is a broad consensus on the need to promote market-based investments without any

([48]) The market structure and technology generation mix play a crucial role in determining the actual risk for individual cases.

([49]) However, nuclear power plants are sensitive to heat waves due to their cooling requirements.

([50]) Traditionally, nuclear power plants have been considered as baseload sources of electricity as they rely on a technology with high fixed costs and low variable costs. This is the most economical and technically simple mode of operation. In this mode, power changes are limited to stability and safety purposes, and they do not adjust production to changes in the load. Developments in nuclear technology are increasing the flexibility of nuclear power plants within a limited scope, and in countries like France and Germany they have partly become load following technologies (again). Their applicability in this area is still limited in most other countries though, and nuclear power plants need to be paired with peaking plants to ensure that demand is constantly met. Hydro power can be of three types: run-of-river plants, which are not flexible enough to be load-following, and reservoir/pumped storage plants, both of which are a very flexible source of electricity. The main limitation of the latter type of plants is that the scope for capacity expansion is rather limited.

([51]) CIEP 2014

([52]) Competition amongst renewable, fossil and nuclear electricity may not only be influenced by national subsidies, tax policies, political objectives and decisions but also by technical aspects. In particular, technical aspects can constitute serious constrains for investment in nuclear capacity such as the minimum size required, the adequacy of the grid to the size of the generation, the need to have adequate cold source (sea or river). These technical constraints also impose additional costs for new entrants.

form of support. However, the views diverge on the way to achieve this end. The main debate is between. *energy-only markets* where prices would be allowed to reach high levels during scarcity hours; or by *capacity remuneration mechanisms*, remunerating some capacities for their availability.

Energy-only markets are potentially able to deliver an investment equilibrium, by pushing out of the market unneeded peak plants when in excess, as well as being able to attract new investment through high prices. Oren (2005) and Hogan (2005) explain that generators should be able to balance their expenditures through bidding higher than marginal costs in hours of supply shortage. For this to happen, markets need to allow prices to reach high levels during scarcity events, which means that price cap, where existent, should be removed (Giuli 2015; Grigorjeva, 2015).

Some authors (Cramton and al, 2013) discuss the ability of scarcity price to fix the investment equilibrium. In reality, markets are imperfect and prices are usually capped to avoid the abuse of market power. One of the difficulties is to set the "value of lost load (VoLL) which corresponds to what consumers would pay to avoid power interruption. For this reason, the authors argue that the scarcity price approach relies on the quality of the regulator's estimate. Finally, the existence and frequency of high prices question the political acceptability of the consequences of an equilibrium based on scarcity prices (ACER, 2013; OECD et al., 2015).

For all these reasons, some authors claim that capacity mechanisms are necessary to compensate for market imperfections. Cramton and Stoft (2005), and Joskow and Tirole (2007) emphasize that there will always be imperfections in the energy-only market leading to, e.g., price spikes and market power, because the demand side does not actively participate in the market. They conclude that there is a need for a different market scheme that would ensure generation adequacy, e.g., a capacity market. Originally, capacity mechanisms were created to make up for the lost profits due to the existence of stringent price caps (Giuli, 2015). Capacity mechanisms can take different forms (see chapter II.1), but they are all based on the idea of remunerating the capacity to produce electricity, rather than the electricity actually delivered.

However, capacity mechanism may have adverse effects linked to the ability to forecast demand and predict the right capacity adequacy. In addition, capacity mechanisms implemented without taking into account cross-border trade is likely to cause over-capacity and distort allocation of investments. (Tennbakk 2013; Grigorjeva, 2015). Moreover, as most of systems remunerate incumbents, the risk is that the existence of remuneration for capacity freezes the market and hampers innovation by delaying investments in new facilities (Grigorieva, 2015). Finally, it needs to be noted that model based analyses show that there is no urgent need for capacity mechanisms in most European countries in the first few years to come (Tennbakk, 2013).

Recently, the investment challenge has been aggravated by the penetration of low carbon technologies, as these technologies tend to lower wholesale prices, hence the remuneration of investors while increasing volatility. Castro and al (2010) show that a system dominated by low carbon technologies leads to reduced market prices independent of production costs and does not guarantee the financial viability of existent firms., Cramton et al. (2013) argue that renewables aggravate the adequacy problem because their production is entirely price-inelastic (due to marginal costs close to zero). Because of this characteristic, renewables intensify demand fluctuations, and thereby price fluctuations. The authors add that with rising renewable in-feed, generation adequacy is challenged because, conventional investments get less attractive due to lower load factors.

On the issue of increased volatility and its effect on investments, Blyth et al. (2015) analyse the effects of an increasing share of renewables on the price formation mechanism. They demonstrate that over time the wholesale market will present an increasingly less attractive risk/return profile, with lower average prices and higher volatility, which will induce market concentration as larger companies can more easily bear these risks. They also show that inadequate near-term investment signals emerge when market participants are confronted with behavioural considerations of risk, limited foresights and excessive discounting. Similarly, Pikk and Viiding (2013) analyse the potential impact of more renewable electricity production on wholesale prices in the NordPool

spot market, in the context of significant help from government support schemes for investment in renewable production capacity. Their results are in line with the findings of Blyth et al. (2015) as they show that, ceteris paribus, NordPool Spot is likely to have very high price volatility in the future and alternative revenue sources are required for new investment.

This dynamic is the starting point for a reflection by OECD et al. (2015), which observe that the design of wholesale electricity markets is not strategically aligned with the transition to low carbon. The current market design is failing to provide the visibility of future electricity prices that would help secure investment in the low-carbon, high-capital cost technologies needed for the transition. The reflection leads to the conclusion that, despite the fact that wholesale electricity markets will remain useful for the least-cost dispatching of existing capacity, left on their own, they would require repeated periods of very high prices, with a high price on CO2, and scarcity periods and risks of rolling brown-outs, before investors would unlock financing of these technologies. The OECD et al. claim, instead, that the right investments could be achieved more cost-effectively if new forms of market arrangements were agreed. Similarly, IEA (2015) questions the ability of the current model of liberalised markets with a carbon price to deliver investment at a scale and pace needed to achieve decarbonisation. It concludes that additional instruments to secure investments for decarbonisation might be needed on top of a carbon price and well-designed short term markets.

2.3. CONCLUDING REMARKS

Investments in the power generation are expected to play a central role in the transition to low carbon economy. Not only the electricity sector has a large decarbonisation potential; it is also expected to contribute to the decarbonisation of other sectors of the economy by supplying low carbon electricity.

The increasing share of low carbon technologies in the electricity mix is likely to lower the prices on the spot market. Under current market arrangements, this corresponds to the day ahead market. These price developments can be explained by the price formation (i.e. assuming generators bid according to their marginal costs) and the cost structure of these technologies with high fixed costs and low operating costs. In such a system, there is a risk that a market price based on the operating cost of the marginal unit may not be sufficient for investors to generate sufficient revenue to cover their fixed costs. This is under the assumption that technologies with low variable costs will dominate the market and therefore regularly act as the marginal producer.

This translates into a risk that the current arrangements of wholesale markets will not provide the proper incentives for long-term investment in the power generation sector. Markets are supposed to serve two functions: optimisation of resources already in place, and driving investment for the future. Whereas the electricity market serves the first function well, it is not clear whether the current electricity market design will be sufficient to convey the right long term investment signals in a system dominated by low-carbon technologies with low operating costs. However, a proper market framework is important to make these investments happen.

Part III

Reconciling markets with investment signal: which market arrangements?

INTRODUCTION

The increasing penetration of low carbon technologies is changing the market reality and poses several challenges for both investors and public authorities. From a dynamic perspective, the transition to a low carbon economy influences both prices and capacities and leads to new equilibriums for each stage of the transition. This part aims to provide an economic framework for the transition to a low carbon economy and discusses possible market arrangements.

Chapter one analyses the impact of the decarbonisation using different sequences – yesterday, a world dominated by conventional fuels; today with a transition phase led by the penetration of new technologies and, tomorrow with a decarbonised world where electricity is mostly produced by low carbon technologies.

Chapter two reviews the challenges for each sequence – today and tomorrow – and identifies possible market-based arrangements that would incentive investments while minimising the cost for society.

1. THE ECONOMICS OF THE TRANSITION TO LOW CARBON ECONOMIES

The increasing penetration of low carbon technologies is affecting the cost structure and composition of the technology mix (see part I and II). This impacts the price formation on the market and hence the way investors recoup the costs for their investments.

The objective of this chapter is to understand the evolution of the investment conditions in power markets during the decarbonisation process. Section 1 analyses the impacts of low carbon technologies on prices and quantities. Section 2 looks at the cost developments and learning potential of low carbon technologies. Section 3 concludes.

1.1. THE ECONOMICS OF LOW CARBON TECHNOLOGIES

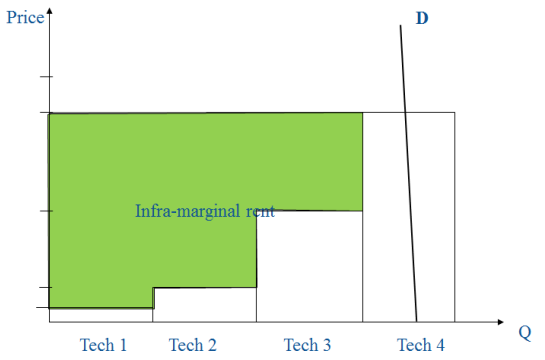
1.1.1. Impact of low carbon technologies on prices and capacities

The transition to a low carbon economy leads to a shift to technologies with high fixed costs and low operating costs (see part II). This evolution changes the cost structure as well as the total capacity of the electricity system in the short and medium run. From an investor's perspective, the overall conditions to invest will change due to the impact on the price of the energy transition, thereby changing the incentive to invest or not. From public authorities' perspective, it is important that the impact on the capacity and prices induced by the changing structure of the electricity mix remains compatible with an efficient and cost-effective electricity market.

Investment decisions need long term predictability, which makes it important to understand the consequences of the transition to low carbon technologies in both the short and medium term. The market transition can be summarised by three chronological stages with their own characteristics in terms of price and production conditions. In order to understand the impact of this development, three power systems are constructed that represent each stage of the energy transition, from yesterday (conventional phase – stage 1) to today (transition phase – stage 2) and tomorrow (decarbonised phase – stage 3) ([53]). During the transition phase, most of low carbon technologies are not yet competitive and would not enter in the market without any form of support. During the decarbonised phase, it is assumed that low carbon technologies dominate the technology mixes of the European power systems and compete on the market. Each stage corresponds to a changing electricity mix induced by the increased penetration of low carbon technologies and leads to different equilibriums in terms of price and quantity. The magnitude of the quantity (or capacity) and the price (cost structure) effect differs across the stages of the transition.

Remuneration for producers relies mainly on the price fixed by the marginal unit (see chapter II.1). Each technology available on the market will face a remuneration which is composed of the sum of infra-marginal rents gained during the different periods of time as well as scarcity rents when demand is scarce (see graph III.1.1 and III.1.2 and annex 3). These rents allow for the recovery of the fixed cost of the peaking units, and also contribute to the cost recovery of the other technologies.

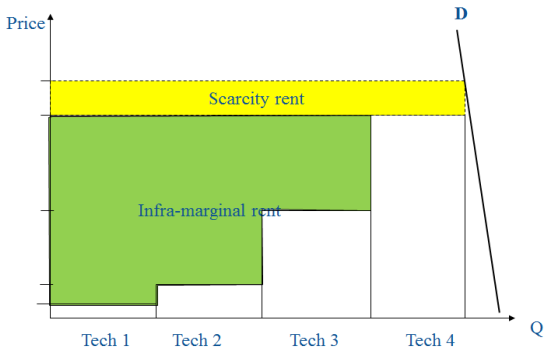
Graph III.1.1: **Generic merit order curve under no capacity constraints**



Source: European Commission

([53]) For example, under the different scenarios[53] of the Energy Roadmap 2050, low carbon technologies start producing around 65% to 70% of the gross electricity generation by 2025-2030. See European Commission (2011a).

Graph III.1.2: **Generic merit order curve under scarce capacity**



Source: European Commission

The penetration of low carbon technologies changes the merit order curve. Under the transition phase, it is assumed that current market arrangements remain and electricity demand is constant ([54]). The introduction of low carbon technologies changes dynamically the merit order curve by pushing the supply to the right for a certain period of time proportional to their capacity factors. By contrast, when these technologies are not operating, the power system uses conventional technologies (see graph A3.3 of annex 3). In the decarbonised phase, merit order curves are getting flatter with steeper ends that reflect a technology mix dominated by low carbon technologies with low variable costs and conventional capacity to ensure that demand is met at any time. Indeed, low carbon technologies are able to operate during most of the year due to a high degree of European market integration that allows drawing on their spatial and time complementarities. This, in particular, changes the operating conditions (reduction of number of hours) of peaking technologies.

As a result, and under current market arrangements, two main effects would be at play during the energy transition that affect the level of installed capacity and market revenues. The first effect is a *capacity adjustment effect*, which corresponds to a change in supply and demand that requires the production to be adjusted to the new conditions. Depending on the stage of the transition, this adjustment can be positive or negative. The second effect is a *revenue effect* which is due to the entry of technologies with lower variable costs than the existing technology mix. In both stages, this revenue effect is negative for producers (see Box III.1.1) ([55]).

The transition phase under current market arrangements, which corresponds to the situation of today, is likely to benefit from lower equilibrium prices ([56]), but would display transitory over-capacity of installed capacity. During the transition phase, low carbon technologies are continuously introduced in order to meet the EU climate and energy targets during the transition phase. This may create temporary overcapacity that would be corrected by adjustment of the total generating capacity to reach a new equilibrium, for instance through decommissioning of plants with the highest operating costs. As the marginal cost of total supply would decrease as low carbon technologies enter into the market, this would result in a new equilibrium price that is lower than the previous equilibrium price, triggering a revenue reduction for the producers (see Box III.1.1).

The decarbonised phase, which is representative of the market of tomorrow, is likely to be dominated by a much lower equilibrium price for most part of the year and by the need for strong price spikes (and its associated uncertainty) to recoup the fixed cost of investments. Under the decarbonised phase, the energy transition is achieved, i.e. low carbon technologies are dominating the technology mixes of the European power systems. Due to the high penetration of low marginal cost carbon technologies, the supply curve becomes flatter with steeper end compared to the transition phase

([54]) Holding electricity demand constant is a conservative assumption as electricity is expected to grow through its deployment in the transport and heating and cooling sector. However this is also expected to be compensated by improved energy efficiency. Considering the uncertainties on the electricity growth in the future and for the sake of the clarity of the analysis, demand remains constant.

([55]) The analysis considers the revenues induced by wholesale price evolution. In reality, generators get other forms of revenues such as for balancing services. Other sources of revenues, for instance, through more developed balancing or intraday markets or unconstrained scarcity pricing could counter this decrease in revenues.

([56]) The extent of the price decrease depends on several factors such as a change of the carbon price during the transition phase. Quantifying it precisely goes beyond of the scope of this report.

resulting in lower price equilibrium in most part of the year and high prices when demand is high and capacity is scarce. The feasibility of frequent and intense price spikes is uncertain in the future, notably due to factors such as public acceptance, regulatory intervention to prevent market power, low price caps set in power markets. Due to this uncertainty, a revenue decrease for the producers can overall be expected. As prices are lower, demand increases (as a result of the elasticity of demand), which requires increasing the quantity produced. The example presented in box III.1.1 is neutral on the way to achieve this new equilibrium. For example, the increase in quantity can be achieved through the addition of new capacity (investments). An alternative would be to maintain some capacity from the transition phase, provided they have the right flexibility and CO2 emissions characteristics and the (stranded) cost of keeping them is not too high ([57]).

([57]) It is noted that the extent of capacity adjustments will depend also on the evolution of the future electricity demand.

Box III.1.1: Price developments and market adjustment through the energy transition

Graph 1 aims at capturing the effect of the penetration of low carbon energy technologies on market prices and quantities throughout the energy transition in an aggregated and simplified form ([1]), all other market factors such as carbon price being kept constant. It is based on the analysis described in Annex 3. The three demand periods of each stage - base, semi-based and load - have been averaged into a single annual demand – D.

The starting point is the conventional phase - stage 1- described above and depicted by point A when the supply curve (S1) and demand curve D meets. The effect of an increasing penetration of low carbon technologies as described under the transition phase - stage 2 on the supply curve S1 is a shift to the right leading to supply curve (S2). The low carbon technologies that are introduced during the transition phase, at first, add up to the stock of technologies existing under stage 1. This creates a temporary overcapacity (Q'2). Indeed, this potential quantity produced cannot meet demand; hence the second step is a market adjustment. This model assumes that economic agents make their decision with the expectations that supply shocks will become continuous as low carbon technologies will be continuously introduced until the power sector is fully decarbonised. Consequently, the plants to leave the market first will be the plants that do not recoup part of their fixed costs, i.e. high operating cost plants. These results in a shift downwards to point B to meet the new quantity demanded. At the same time, the new equilibrium price P2 is lower than the previous equilibrium price P1 due to the entry of technologies with lower variable costs than the existing technology mix. Altogether the shift from stage 1 to stage 2 (S_1S_2) can be decomposed as follows:

(i) a ***revenue reduction effect***, measured by the area AB"CD, for producers owning capacities producing Q1 due to the price decrease from P1 and P2;

(ii) a ***capacity adjustment effect*** from Q'2 to Q2, measured by the area B'A'B, as this over-capacity is not producing due to a lack of quantity demanded. Therefore, the quantity produced has to be reduced to meet demand.

(ii) a net ***capacity adjustment effect*** resulting from the increase in production from Q1 to Q2 (once the overcapacity has been adjusted) The net effect is null as consumer gains (area AB"B) are compensated by producers revenue reduction (area AB'B);

The overall effect of going from the conventional phase (stage 1) to the transition phase (stage 2) can be summarised as follows:

$$S_1S_2 = revenue\ reduction\ effect\ (B'DCB) + (negative)\ capacity\ adjustment\ effects\ (B'A'B)$$

To reach the decarbonised phase - stage 3, additional low carbon technologies are added. It is assumed that low carbon technologies are able to operate during most of the year ([2]). In this configuration, the increased penetration of low carbon technologies results in a change in the technology mix, with a steeper end representing the supply costs of flexible capacities needed to meet high demand and to compensate for the resource availability and firmness of low carbon technologies to meet demand. This results in a shift of supply curve (S2) to the right to supply curve (S3). Under these circumstances, for the capacities producing Q2, this means a revenue decrease due to a decrease in the market price from P2 to P'3. However, as prices are lower, the quantity demanded increases compared to the end of the transition phase as a result of the elasticity of demand. This requires increasing the quantity produced from point E (Q2) to point G (Q3)

([1]) For instance, the aggregation removes the difference in price equilibrium at different hours of the day, which is key to capture the precise revenue that can be obtained by the different elements of the technology mix. Additional incomes from other markets such as ancillary and balancing markets are not included, although they can play a significant role in the financial balance of fast ramping units.

([2]) This assumption is plausible as it draws on spatial and time complementarities induced by high market integration and regional coordination.

(Continued on the next page)

Box (continued)

reaching a new and higher equilibrium price P3. Overall the shift from stage 2 to stage 3 (S_2S_{32}) can be decomposed as follows:

(i) a ***revenue reduction effect***, measured by the area BEFC, for producers owning capacities producing Q2 due to the price decrease from P2 and P'3;

(ii) a ***capacity adjustment effect*** resulting from the increase in production from Q2 to Q3 due to the elasticity of demand.

(iii) a net ***capacity adjustment effect*** resulting from the increase in production from Q2 to Q3 with revenue increase for producers (area IEG) and a revenue reduction effect (area BIG) as the capacity Q2Q3 does not benefit from price P2.

And (iv) a ***positive revenue effect***. The increase from Q2 to Q3 leads to a revenue increase for producers due to the price increase from P'3 to P3 (area FHIE). However, this revenue increase is not sufficient to compensate the revenue reduction (CBHI).

The overall effect of going from the transition phase (stage 2) to the decarbonised phase (stage 3) can be summarised as follows:

$$S_2S_3 = revenue\ reduction\ effect\ (BGHC) + (positive)\ capacity\ adjustment\ effect\ (IEG)$$

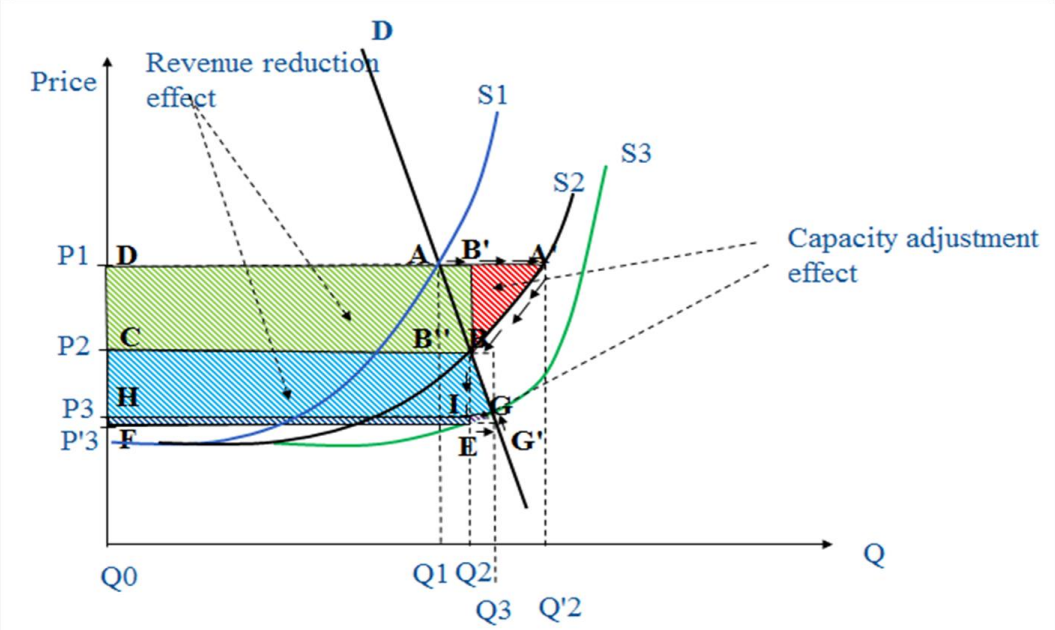
The financial position of all technologies will dependent extensively on the frequency and ability of prices to reach high levels. The feasibility of such price spikes is uncertain. The availability of variable low carbon technologies (including hourly, seasonal and multi-annual variability) with respect to its assumed firmness will also play a role. For instance, if the available capacity of variable low carbon technologies is higher than the assumed firmed capacity, prices will be low (shift to the right of the supply curve). If variable low carbon technologies does not operate or at a reduced level, prices will reach high levels that include scarcity pricing (shift to the left of the supply curve).

Furthermore, managing the overcapacity Q'2Q2 under phase 2 and the capacity increase Q2Q3 under phase 3 poses an investment dilemma. First, it depends on the demand evolution (which is assumed to be constant in this model). Second, dealing with the overcapacity can be done by decommissioning or by keeping capacities idle, for instance for security of supply reasons, which has a cost. In electricity markets, these costs which correspond to existing investments that have become redundant are called stranded costs. As regards stage 3, an alternative to expanding capacities would be to maintain some capacities from the overcapacities of phase 2, provided they have the right flexibility and CO2 emissions characteristics and the stranded costs are taken into account.

(Continued on the next page)

Box (continued)

Graph 1: **Price development and market adjustment through the energy transition**



Source: European Commission

It has to be noted that the graph presents a comparative statics exercise which is suited to analyse the effects of the supply shock caused by an increased share of low-marginal cost technologies. Hence, the effects described refer to a scenario where all other parameters (demand, input costs, carbon price, etc) remain constant. Indeed, including the dynamics of all other relevant parameters would give more complex results. However the direction of changes would normally remain the same as in the static analysis. For instance, the carbon price is likely to be higher in phase 2 than in phase 1, implying that the price reduction from P1 to P2 would be smaller.

Furthermore, by nature of the merit-order curve i.e. stacking of technologies from low operating cost to high operating costs, the revenue reduction effect is more pronounced during peak periods than during base load periods as shown under graph 2.

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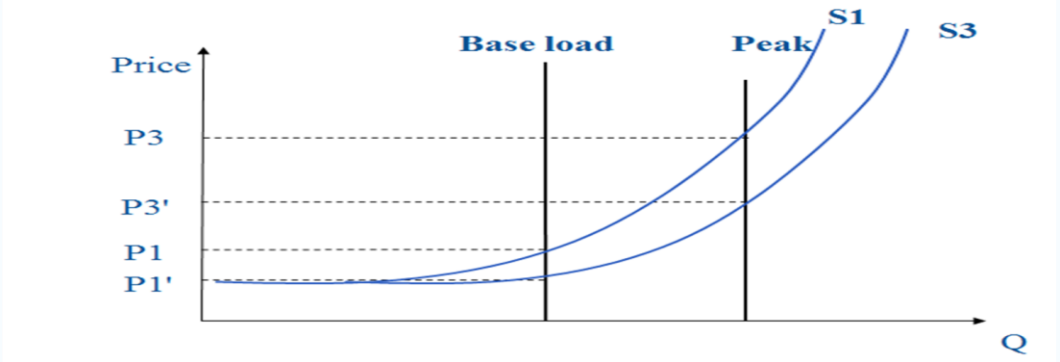
Box (continued)

Graph 2: **Difference in price developments between base load and peak periods**



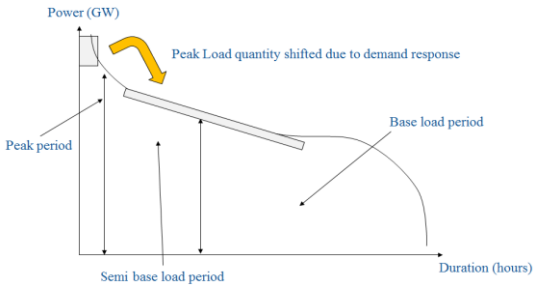
Source: European Commission

1.1.2. Impact of Demand Response

Demand response enables consumers to change voluntarily their consumption pattern in response to market signals. Consumers can also themselves (or through aggregators) place bids on power exchanges ([58]) and thereby agree to change their demand for electricity at a given point in time ([59]). In practice, consumers would be asked to decrease their consumption when the power system is facing a stress or peak and incentivised to consume in periods of low demand or over-capacity. Demand response allows also consumers to reveal their willingness to pay during periods of scarcity, which would provide reliable information to investors with respect to investments in peaking capacities.

With the development of demand response, the revenue streams for the different technologies can be expected to slightly decrease or remain equivalent ([60]) to the previous situation with inelastic demand, while revenue needs in peaking technologies would decrease. This effect is shown in Graph III.1.1, where demand response tends to increase consumption during semi-base load and base-load periods where prices are lower at the detriment of the peak period.

Graph III.1.3: **Impact of demand response on the load duration curve**



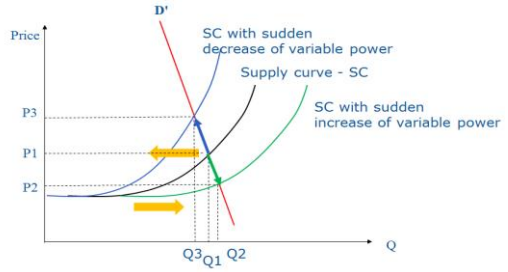
Source: European Commission

Demand response would also mitigate the impact of the variability of wind and PV generation on market revenues. In the case of sudden and unforeseen increase in wind or PV generation (supply curve with sudden surge in output in Graph III.1.2) that normally would tend to depress prices, the effect of demand response would be to consume more during this period (shift demand from Q1 to Q2), which is effectively a transfer of consumption from a higher price period to this low price period. The resulting impact on the different technologies would be overall less

([58]) in particular, in the intraday or balancing markets, as these prices are more likely to reflect the price differential required to incentivise consumers to reduce their load.
([59]) European Commission (2013 b)
([60]) Due to the fact that an increase in demand in base or semi base load periods will increase their relative prices compared to the scenarios without demand response.

revenue for power producers ([61]). The opposite would happen in case of a sudden decrease of wind or PV power generation that could trigger high prices; the effect of demand response would be to absorb this decrease in production by shifting the consumption to other periods (from Q1 to Q3), hence preventing periods of scarcity pricing. Assuming schematically an equal probability of sudden positive or negative output of wind and PV production, the development of demand response would tend to mitigate their effect on market revenues.

Graph III.1.4: **Short-run impact of demand response on the sudden changes of power outputs**



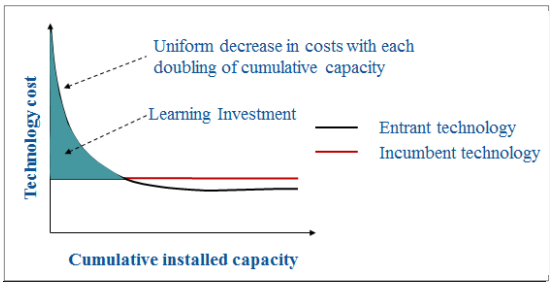
Source: European Commission

1.1.3. The dynamic of the transition: addressing the competitiveness of new technologies

Most low carbon technologies in the transition phase are entrant technologies, which are not yet fully competitive in the market (e.g. off-shore wind, advanced bio-power, carbon capture and storage). Therefore, the level of fixed costs is influenced by the degree of maturity of these technologies and also their capacity of further decreasing costs. This means that, as regards the dynamic of the transition, the investments in the different technology mixes composing the transition phase and decarbonised phase will depend on the capacity of these technologies to reduce their costs proportionally to the decrease in revenues that occurs during this transition through the different stages.

This cost reduction should take place notably through learning effects. Learning effects represents the observation that the cost of a technology decreases by a certain amount with every doubling of installed capacity ([62]). Each time a unit of technology is manufactured, some knowledge and learning accumulates that makes the future technology units cheaper to produce. This concept is also used to extrapolate cost reductions to future cumulative production levels and assess the "learning investment" which corresponds to the difference between the costs of the entrant technology and the cost of incumbent technologies ([63]) (Graph III.1.3). Without learning effects to compensate for the revenue decrease, no investments would take place or public support would be needed.

Graph III.1.5: **Cost development of an entrant and an incumbent technology**



Source: JRC, European Commission

Learning effects are realised through research and innovation, but can also be incentivised by support to deployment ([64]). The rationale is that deployment of these new technologies increases the cost reduction, suggesting that further deployment decreases costs. However, as mentioned by Stern (2006), reversing the causation may lead to disappointing results, hence the need to reflect on the potential of these new technologies to minimise the costs of development.

([61]) The extent of this expected decrease will depend on the level of demand elasticity as lower prices can lead to higher consumption.

([62]) Wene, C.-O. (2000).
([63]) JRC (2012).
([64]) This has been the approach to support renewable development in the EU. The revised State aid Guidelines take account the different level of maturity of renewable technologies and acknowledge the need to expose the most mature ones to market signals.

1.2. INVESTMENT CRITERION IN LOW CARBON TECHNOLOGIES IN A CHANGING ELECTRICITY SYSTEM

1.2.1. The decision to invest

The investment decision is based, and will remain based, on the expected profits. To invest in any technological projects, investors require that revenues recoup *at minima* the total costs incurred during the project life time (e.g. technical or economic life) of the project. This investment criterion can be reformulated into the following revenue/cost expenditure balance as follows:

$$\pi_i = \sum_{y=1}^{PLT} \frac{\pi_i^y}{(1+d)^y} > 0$$

with

$$\pi_i^y = \left\{ \sum_{t=1}^{n} R_t^{i,y} - \left(\sum_{t=1}^{n} TC_t^{i,y} \right) \right\}$$

With:

π_i^y : Annual profit for technology i, in EUR/yr in year y

PLT : project life time (in year)

d: discount rate

t: index of a demand period of a year, e.g. base, medium and peak

$R_t^{i,y}$: Revenue for technology i during demand period t and in year y. $R_t^{i,y}$ can be written as $P_t^y Q_t^{i,y}$, where, P_t^y is the equilibrium price for demand t (in $\frac{\text{EUR}}{\text{MWh}_{\text{el}}}$) and $Q_t^{i,y}$ is the energy quantity generated by technology i during the demand period t in MWh_{el} and in year y.

$\sum_{t=1}^{n} TC_t^{i,y}$: Annual total costs for technology i in year y, in EUR/yr. This is equal to $\sum_{t=1}^{n} V_i^y Q_t^{i,y} + FC_i^y$, *with* V_i^y *: V*ariable cost of technology i, in $\frac{\text{EUR}}{\text{MWh}_{\text{el}}}$ and FC_i^y Annual fixed cost *of* technology , in EUR/yr, in year y.

This investment criterion implies that revenues acquired by technology i through infra-marginal rents during the different periods of time of a year and over the entire project life time shall cover its fixed costs.

$$\sum_{y=1}^{PLT} \frac{\sum_{t=1}^{n} P_t^y Q_t^{i,y} - \left(\sum_{t=1}^{n} V_i^y Q_t^{i,y} \right)}{(1+d)^y} \geq \sum_{y=1}^{PLT} \frac{FC_i^y}{(1+d)^y}$$

or

$$\sum_{y=1}^{PLT} \sum_{t=1}^{n} \frac{\mu_t^{i,y}}{(1+d)^y} \geq \sum_{y=1}^{PLT} \frac{FC_i^y}{(1+d)^y}$$

With $\mu_t^{i,y}$*:* infra-marginal rent for technology i during period t and in year y

1.2.2. Quantification of the investment criterion

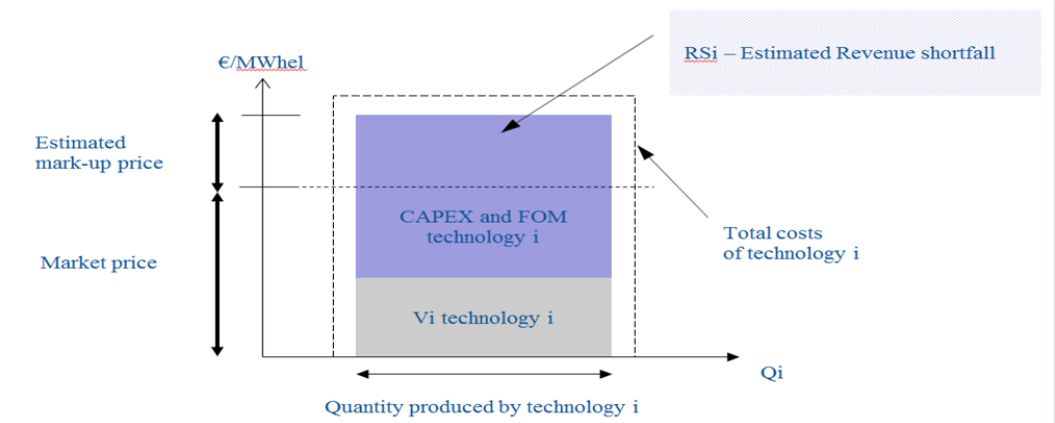
Investing in low carbon technologies (for which the fixed costs account for about 70% of their total costs) under market conditions and without any support will depend on the relative cost levels of these technologies compared to the other technologies of the system. An important aspect will be their learning potential over time, i.e. the ability to accommodate for the decreasing rate of revenues through cost reduction as the energy transition progresses (from the convention phase to the decarbonised phase).

Box III.1.2: **Quantifying the investment criterion**

Sophisticated market and technology models would be necessary to quantify the precise shortfall or excess revenues that a given technology could acquire under the different market frameworks presented under section III.1.1. However, these calculations can be simplified by looking, at first, at the revenues that would be acquired by a given technology if an open cycle gas turbine (OCGT) ([1]) would determine the market price and if each low carbon technology could operate up to its maximum capacity ([2]). Such a situation would be an extreme and favourable situation compared to the conventional phase. Therefore, if any revenue shortfall would be detected under these assumptions the findings would de facto apply to all stages of the energy transition as described in the previous section.

To do so, a model is developed that calculates the difference between the revenues generated when the price is fixed by an OCGT (i.e. its marginal cost) and when a given technology runs to its maximum capacity factor and the total expenditures that this technology needs to recover. Graph 1 summarises the methodology used.

Graph 1: **Methodology for quantifying the investment criterion**



Source: European Commission

Five low carbon technologies are considered in this analysis. It is assumed that they are competing on the market without subsidies: offshore wind farm; onshore wind farm; nuclear power plant (Generation III); hydropower plant; and pulverised Coal fired power plant equipped with carbon capture and storage.

The estimated revenue shortfall for technology i (RS_i) that should be acquired normally through infra-marginal rents is obtained by levelizing the investment criterion presented under section III.1.2.1 over the project lifetime. In this model, no commodity or fuel escalation is assumed after the start of the project. As a result, the revenues and costs for each year of the project lifetime equals those of the starting year. This is a strong assumption as, for instance, commodity and CO2 prices are expected to change over the technology lifetime. Nonetheless, this reflects as well the fact that investors are facing difficulties to predict the evolution of these prices in the future as experienced recently with coal and gas prices or CO2 prices, beyond what is known to them at the start of the project. Overall, this assumption would over-estimate the price differential between the low carbon technologies and the OCGT in case of commodity and CO2 price escalation during the project lifetime.

([1]) OCGT is the reference peaking unit today and is likely to remain so in the future. Other technologies such as storage, demand response could also play an important role as peaking units in the future.
([2]) i.e. the maximum number of hours at rated power that a technology can operate during a year if not limited except by its technical constraints such as resource availability, maintenance etc.

(Continued on the next page)

Box (continued)

$$RS_i = (V_i * Q_i + FCi) - P_{OCGT} * Q_i$$

Or, calculating it in estimated price equivalent or mark up:

$$M_i = \left(V_i + \frac{FCi}{Q_i}\right) - P_{OCGT}$$

With:

$RS_i = M_i * Q_i$

Q_i = Rated Power * Capacity factor, in MWh_{el}

M_i : Estimated mark-up required by technology i to recoup all its costs, in $\frac{€}{MWh_{el}}$

V_i: Variable cost of technology i $= VOM_i + Fuel\ Cost_i + CO2\ T\&S_i + CO2\ emitted_i * P_{CO2}$

- VOM_i: annualized variable operation and maintenance expenditures of technology i in $\frac{€}{MWh_{el}}$

- $Fuel\ Cost_i$: annualized fuel expenditures of technology i in $\frac{€}{MWh_{el}}$

- $CO2\ T\&S_i$: when relevant, annualized CO2 transport and Storage expenditures of technology i in $\frac{€}{MWh_{el}}$

- $CO2\ emitted_i$: specific CO2 emissions of technology i in $\frac{t_{CO2}}{MWh_{el}}$

- P_{CO2} : the price of CO2 emission allowance in $\frac{€}{t_{CO2}}$

$\frac{FC_i}{Q_i}$: Annual fixed cost for technology i $= CAPEX_i + FOM_i$, in $\frac{€}{MWh_{el}}$

- $CAPEX_i$: annualized capital expenditure of technology i in $\frac{€}{MWh_{el}}$

- FOM_i: annualized fixed operation and maintenance expenditure of technology i in $\frac{€}{MWh_{el}}$

P_{OCGT} = Variable costs of OCGT = V_i as above with i=OCGT

The methodology used to calculate the annualized capital expenditure is described in Annex 4 and is derived from ([3]). It includes learning effects for the 2020 and 2030 periods. The learning effect is captured in the model through the One-Factor-Learning Curve that links the global cumulative manufacturing (approximated by the installed capacities) and the unit production costs. This relation is determined by the learning elasticity or the learning rate (see Annex 4). The CO2 and fuel prices used are taken from the EE27 scenario of the Impact Assessment of the energy efficiency review and its contribution to energy security and the 2030 Framework for climate and energy policy ([4]).The techno-economic data for the various technologies used in this analysis are taken from the on-line Strategic Energy Technologies Information

([3]) European Commission (2008)
([4]) CO2 prices: 10 €/tCO2 in 2020 and 40 €/tCO2 in 2030. See European Commission (2014f).

(Continued on the next page)

Box (continued)

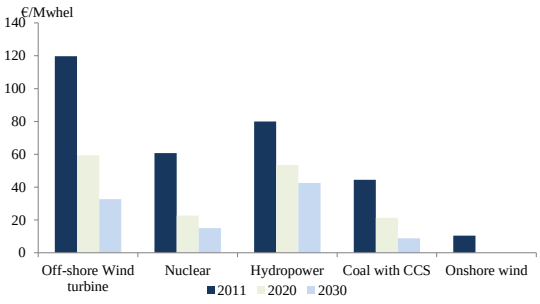
System Database (SETIS) ([5]). These are consistent with other sources such as Bloomberg New Energy finance ([6]).

([5]) SETIS (2015)
([6]) BNEF (2014) – available at https://www.iea.org/media/workshops/2014/solarelectricity/bnef2lcoeofpv.pdf

The cost performance of low carbon technologies is improving over time, which means that they would be able to cover an increasing part of their costs through the market in the future. This is explained by research and innovation efforts that decrease the cost of technologies over time as well as the expectation of increasing fuel prices and CO2 prices in the long run**.** For mature technologies such as onshore wind, market revenues as modelled with the optimistic assumptions presented in Box III.1.2 would be sufficient to cover investment costs by 2020 and 2030.

Nonetheless, most of the low carbon technologies will not be competitive during the transition phase. A price gap is likely to remain for less mature low carbon technologies until 2030, which will prevent them to cover their total cost with market revenues. This means that investors would not have incentives to invest in low carbon technologies under these market conditions, unless the price gap is expected to be covered over time.

Graph III.1.6: **Estimated mark-ups for low carbon technologies with Open gas Cycle Turbine as a marginal producer**



Source: European Commission

1.3. CONCLUDING REMARKS

The success of the transition depends on the capacity of the low carbon technologies to reduce their costs and to improve their integration into the power system. The cost performance of low carbon technologies is improving over time due notably to learning effects. Nonetheless, most of low carbon technologies will not be competitive during the transition phase which means that investors would not have incentives to invest in low carbon technologies under these market conditions, unless the price gap is expected to be covered over time.

Under the current market arrangements which include institutional barriers, the increasing penetration of low carbon technologies is changing the way the market is functioning. In the short to medium term, further investments in low carbon technologies are likely to result in price decreases. Without parallel exit of sufficient conventional capacity, this would also result in over-capacities that would further decrease prices. Both effects would contribute to the emergence of specific investment challenges to be addressed.

As the energy transition approaches completion, the cost structure effect of low carbon technologies is setting prices for most part of the year, putting a strong emphasis on very high (and/or frequent) price spikes to allow recoup investment costs. Considering the uncertainty of these price spikes, notably due to factors such as public acceptance, regulatory intervention to prevent market power, low price caps set in power markets, the cost structure effect of low carbon technologies risks being dominating which could induce a lower equilibrium price on the wholesale market, challenging further the way investment costs are recouped. This development would be influenced by the carbon price.

2. MARKET ARRANGEMENTS THROUGH THE ENERGY TRANSITION

The investment conditions for new technologies will be evolving significantly as the energy transition progresses (see chapter III.1). Investment decisions are system dependent. Therefore, for investments to happen, it requires market frameworks that match over time the economics of power systems with higher levels of decarbonisation.

This chapter analyses the investment conditions in two power systems representatives of the middle point and end point of the energy transition: *power systems under decarbonisation* and *decarbonised power systems.* This corresponds to the transition phase and decarbonised phase of section III 1.1 respectively. Section 1 summarises investment challenges for the transition phase and investigates possible market arrangements to strengthen the market framework. Section 2 performs a similar analysis for the decarbonised phase. Section 3 concludes.

2.1. CURRENT TRENDS

A well-integrated internal energy market with increasing demand response and decarbonisation of energy supply is the cornerstone of the EU strategy to achieve a low carbon economy by 2050.

The starting point of this analysis is, therefore, the current market model pursued in the European Electricity Target Model ([65]) and characterised by an increased integration of power markets at EU level with more cross-border interconnections and enhanced regional cooperation. Under this market framework, prices are determined under the marginal cost pricing principle, although wholesale prices are currently capped either by regulations or through rules imposed by power exchanges. Demand response is progressively deployed pushed notably by the regulatory framework ([66]).

The current market framework also includes CO2 pricing through the European Emission Trading System (ETS). The European Council has agreed to strengthen the ETS through the introduction of a market stability reserve and a faster reduction of the number of allowances as of 2021, by increasing the annual linear reduction factor which determines the EU ETS cap.

The market framework is also complemented by various interventions on the market. For instance, national market support schemes aim at fostering investments in low carbon technologies. Capacity mechanisms in some Member States aim at incentivising investments to ensure that a sufficient amount of capacity will be available. Rules for both types of support schemes are included in the guidelines on State aid for environmental protection and energy 2014-2020 and a number of Communications from the Commission ([67]).

2.2. CHALLENGES FOR INVESTMENTS AND OPTIONS IN POWER SYSTEMS UNDER DECARBONISATION (TRANSITION PHASE)

2.2.1. Challenges

A key challenge for investors under the transition phase might be the decrease of market revenues triggered by the penetration of low carbon technologies. This phenomenon is due to the capacity adjustment and revenue reduction effects identified in section III 1.1. This expected decrease in market revenues might risk stifling investments and/or increasing their cost through higher market premiums, while deteriorating the financial positions of existing power plants. At the same time, the risk of "non-investments" due to the decrease of market revenues might place a risk of

([65]) Network codes are the main vehicles for implementing the Target Model. There are ten network codes currently under development, grouped into three main categories: *Connection Codes*, *Operational codes and Market codes*. https://www.entsoe.eu/major-projects/network-code-development/Pages/default.aspx

([66]) This includes the Electricity Directive (2009/72/EC), the Energy Efficiency Directive (2012/27/EU), and the development of network codes for the internal electricity market (particularly those on demand connection, system operation and balancing)

([67]) European Commission (2013 b), European Commission (2013 c), European Commission (2013 d)

security of supply and of increasing need for market support with impact on consumer bills and potentially also on public finances.

Less mature low carbon technologies will continue to suffer from a price gap that will prevent them to cover their total costs from market revenues during the transition phase ([68]). Investments in these technologies will therefore not take place under market conditions. This poses a challenge to public authorities to improve the cost-effectiveness of support schemes and make them more market-based, and to integrate low carbon technologies in the market. This effect will be enhanced by the revenue compression occurring when the share of low carbon technologies is increased.

Under the transition phase, there will also be a need to manage an over-capacity in generation. As the energy transition is pushed by the policy objective of decarbonisation, this will mean that there will be an overcapacity in fossil fuel generation to manage, while maintaining security of supply through investments in flexibility solutions such as demand response, flexible generation, storage and grid expansion. Disinvestments are currently taking place limited to some extent by existing exit barriers and mostly in gas-fired power plants as a result of low wholesale and CO2 prices together with low coal and higher gas prices. This may pose a challenge in terms of security of supply as these gas plants are the most flexible generation units, which play a key role in maintaining the reliability of the power system ([69]).

2.2.2. Different forms of market arrangements

The investment challenges identified above would intensify without adjustments to the current market framework as the decarbonisation of the European power systems progresses through the transition phase in line with the EU Energy and Climate Agenda.

The effectiveness of the market framework can be analysed through the following dimensions: level of price and market risks for an investor, degree of public intervention and level of competition. An additional issue is how to strengthen price signals based on market arrangements to cover the price gap that remains for some low carbon technologies in the most effective way, while incentivising investments in flexible solutions to ensure security of supply.

By definition, the objective of market arrangements should be to minimise public support in order to make the penetration of low carbon technologies cost effective for consumers and society at large. Market integration and price signal are obvious solutions as they would incentivise investments when necessary while increasing competition. More challenging is to address the competitiveness gap of most of new low carbon technologies. The carbon price is expected to orient investments towards clean technologies. However, its low level might not be sufficient to trigger these investments. Any other form of interventions would need to be designed in a way that would not weaken the wholesale market price signal.

In this context, i.e. during the transition to a decarbonised system, three strands of market arrangements could be explored:

- Reinforcing the price signal through scarcity pricing
- Reinforcing the price signal to orient investments in clean technologies through the carbon price
- Continuing European Market Integration to reduce market fragmentation and benefit from economies of scale and scope

Reinforcing the price signal through Scarcity pricing

Market prices, if not restricted, signal the market value of investments according to the need of the system. When investments are needed in order to cope with sudden demand or supply variations, prices will be allowed to increase during these times thereby indicating to potential investors the need, through scarcity prices, for solutions with the right characteristics (e.g. flexible power plants, demand response, storage).

([68]) Mature technologies such as onshore wind become competitive on the market under the transition phase.
([69]) Ben Caldecott (2014)

Limiting the price signal ([70]) undermines the capability of the market to generate scarcity prices, thereby limiting the rents that are required to cover the total costs of investments. This leads to a shortfall of revenues to finance new generation investment. Higher price variability is also important for demand response, as it acts as an incentive for consumers to become active during critical periods, while also incentivising the use of storage.

Wholesale prices could therefore be allowed to reflect consumers' willingness to pay and to value investments according to the needs of the system in order to ensure welfare maximisation. An indicator for this willingness to pay is the Value-of-Lost-Load (VOLL). Accurately estimating VOLL is challenging as it depends on multiple factors such as the type of customer affected, regional economic conditions and demographics, time and duration of outage, and the structure of economic activities etc. ([71])

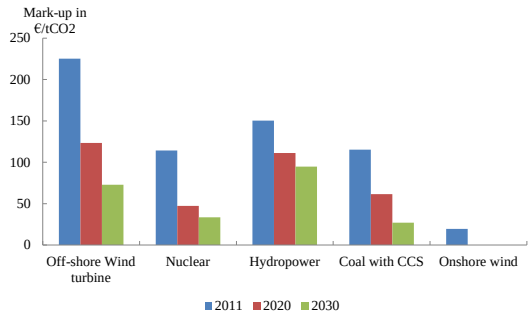
Reinforcing the price signal to orient investments in clean technologies through the carbon price

Investment in electricity is expected to play a fundamental role in the decarbonisation of the economy. The external costs of low carbon technologies is lower than that of fossil fuels and the market price should be able to reflect the overall different social costs of the technologies. The carbon price changes the relative costs between technologies (see Chapter II.2) and it helps to reduce emissions in a cost effective way. Hence, a sufficiently high carbon price would induce a switch to cleaner energy sources (i.e. switch from coal to gas and/or renewables).

Achieving high levels of decarbonisation in the power sector requires a portfolio of low carbon technologies. Several of these key technologies will not yet have reached a sufficient cost performance during the transition phase to generate enough revenues to cover their total costs. The CO2 price in the ETS will increase the cost of fossil fuel based technologies, and thereby contribute to cover the relative price differential of less mature low carbon technologies. It improves the competitiveness of low carbon technologies, and thus supports the energy transition. The recently agreed reforms of the ETS as of 2020 are expected to strengthen the carbon price signal (see Box III.2.1).

The need for additional price mark-up will diminish over time as the competitiveness of low carbon technologies is improved. A higher CO2 price in the ETS, which is likely in the long run, would also contribute (graph III.2.1). Mature technologies such as wind on-shore will not require additional support towards 2020. For less mature technologies, the additional CO2 price required by 2020 would range from 50 to 150 EUR per tonne of CO2 on top of the 20 EUR/tCO2. By 2030, the mark-up is reduced for most of the low carbon technologies due to learning effects. The price differential ranges from 20 to a bit more than 50 EUR/tCO2 on top of the CO2 price assumed in the reference case. These estimates are only indicative and should be read as an order of magnitude.

Graph III.2.1: **Estimated mark-ups in EUR/tCO2 for low carbon technologies under a marginal price regime**



Source: SETIS (2015), Own calculation

Continuing European Market Integration

Market integration is fundamental to ensure optimised and cost-effective investments for the energy transition. The interconnections contribute to a better utilization of existing transmission infrastructure and help to reduce the intermittency of supply induced by variable technologies, hence reduce price volatility. The increase in the size of the energy market also reduces the need for investment in back up generating capacity and

([70]) It is noted that it is not only a question of technically limiting the price signal. Fear of investors of future regulatory intervention may prevent also high prices.
([71]) LEI (2013)

Table III.2.1: **Dispersion* in the EU electricity sector: price and market support**

	2008	2009	2010	2011	2012	2013	2014
Market support							
Renewable (excl. Hydropower)	99%	83%	84%	96%	82%	-	-
Electricity retail							
Industry (excl. Taxes) - consumption 500-2000 MWh	27%	24%	27%	29%	33%	30%	30%
Industry (excl. VAT) - consumption 500-2000 MWh	26%	23%	25%	27%	31%	28%	29%
Households (excl taxes) - consumption 2500-5000 kWh	25%	24%	22%	23%	27%	26%	27%
Households (excl. VAT) - consumption 2500-5000 kWh	31%	29%	27%	29%	30%	28%	31%
Electricity Wholesale							
Spot prices	19%	16%	15%	11%	21%	17%	20%
CWE Region	3%	5%	3%	2%	5%	12%	9%
Nordic region	11%	5%	4%	3%	11%	4%	11%
SWE region	6%	1%	0%	2%	1%	1%	2%

* Price dispersion is measured by the coefficient of variation (standard deviation divided by the mean).

CWE region is composed of Austria, Belgium, France, Germany and the Netherlands. Nordic region is composed of Denmark, Finland; Norway and Sweden. SWE region is made of Portugal and Spain
¨Note: Dispersion is measured by the coefficient of variation. The higher the coefficient, the higher the dispersion across Member States.
Source: Platts, Ecofys, Eurostat

provides greater liquidity of wholesale markets. Finally, it increases competition among generators ([72]).

The expected benefits of market integration translate into cost and price reduction for consumers. Increased competition is expected to decrease mark-ups, which translates into lower prices. Empirical analysis shows that market opening and competition appear to have significant downward effects on consumer prices (both households and industry) ([73]). In addition market integration contributes to lowering costs. According to some estimates, the net economic benefits from the completion of the internal market mainly refers to cost savings ([74]) and ranges from 13 to 40 billion Euros per year by 2030. ([75]) The basis for these estimates is a higher level of market integration than today through market coupling, that remains based on national self-sufficiency with only short term arbitrage.

Price convergence is another expected outcome of market integration as domestic and foreign prices should progressively equalise according to the most efficient supplier ([76]). Hence, the degree of price convergence is used as a good indicator of market integration. However, in the case of electricity, national factors such as the energy mix play an important role and will influence the resilience of economies to external price shocks. Despite these limitations, in well-functioning markets, the convergence of retail price should mirror the convergence of wholesale prices.

Electricity wholesale market exhibits low price dispersion. The dispersion of the day-ahead wholesale price in thirteen European power exchanges ([77]) was about 20% in the 2008-2014 period. The day-ahead price convergence is even higher within the seven regional markets launched in 2006 by the European regulators, with price dispersion levels below 10% ([78]) (Table III.2.1).

Retail price dispersion has increased between 2008 and 2014 for industrial customers and households. It is also higher than for the wholesale market, which can be explained by the fact that taxes and levies are managed at national level. Nevertheless, price dispersion remains higher even when taxes and levies are excluded, indicating that the relative higher dispersion of retail prices can be attributed to other factors than the fragmentation of the wholesale market (Table III.2.1).

([72]) ECF (2012)
([73]) European Commission (2014 b).
([74]) E.g. fuel costs, annualised generator capital costs, and annualised transmission capacity capital cost
([75]) Study commissioned for the Commission. Booz & Company (2013)
([76]) European Commission (2007), Kalantzis and Milonas (2010)
([77]) APX, BPX, EPEX, EXAA, ELEXON, NordPool, OTE, PolPX, DESMIE, GME, OMEL, OPCOM, OTE
([78]) Seven regional markets defined as Central-West, Northern, the United Kingdom and Ireland, Central-South, South-West, Central East and Baltic. Further price convergence is expected due to the Multi-Regional Coupling initiative that started in 2014 and covers 19 countries in March 2015. http://www.epexspot.com/en/market-coupling

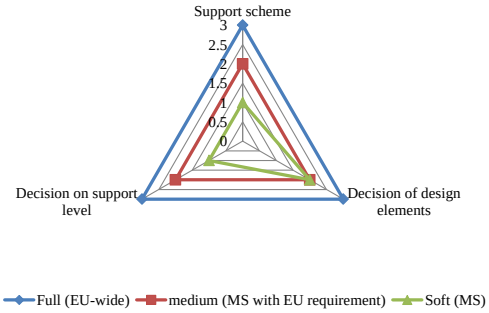
By contrast, the high dispersion of public support reflects the fragmentation of the market (Table III.2.1). A large part of the incentives for investments in security of supply and decarbonisation are promoted through public support within national borders. The dispersion shows consistent high levels from 2008 to 2012, reflecting the management of these schemes at national level.

2.2.2.1. *Instruments*

Considering the long life time of energy investments, the long term evolution of the economics of the power system should be accounted for when selecting market arrangements in the short to medium term. In particular, the decrease in market prices due to the increased penetration of low carbon technologies, as described under section III 1.1, is expected to intensify as European power systems complete their decarbonisation process. This can be foreseen to have a strong impact on market revenues.

Reinforcing price signal and market integration are a way to drive further the energy transition in a cost effective way. The different strands of market arrangements can be implemented in different ways. Scarcity pricing could be implemented, for instance, by setting price caps at VoLL or implementing scarcity pricing through Operating Reserves ([79]). Similarly, different degrees of harmonisation could be considered regarding the Europeanisation of market interventions (Graph III.2.2). For instance, under the full harmonisation option, design elements of low carbon technology market support or capacity remunerations schemes such as eligible technologies, capacity cap, support and duration levels, operating rules would be decided and implemented at EU level. The minimum harmonisation option is similar to the approach currently undertaken through the State Aid guidelines for environment and energy. In this case, all the design elements and operating rules of the schemes remain determined at national level. However, they could follow guidelines at EU level that also impose minimum requirements such as cross-border participation, competitive allocation of support, competition between technologies, and requirements to ensure beneficiaries are integrated into the market.

Graph III.2.2: **Degree of harmonisation of national market intervention**



Source: European Commission

R&I support and market pull measures need to be synchronised to effectively unlock the cost reduction potential of less mature low carbon technologies, flexible solutions and demand services. Relying on market based instruments is critical in this period of transition in order to ensure that investments are guided by the specific needs of the system through the indication of the price signals. This will give benefits from competition to keep cost in check. Other gains include promotion of innovation in technologies, services and business models.

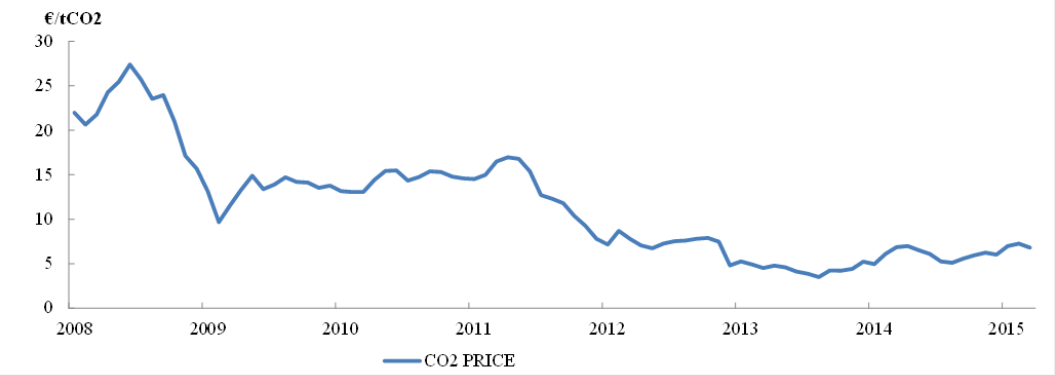
([79]) William W. Hogan (2013)

Box III.2.1: **Reforms in the Emission Trading Scheme**

The objective of the Emission Trading System (ETS) is to achieve cost-effective emission reduction through internalisation of external cost of CO2-emissions through a cap and trade of permits. The cap on the total emissions, in the form of a given number of allowances creates scarcity in the market and allows the market to set the equilibrium price. Emitters and other participants in the system can buy and sell allowances as they require, under the constraint that each emitter has enough allowances at the end of the year to match its emissions during the year. The ETS is in operation since 2005 and currently operates in 31 countries - the 28 EU Member States, Iceland, Liechtenstein and Norway. The industrial activities that are covered by the system include power stations, combustion plants, and energy intensive manufacturing. As of 2013 internal flights are also covered. The ETS currently accounts for about 45% of EU's total greenhouse gas emissions.

The trading of allowances in the ETS has been divided in different phases under different rules. The current phase started in 2013 and will last until 2020. It entailed substantial reforms of the allocation of allowances. As of 2013, the allocation is determined directly at the EU-level and the default method is auctioning. Allowances are auctioned under common rules, with the revenues going to Member States according to an agreed distribution key. Full auctioning is gradually introduced in a linear manner reaching 100% of auctioning by 2027. The legislation explicitly specifies that electricity producers will have to purchase the required allowances in auctions or on the secondary market. As wholesale power prices are determined by the marginal cost, this implies that the CO2-price will increase the power price on the wholesale market whenever a fossil fuel technology is operating at the margin. Hence, it will contribute to create room for inframarginal rents to those technologies with lower operating costs than the marginal one.

Graph 1: **Prices on CO2, 1-month forward, monthly averages**



Source: Ecowin, Bloomberg

In the first half of 2008, CO2-emission allowances traded in the range of €20-30/tCO2. In the subsequent period (2009 – first half of 2011), following the on-set of the economic crisis with a fall in demand, prices hovered around €15/tCO2. An increased use of international credits also contributed to the supply, in addition to the predetermined annual supply as given by the cap. Carbon prices continued to fall in the second half of 2011, and since then it has consistently traded below €10/tCO2. As the supply of emission allowances is determined by the cap, the supplied quantity does not react to a fall in demand.([1])

Empirical analysis ([2]) shows that the recent economic crisis has contributed to lower the demand of allowances, thereby contributing to a large part of the ETS market imbalance, with a surplus of 2.1 bn

([1]) See COM(2012)652. A number of regulatory provisions related to the transition between the trading periods also contribute to the build-up of oversupply of allowances in 2011, e.g forward selling related to the NER300 programme and auctioning of left-over allowances from the phase 2 new entrants reserve.
([2]) European Commission (2014a).

(Continued on the next page)

Box (continued)

allowances, and the decrease in price. However, the European carbon market is not isolated from other shaping factors such as, among other drivers, the fuel switching behaviour of the conventional power producers and the renewable penetration. The success of renewables in Europe has, by reducing greenhouse gas emissions, contributed to the oversupply of allowances and thus the decrease in the carbon price. The results show the importance of economic factors in driving carbon prices, but highlight also the interplay between energy and climate policies. The discussions on the ETS institutional set-up have also made the market participants and the market more sensitive to regulatory and institutional innovations.

The decline in carbon prices has triggered several policy responses. A political agreement to delay the auctioning of allowances, the so called **backloading**, was reached in 2014. It delays the auctioning of a total of 900 mn of allowances over three years, i.e. in 2014, 2015 and 2016, and provide for the auctioning of them in 2019 and 2020.

The situation on the ETS-market was also one factor pointing to the need of a well-defined policy beyond 2020. A political agreement was reached in the European Council in October 2014 on the 2030 energy and climate policy framework. The agreement sets a -40 % greenhouse gas emission reduction target for the EU by 2030 and reaffirms the role of the ETS as the main instrument in the EU to reduce carbon emissions in the industrial sector by 43%. In order to achieve this cap, **the annual emission reduction factor is increased to 2.2% per year** as of 2021 (compared to the existing factor of 1.74%). As a result, the additional supply of allowances that is auctioned each year from 2021 and onwards will shrink faster than under the current rules.

A proposal for a **Market Stability Reserve** was also put forward as part of the 2030 policy framework and was agreed in May 2015. A reserve of allowances is to be established in 2018 and be operational from 1 January 2019. Allowances are to be placed in or released from the reserve if the amount of allowances circulated on the market is beyond a certain threshold. The system is set-up to be autonomous so that no policy interventions would be needed to determine these transfers to and from the reserve. The agreement also places the backloaded allowances in the reserve ([3]).

As described in this report, the CO2-price influences the electricity wholesale price when fossil fuel technologies operate on the margin. As such, it is an important factor influencing power prices and the profitability of the power generation. Commission does not provide projections for the carbon price in relation to the various proposals reforming the ETS, but price projections are made in the context of the modelling of the energy system with PRIMES in combination with other models

Table 1: **Carbon price projections**

	2020	2025	2030	2050
Energy trends to 2050, 2013 reference	€$_{2010}$10/tCO2		€$_{2010}$35/tCO2	€$_{2010}$100/tCO2
IA 2030 Policy package: 40% GHG-reduction			€$_{2010}$40/tCO2€	

Source: European Commission

These price projections point at considerably higher prices than the current price level in the market for emission allowances (figure 1). The current oversupply on the carbon market is keeping the price lower than has been expected. The structural measures listed above have been undertaken to support a better balanced market, but it remains to be seen whether these measures would be sufficient to achieve a price level that can better incentivise long-term investments in emission abatement.

The Carbon Market report from 2012 outlines other possible structural reforms of the ETS. One of them is the extension of the scope of the ETS, which could give a more uniform carbon price signal across the economy and thereby allow for a more cost-efficient distribution of the abatement efforts. The inclusion of sectors that are influenced less by the economic cycles could also contribute to stabilise the demand and supply of emission allowances. The emissions of the EU ETS decreased in 2009 by more than 11%, while

([3]) Any unallocated allowances at the end of phase 3 in 2020 are also to be placed in the reserve.

(Continued on the next page)

Box (continued)

the corresponding reduction for the sectors outside the ETS amounted to 4% ([4]). The main sectors that remain outside the ETS include transport and residential heating, which could bring in another 34% of emissions ([5]), in comparison with the current coverage of slightly more than 45% .An extension of the ETS would cover a higher share of the overall greenhouse gas emissions and would therefore require an adjustment of the number of allowances in the ETS, and hence its cap. The adjustment of the coverage of emitters and the cap would determine the impact on the overall supply-demand balance on the market. An extension would enlarge the market and make it more liquid. This could contribute to improve price discovery and price formation on the market, and hence potentially improve the functioning of the ETS market. However, this will also depend on how the obligation to report emissions are organised. The emitters in the sectors currently outside the ETS are often small and numerous, while the ETS covers large-scale installations. This can be addressed by putting the obligation to report on emission upstream on oil or gas distributors. It remains important to ensure that this is organised in a manner that facilitates a competitive market. Such a reform would obviously require extensive analytical work to assess the potential economic impacts as well as links to and consistency with other policies.

([4]) European Commission (2012)
([5]) European Environmental Agency (2014)

2.3. CHALLENGES FOR INVESTMENTS AND OPTIONS UNDER DECARBONISED POWER SYSTEMS (DECARBONISED PHASE)

2.3.1. Challenges

In a future decarbonised system, the effectiveness of the market framework can also be assessed through the incentives investors get from market signal, the degree of public intervention and the level of competition. Compared to stage 2, most of technologies are expected to have become competitive.

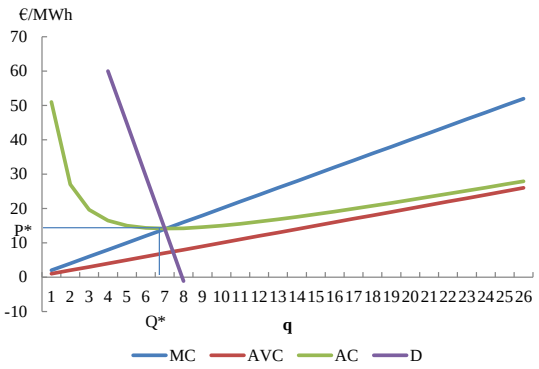
The cost structure of the technology mix of decarbonised power systems will exhibit decreasing average cost trend due to fact that low carbon technologies have low variable costs and fixed costs constitute more than 2/3 of the overall costs (see chapter II.2). Nonetheless, conventional capacity will be needed to meet high demand and account for resource availability and the lack of firmness of some low carbon technologies. This will result in merit order curves with steep ends.

When technologies display decreasing average costs and positive fixed costs, assuming perfect competition, marginal pricing may default to produce sufficient revenues to cover the fixed costs of the technologies ([80]). The main reason as discussed under Part III.1.1 and shown under graph III.2.4 is that the marginal cost never crosses the average cost, hence pricing at marginal cost would lead to an economic loss for generators. This is a noticeable difference with a conventional power system as shown in Graph III.2.3, which exhibit increasing average costs that allows for an equilibrium to be found between the marginal cost, average cost and demand. This revenue shortfall will be strongly dependent on the frequency and intensity of price spikes in the future. However, in the decarbonised phase, it is uncertain if these price spikes will be feasible and enough or allowed to be high enough to recoup the fixed costs.

Under the decarbonised phase, the decreasing level of CO2 emissions of the technology mix will reduce the social cost of the power system. . In a decarbonised system which mainly applies clean technologies on the margin, the carbon price will have less influence on wholesale market prices. As a result, the role of the carbon price to generate infra-marginal rents for low-carbon technologies can be expected to be reduced.

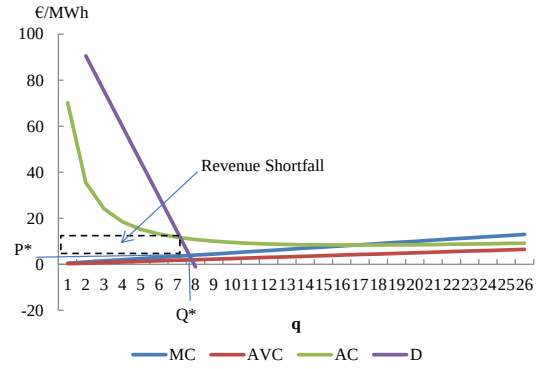
([80]) Varian R. Hal (1996), Baritaud, M. (2012), Finon D. (2013)

Graph III.2.3: **Cost structure of the technology mix under conventional power system**



Source: European Commission

Graph III.2.4: **Cost structure of the technology mix under the decarbonised phase**



Source: European Commission

2.3.2. Different forms of market arrangements

As in the previous phases, the effectiveness of the market framework needs to take account of the price signal for an investor, the degree of public intervention and level of competition, while maximising the overall social welfare. In the decarbonised phase, low carbon technologies are expected to be competing on the market. Investments in a market environment characterised by technologies with high fixed costs and low variable costs will depend on the price signals and their ability provide remuneration to compensate for the structural revenue gap induced by this cost structure and uncertainty related to price spikes.

In this phase, the transition is assumed to have been successfully completed, and the objective of market arrangements would be to ensure security of supply in the short and long run. There are currently few markets in the world which are dominated by low carbon technologies, but their experience shows that ensuring investment in the long term is a crucial issue (see box III 2.2). Any market arrangements should be able to deliver long term investments without relying on state interventions or guarantees.

Box III.2.2: **Low carbon technologies and market designs: the experience in South and Central America**

The importance of hydropower in the electricity mix of South and Central American countries provides real experience on the influence of low carbon technologies on electricity market designs. Hydropower is the dominant supply source in the region. It represented in 2011 52% of the total installed capacity or 68% of the energy produced in 2011([1]).

South America has carried out significant reforms of its power markets over the last two decades. In 1982, Chile started a first wave of market reforms in the region, with the liberalisation and privatisation of its power sector. It was followed by several countries in South America such as Argentina (1992), Peru (1992), Colombia (1993) and Brazil (1994) and across the globe, for instance in the EU in 1996 [2]. The basic principles of these reforms was to rely on competition and on spot prices in the short-term ("spot") wholesale market to drive investments in electricity supply in addition to the use of forward contracts to hedge price and market risks ([2]).

However after less than a decade, it became apparent that investments were lagging behind to maintain security of supply and to cope with the fast expansion needs of the power sectors of these countries. For instance, electricity rationings occurred in Chile 1998-1999 and Brazil in 2001-2002 while electricity cross border supply was interrupted between Argentina-Brazil and Argentina-Uruguay ([3]). One of the main reasons often cited for these crises were the severe drought that reduced the outputs of the dominant hydropower plants and the short term contracting arrangements that created insufficient incentives to invest in new generation ([4]). It was observed that prices under such power systems masked structural supply problems, resulting in price increases only when the power system is about to fail, not allowing enough time to make investments. ([5])

As a result, these countries implemented a new wave of reforms based notably on the implementation of auctions for long-term contracts to incentivise investments. The key point of these reforms was that competition shifted from the spot market - competition in the market - to the long term contract market - competition for the market ([6]).

In 2004 Brazil launched a new market framework with the creation of two energy trading environments:

- A regulated Contracting Environment (RCE) where a pool of distributors buys power from generators in public auctions

- And a Free Contracting Environment (FCE) where free consumers, traders and generators can freely negotiate their contracts.

The Brazilian regulation imposed to distribution companies that 100% of their forecasted demand is covered with long-term contracts with generators and those contracts are covered by firm energy certificates (FEC). There exist two main types of auctions in Brazil: auctions for existing capacities and auctions for new capacities. Contracts for existing capacities aim at delivering energy one year ahead (A-1). These contracts can have durations between 5 to 15 years. Contracts for new capacities are contracts for energy delivery in 3 (A-3) or 5 (A-5) year time. The reason is to allow for enough time for the construction of a power plant. The durations for these contracts for new capacity range from 15 years (thermal power plants) to 30 years (hydropower plants). Adjustment auctions are also performed to cater for the uncertainties to declare its demand years in advance. These contracts are for delivery 4 month ahead with a duration of 1 to 2

([1]) T. J. Hammons (2011)
([2]) T. J. Hammons (2011)
([3]) Paolo Mastropietro (2013)
([4]) Castalia Strategic Advisor (2013)
([5]) T. J. Hammons (2011)
([6]) T. J. Hammons (2011)

(Continued on the next page)

Box (continued)

years. ([7]) ([8]) Although, the procurement scheme is centralised, i.e. all demand from the distributors are aggregated, this is not a single buyer model. The government does not interfere with the contracts nor guarantees payments. ([9])

Long-term auction mechanisms were also implemented in other countries, such as Chile in 2005 and Peru in 2006. In 2006, Colombia introduced reliability-options, which are firm energy obligations; a commitment from generators to produce firm energy during scarcity periods. ([10]) ([11])

In central America, Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua and Panama have built since 1996, the central American Electrical Interconnection System (SIEPAC), a 1 800 km transmission infrastructure that inter-connects the energy systems of these six countries, as the basis of the Regional Electricity Market (MER). Following the terms of the treaty creating SIEPAC, the MER is a 7th regional market that allows electric power across the existing six markets. On 1 June 2013, the MER regulations enabling regional transactions came into effect. To support the MER functioning, several institutions have been created, including the Regulatory Commission on Electrical Interconnection (CRIE) located in Guatemala, the Operating Agency Network (EOR) in San Salvador, and the Governing Board of the MER, which has an Executive Secretariat based in Costa Rica ([12]).

([7]) Castalia Strategic Advisor (2013)
([8]) Luiz T. A. Maurer (2011)
([9]) T. J. Hammons (2011)
([10]) T. J. Hammons (2011)
([11]) Paolo Mastropietro (2013)
([12]) IDB FACT SHEET (2013)

Three separate strands of market arrangements could be further explored in view of a future fully decarbonised power system:

- Reinforcing the price signal through scarcity pricing
- A wholesale market complemented by an EU wide capacity market
- An EU wide market for long term contracts based on average cost pricing

Reinforcing the price signal through scarcity pricing

Reinforcing the price signal through scarcity pricing will become essential in decarbonised power systems as the high share of low carbon technologies coupled with high demand response will tend to result in very low prices during most part of the time. Prices should then be allowed to indicate accurately and visibly through scarcity prices the specific needs for the proper functioning of the power system in the short run for periods of scarcity (e.g. to trigger demand response, storage and other forms of flexible solutions) and in the long run (e.g. to foster investments).

A wholesale market complemented by an EU wide capacity market

The main feature of such a market arrangement would be to develop, besides the wholesale market, a market for capacity where producers would contract out and be able to get a return on the availability of their capacity. Under this configuration, the wholesale market is kept to ensure efficient short-term dispatching and as an indicator of the real time value of each energy assets for signalling specific investment gaps (e.g. in peak or base load, flexible etc.).

An EU wide market for long term contracts based on average cost pricing

The main feature of this market arrangement would be to shift competition from the spot market - *competition in the market* - to a long term contract market - *competition for the market*. Under this configuration, suppliers are required to cover their forecasted demand through long-term contracts with low carbon generators and flexible solution providers. In exchange, generators receive long term contracts with conditions and terms allowing them to recover the total costs of their investments. The short-term

market in this context acts as a balancing market to settle imbalances arising from contractual differences between generators and suppliers.

Some regions of the world such as Latin America, where power systems are dominated by low carbon technologies, namely hydropower, have adopted markets for long term contracts. One of the main reasons often cited for this change in market structure is related to the effect of hydropower plants ([81]) on price signals. Under power systems dominated by hydropower, it was observed that prices mask structural supply problems. As a result, price increases only when the power system is about to fail, for instance due to a drought that reduces the outputs of hydropower plants, which does not allow enough time to make investments. (See box III.2.2). Such market form shows noticeable difference with today's EU markets as, in particular, it replaces the wholesale market and there is no carbon market.

2.4. CONCLUDING REMARKS

EU power systems have entered an era of profound changes. The cost structure of low carbon technologies is increasingly influencing the price formation on the wholesale market, and thereby the incentives to invest in energy assets. Therefore, there is a need to ensure that market designs are not carved in stone but evolve with the energy transition.

In the short to medium term, **the critical challenges are** (i) to trigger investments in low carbon technologies while making public support more focused and market-based, (ii) to avoid (structural) over/under capacity, while investing in flexibility solutions and (iii) to foster the competitiveness of low-carbon technologies. For this, scarcity pricing, reinforcing CO2 prices, and continuing the market integration are options to strengthen price signals to drive investment and improve the efficiency of the current market framework. Hence, these options are solutions that can improve the market functioning both in the shorter and longer term.

In the long term, it is uncertain whether wholesale prices based on existing market arrangements will be able to provide the revenues necessary to cover the total costs of investments and thereby incentivise investments in low-carbon generation. In this context, the market design might need to evolve, which could entail, for example, scarcity pricing, European efficient and integrated markets, and, when needed, an increasing reliance on long term contracts or some form of capacity markets. On the latter option, it remains unclear to which extent the market itself, under current arrangements, can cater for this development e.g. through the development of new forms of contracts. These changes of the market frameworks can be expected to be needed in the next decades. Considering the inertia of the energy system and life time of energy assets, this calls for starting a reflection already now on these long term issues related to the electricity market design at the EU level.

([81]) Hydropower is the dominant supply source in the region. It represented in 2011 52% of the total installed capacity or 68% of the energy produced in 2011. [1]

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GLOSSARY

Adequacy: power generation (or supply) adequacy can be defined as the ability of the system to meet the aggregate power and energy requirement of all consumers at virtually all times.

Ancillary Services: are those services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission service provider in accordance with good utility practice. They refer to a range of functions which TSOs contract so that they can guarantee system security. These include black start capability (the ability to restart a grid following a blackout); frequency response (to maintain system frequency with automatic and very fast responses); fast reserve (which can provide additional energy when needed); the provision of reactive power and various other services. Some are serviced through markets, simultaneously cleared with energy markets; others are serviced through cost-based mechanisms and do not have markets.

Balancing refers to the situation after markets have closed (gate closure) in which a TSO acts to ensure that demand is equal to supply, in and near real time.

Base load plants: they are those plants that run continuously all year round with a steady load. In the EU they are the lignite fired conventional plants, gas fired combined cycle generation, and, wherever possible, nuclear plants.

Baseload: it is the minimum basic amount of electricity needed to meet demand.

Capacity factor: the ratio of the total energy generated by a generating unit for a specified period to the maximum possible energy it could have generated if operated at its maximum capacity rating for the same period (NERC).

Conventional plants: the term refers to the non-low carbon technologies, based on fossil fuels (lignite, hard coal, natural gas, oil). They usually constitute the mid-range and peaking plants.

Capacity mechanism: capacity mechanisms in general reward capacity providers for their ability to deliver electricity when needed, rather than the actual delivery of electricity, even though various models exist. A capacity market does not need price spikes to induce investments.

Demand response: refers to a mechanism that enables consumers to change voluntary their consumption pattern in response to market signals.

Dispatchable generation: is electricity produced by those generating plants that can be turned on or off, or can adjust their output at the request of the power grid operators. This is not the case, for example, with some types of base load generation like nuclear power, which can't easily adjust its generation on demand; or some renewable sources like wind power, which can't be controlled by operators. Dispatachable generation is used in order to (but is not limited to) meet peak demand.

Firm capacity is the amount of energy available for production or transmission which can be (and in many cases must be) guaranteed to be available at a given time. Of the firm capacity available, the actual energy guaranteed to be available is referred to as firm energy. Nonfirm energy, in contrast, refers to all available energy above and beyond firm energy.

Flexibility is the ability to reconcile volatile consumption and volatile generation. This implies a capability (e. g. ramping), coupled with a high level of controllability and reliability / availability of the power system.

Gate closure: the moment when contracts are frozen. After gate closure, no trading is allowed anymore for the day-ahead. At this point, parties are expected to adhere to the physical data submitted to the System Operator and to the contracted volumes submitted before Gate Closure.

Imbalances: an imbalance occurs whenever there is a mismatch between the quantity of electricity traded on the spot (day ahead) market and the actual generation/consumption when contracts are executed. For example, generators may physically produce more or less energy that they have sold and suppliers (through their customer demand) may physically consume more or less energy than they have purchased. These surpluses and deficits are referred to as imbalances.

Inframarginal rent: inframarginal rent refers to the rent earned by all generation sources utilized to serve demand that have lower marginal costs than the marginal generation source. The final price for electricity will be, in fact, the marginal cost of the last generator needed to meet demand, and all other generators in the merit will be able to earn the difference between their marginal costs and the final electricity price.

Load factor: it can be defined as either: (i) the number of hours of electricity generated over the year divided by the total number of hours in the year; or (ii) the amount of generation (in MWh) produced during the year divided by the theoretical maximum production during the year.

Load: is the total electricity demand.

Mega Watt (MW): is the most common unit of measure of electricity. It corresponds to the power needed to light approximately 750-1000 homes.

Peaking plants: plants that are characterised by low fixed costs and high marginal costs. They also have rather long booting periods.

Ramp up: in electricity jargon it means "increase output".

Scarcity rent: it is the rent earned by electricity generators during scarcity periods, that is: periods when demand cannot be met by increased supply. The electricity price during scarcity periods can increase dramatically.

Spin: is the increase in output that a generator can provide/back down in a very short period (usually 10 minutes).

Annexes

ANNEX 1

Investment drivers: variables description

Table A1.1: **Investment model**

Variables	Acronyms	Description	Unit	Source	Sample
New Additions in Installed Capacity		Change of installed capacity of nuclear, combustible fuels, biomass and hydro power plants	MW	Eurostat	EU28, 2005-2012
		Energy-Specific Factors			
Electricity Wholesale Price (Spot)	spot	Baseload electricity prices	EURO/MWh	Platts, Bloomberg	EU*, 2005-2012
Concentration Ratio of main Generators	cumshare	Cumulative market share of main generators	(%)	Eurostat	EU28, 2005-2012
RES share	ShRES	Share of the installed capacity of Solar, Photovoltaic and Wind in the total electricity installed capacity of the system	(%)	Eurostat	EU28, 2005-2012
Reserve Margin	resmargin	Firmed capacity over peak load	(%)	Eurostat, ENTSO-E	EU28, 2005-2012
Dummy for Capacity Mechanisms		Binary variable that takes the value of 1 when there is a support mechanism for generators	(0-1)	Commission Services	EU28, 2005-2012
		Macroeconomic Factors			
Electricity Demand	eldem	Electricity demand	TWh	Eurostat	EU28, 2005-2012
Interest Rates	iln	Interest Rates in nominal terms	(%)	AMECO	EU28, 2005-2012
Dummy for Quality of Regulation		Binary variable that takes the value of 1 when the score of the quality of regulation is above the mean of all the MS	(0-1)	World Bank	EU28, 2005-2012

* The data concern 13 MS (Austria, Belgium, Germany, Denmark, Greece, Spain, Finland, France, Italy, The Netherlands, Portugal, Sweden, United Kingdom) and their period varies based on the year of each market establishment

Source: European Commission

ANNEX 2
Power price drivers methodology and data description

The relationship between electricity wholesale prices, electricity demand, imports, exports, renewables and other external factors (Brent oil, Coal-ARA, Natural Gas-TTF and carbon prices) on a monthly basis over the period September 2007- July 2014 is examined for 13 EU day-ahead electricity markets (Austria, Belgium, Germany, Denmark, Greece, Spain, Finland, France, Italy, The Netherlands, Portugal, Sweden, United Kingdom). The objective is to see whether there is a long term relationship between some of these variables and how they relate to each other. For this purpose, a panel analysis is employed, consisting of three main steps: First, the order of integration of all variables is tested. Second, after having determined the order of integration in the series, heterogeneous panel co-integration tests were used to investigate whether a long term relationship between the variables in question exists. Third, in case of a long term relationship, a panel based error correction model is developed in order to identify the short and long-run causal relationship between the variables examined.

A2.1. METHDOLOGY

Panel Unit Root Tests

A number of unit root tests have been developed for establishing the order of integration of series in a panel context. The most common of them are Levin, Lin and Chu (2002), Breitung (2000), Im, Pesaran and Shin (2003), Fisher-type tests using ADF and PP tests-Maddala and Wu (1999), Choi (2001), and Hadri (2000). These tests present many similarities with the unit root tests used on single series.

The basis of panel unit root test is to identify if there are restrictions on the autoregressive process across cross-sections or series. This can be tested based on the following AR(1) process for panel data:

$$Y_{It} = a_i + \rho_i \, Y_{t-1} + \delta X'_{it} + e_{it} \qquad (1)$$

where i stands for cross-section units or series, that are observed over periods t.

The Xit represent the exogenous variables in the model, including any fixed effects or individual trends, ρi are the autoregressive coefficients, and the errors are assumed to be mutually independent idiosyncratic disturbance. If $|\rho i| < 1$, is said to be weakly (trend-) stationary. On the other hand, if |ρi|=1 then Yi contains a unit root.

For purposes of testing, two additional assumptions can be made. First, one can assume that the persistence parameters are common across cross-sections so that ρi=ρ for all. The Levin, Lin, and Chu (LLC), Breitung, and Hadri tests all employ this assumption. Alternatively, one can allow ρi to vary freely across cross-sections. The Im, Pesaran, and Shin (IPS), and Fisher-ADF and Fisher-PP tests are of this form.

The results of the LLC, IPS, Fisher-ADF, and Fisher-PP, Breitung and Hadri panel unit root tests, for each of the variable, are presented in Table A2.1. The test is performed both for the level and first difference of electricity wholesale prices (PSPOT), electricity demand (ELDEM), electricity imports (IMP) and exports (EXP), the share of RES in total electricity production (SHRES), the Brent crude oil (POIL), the Coal ARA (PCOAL), the natural gas-TTF (PNG) and the carbon prices (PCO2).

Table A2.1: **Panel unit root test results**

		H0: Non-stationarity					H0: Stationarity	
		Common process		Individual process				
		Levin, Lin & Chu t*	Breitung t-stat	IPS W-stat	ADF - Fisher	PP - Fisher	Hadri Z-stat	Heteroscedastic Consistent Z-stat
Level								
	PSPOT	-0.161	-5.44***	-6.33***	90.414***	108.24***	3.87***	3.43***
	ELDEM	57.24	-891	-0.117	41.77**	182.13***	-0.78	4.10***
	IMP	-1.91**	-0.29	-8.375***	141.31***	172.13***	5.78***	4.301***
	EXP	-3.00***		9.84***	173.59***	186.37***	7.90***	5.19***
	SHRES	-9.12***	2.56	-9.75***	178.31***	251.76***	4.40***	7.81***
	BRENT	-2.06**	-6.89***	-5.08***	65.84***	26.36	3.28***	3.28***
	co2	0.52	-1.82**					
	PCOAL	1.20	-6.94***				1.69**	1.69**
	PNG	3.17	1.59				5.89***	5.89***
First Differences								
	Spot	-21.97***	-12.03***	-26.34***	-353.15***	-626.66***	-1.18	-1.15
	ELDEM	166.46***		-12.83***	194.54***	315.61***	-3.27	-1.62
	IMPORTS	35.88***		-14.30***	251.17***	272.22***	-2.03	0.03
	EXPORTS						-2.07	-1.51
	SHRES	2.46***		-17.75***	292.90***	557.56***	-1.74	0.49
	BRENT							
	co2	12.57***					-2.38	-2.38
	PCOAL	-17.13***					-2.50	-2.50
	PNG	-38.89***	-25.58***				-0.47	-0.47

The optimal lag length was selected based on the SIC criterion. The null hypothesis is that the variable follows a unit root process, except for the Hadri Z-stat and the Heteroscedastic Consistent Z-stat. Probabilities for the Fisher-type tests are computed using an asymptotic Chi-square distribution. All other tests assume asymptotic normality. *, **, *** indicate significance at 10%, 5% and 1% confidence level.
Source: Commission Services

The tests are rather inclusive in levels regarding stationarity. The null hypothesis of a unit root cannot be rejected for Hadri tests for all variables and for the LLC and Breitung tests for some variables, including the wholesale electricity prices, electricity demand and imports, share of renewable and the carbon prices. Only the exports of electricity can be considered as stationary variable in levels. After taking the first difference of the first set of variables that found to be non-stationary, the tests indicate that the series become stationary at 1% confidence level. Thus, the results are fairly conclusive on regards first differences and indicate that these variables are non-stationary in levels, and become stationary only in first differences, which mean that they are integrated of order one or I(1).

Panel Co-integration Tests

After taking into account the results of the panel unit root tests, the next step involves the test for co-integration of the variables in question based on the heterogeneous panel co-integration techniques developed by Pedroni (1999) and Kao (1999), which allow for cross-sectional interdependence with different individual effects. Both have extended the Engle-Granger framework on co-integration analysis by adjusting the analysis in panel data. These tests are considered as improvements of conventional tests due to the increasing power of the panel co-integration tests (Rapach and Whohar, 2004). Pedroni (1999) proposes two types of residual-based tests for panel co-integration. The first type tests, including panel v-statistic, panel ρ-statistic, panel PP-statistic and panel ADF-statistic, provide within estimations and follow a standard normal asymptotically distribution. The second type tests, including the group r-statistic, the group PP-statistic and the group ADF-statistic, are also asymptotically normal distributed tests. Compared to the first type test, they provide between estimations as they pool the residuals for the between-group.

According to Pedroni (1999) the following general specification can be used to test for co-integration. It allows for heterogeneous intercepts and trend coefficients across cross-sections:

$$Y_{it} = a_i + \delta_i t + G'_{it} b \quad + e_{it} \qquad (2)$$

where i stands for cross-sections, t for time periods and αi and δi are individual and trend effects, respectively, Yit is the electricity wholesale price and Git is a vector of the other explanatory variables. Under the null hypothesis of no co-integration, the residuals eit will be I(1). The Kao test follows the same basic approach as the Pedroni tests, but specifies cross-section specific intercepts and homogeneous coefficients on the first-stage regressors. In addition, Maddala and Wu (1999) used Fisher's result to propose an alternative approach to testing for co-integration in panel data by combining tests from individual cross-sections to obtain at test statistic for the full panel.

Overall, it can be concluded that there is a panel long-run equilibrium relationship between the variables examined each time. Taking into account the non-stationarity property of all the variables and the aforementioned residual panel co-integration tests, the Pedroni's (2004), the Kao's (1999) and the combined Johanshen and Fisher tests were used to establish whether a long-run relationship exists.

Table A2.2 reports the within and between dimensions of the panel co-integration tests, the Kao's test and the Johanshen- Fisher panel co-integration test. The results of heterogeneous panel tests indicate that the null of no co-integration between variables in Model 1 and these of Model 2 can be rejected at the 1% significance levels in all tests. In fact, the combined Johansen and Fisher tests imply that there might be up to two co-integrating relationships among the variables of the two models. For both cases it seems that individual coefficients can be estimated when estimating the long-run relationship. Electricity exports were excluded from both models as they were not statistically significant, as well as the coal prices because there was indication of severe case of multicolinearity based on the variance inflation indicator and the coefficient of variance decomposition. Along the same lines, the variables of the Brent oil prices and the natural gas prices was decided not to be included in the same regression and this was the main reason for estimating two separate models.

Table A2.2: **Pedroni and Kao residual co-integration test results**

	SPOT, IMP, SHRES, CO2, ELDEM, PNG	SPOT, IMP, SHRES, CO2, ELDEM, POIL
	Alternative hypothesis: common AR coefs. (within-dimension)	
	Statistic	**Statistic**
Panel v-Statistic	0.13	-0.27
Panel rho-Statistic	-4.59***	-3.39***
Panel PP-Statistic	-6.52***	-4.64***
Panel ADF-Statistic	-7.17***	-4.66
Kao's test (ADF)	-3.35***	-5.17***
Johanshen Fisher-Trace Test	At most 2 - 74.03****	At most 2 - 59.71***
Johanshen Fisher-Max Eigen.	At most 2 - 54.29****	At most 1 - 85.36***
Alternative hypothesis: individual AR coefs. (between-dimension)		
Group rho-Statistic	-4.17***	-2.31**
Group PP-Statistic	-7.07***	-4.01***
Group ADF-Statistic	-7.65***	-3.59***

The null hypothesis for all the tests, except for the Johanshen-Fisher test, is that the variables are not cointegrated. Under the null hypothesis, all the statistics are distributed as standard normal distribution. *, **, *** indicate significance at 10%, 5% and 1% confidence level.
Source: Commission Services

Given these findings, two main estimators are used for estimating the cointegrating vector in a panel context, the Fully Modified Ordinary Least Square (FMOLS) estimators and the Dynamic Ordinary Least Square (DOLS) estimators. ([82]) The FMOLS estimator, proposed by Phillips and Hansen (1990), employs a semi-parametric correction to eliminate the problems caused by the long run correlation between the cointegrating equation and stochastic regressors innovations. The DOLS estimator, advocated by Saikkonen (1992) and Stock and Watson (1993), is a parametric approach that eliminates the feedback in the cointegrating system.

([82]) The FMOLS and DOLS are necessary because of the correlation between the error term and the lagged dependent variables in the panel VECM specification.

The long-run equilibrium is then estimated using the FMOLS and DOLS technique ([83]) (Table A2.3). Results of panel FMOLS and DOLS indicate that electricity wholesale prices are positively correlated with all the variables in both models, except for the share of renewables in the total electricity production. Almost all of the estimated coefficients are statistically significant at the 1% levels, implying that there is a strong long-run relationship between the variables included in the analysis based on both approaches: FMOLS and DOLS.

Table A2.3: **Panel FMOLS and DOLS long-run estimates (in logs)**

	MODEL 1		MODEL 2	
Variable	**Day-ahead prices**	**Day-ahead prices**	**Day-ahead prices**	**Day-ahead prices**
Carbon price	0.22***	0.22***	0.19***	0.19***
Natural gas price	0.42***	0.42***		
Share of renewables	-0.09***	-0.11***	-0.10***	-0.12***
Import	0.16***	0.16***	0.15***	0.18***
Electricity demand	0.23***	0.24**	0.44***	0.54***
Oil price			0.33***	0.39***
R2	65%	68%	51%	64%
Country Fixed Effects	YES	YES	YES	YES
Estimation Method	FMOLS	DOLS	FMOLS	DOLS

Note: *, **, *** indicate significance at 10%, 5% and 1% confidence level.
FMOL: Fully Modified Ordinary Least Squares
DOLS: Dynamic Ordinary Least Squares
Source: Commission Services

Panel Granger Causality Tests

Once a long-run relationship between the variables examined has been identified, this relationship is used to estimate a panel error correction model, with the same specifications as in the co-integration tests. This will indicate the direction of the causal relationship of the variables in question, both in the long and short-run. Thus, the residuals of the lon-run model (equation 2) are included as regressor in the dynamic error correction model, which is specified as follows:

$$\Delta Y_{it} = a_{1i} + \lambda_1 \, EC_{It-1} \quad + \sum_{k=0}^{q} \beta_{11ik} \Delta Y_{it-k} + \sum_{k=0}^{q} \beta_{12ik} \Delta G_{it-k} \; + u_{1it} \qquad (3)$$

Where Δ represents the difference operator, EC is the lagged error correction term derived from the long-run model (equation 2), αi,λi and βi are the coefficients, u is the error of the equations, Y represents the dependent variable each time, G is the set of the explanatory variables and k is the number of lags based on Schwarz information criterion.

The direction of the causal relationship will be determined by the results of the Granger causality test, after treating the panel data as one large stacked set of data. The only exception of the test is not letting the data from one cross-section enter the lagged values of data from the next cross-section. This method assumes that all coefficients are same across all cross-sections.

Taking into consideration of the residuals of the long-term equilibrium, a panel VECM model is used to estimate the direction of causality in the short and the long run. The results of the VECM with six simultaneous equations for the analysis of the causal ([84]) relationships for Model 1 and 2 are presented in Tables A2.4 and A2.5 below. The optimal lag structure of 13 and 11 months, respectively for Model 1

([83]) It is important to note again that the DOLS method has the drawback of reducing the number of degrees of freedom by including leads and lags in the variables studied, leading to less robust estimates. Hence, the DOLS estimation method is used to confirm the general trend and direction of the causality obtained by the FMOLS method.
([84]) The significance of causality tests are determined by the Wald F-test.

and 2, for the two relationships is chosen based on the Schwarz Information Criterion, in order to remove autocorrelation in the residuals.

Table A2.4: **Short run causality (Variables in first differences)**

		MODEL 1						MODEL 2					
	TO:	PSPOT	PCO2	ELDEM	IMP	SHRES	PNG	PSPOT	PCO2	ELDEM	IMP	SHRES	POIL
FROM:	PSPOT		31.66***	28.67***	10.9	12.95	78.04***		47.77***	49.27***	13.79	14.74	45.98***
	PCO2	26.76***		76.29***	3.74	68.30***	109.51***	47.36***		67.92***	2.69	35.6***	433.9***
	ELDEM	31.13***	46.76***		26.79***	32.74***	48.20***	25.51***	59.6***		25.71***	29.12***	124.96***
	IMP	16.14	16.87	8.34		15.28	19.19*	20.41*	14.83	10.23		21.12**	13.57
	SHRES	13.32	41.09***	19.48*	9.11		24.84**	16	56.1***	18.47	7.25		50.8***
	POIL							36.56***	229.5***	57.46***	7.14	38.32***	
	PNG	35.75***	230.37***	100.29***	3.6	77.80***							

Note: *, **, *** indicate significance at 10%, 5% and 1% confidence level.
Source: Commission Services

Table A2.4 presents the results of the short run Granger causality tests for both models. Their findings appear to converge regarding the direction of the causality of most of the variables, except for the change of the electricity imports in the electricity wholesale prices equation and for the change in the electricity imports equation and the renewables equation. In general the tests suggest that for most of the variables there is a bi-directional causality. In particular, in the short run the findings indicate that the electricity wholesale prices are influenced by changes in the carbon prices, the electricity demand and imports, the share of renewables in the total electricity production and the natural gas prices. In the same context, the carbon prices are driven by the wholesale electricity prices, the electricity demand, and the share of the renewables production and the development of fossil fuel prices (Brent, Natural gas). Along the same lines, electricity demand is affected by the electricity wholesale prices and carbon prices, the share of the renewables and the changes in fossil fuel prices that influence the production cost. The share of renewables is influenced mainly by the electricity demand evolution and the carbon and fossil fuel prices. The fossil fuel prices are affected by almost of all explanatory variables through the impact that these variables have on the demand for the fossil fuel commodities. In contrast to the rest of the variables, the tests indicate that the electricity imports are driven only by the electricity demand evolution.

Table A2.5: **Long run causality (Variables in levels)**

	TO:	PSPOT	PCO2	ELDEM	IMP	SHRES	POIL	PNG
FROM:	PSPOT		5.35***	4.33***	0.78	1.56*	7.82***	11.01***
	PCO2	2.74***		5.49***	0.54	3.84***	12.8***	8.55***
	ELDEM	3.69***	6.12***		0.99	4.07***	3.92***	7.70***
	IMP	1.05	0.44	0.45		1.7*	0.3	0.74
	SHRES	1.63*	5.42***	2.93***	0.85		7.23***	3.17***
	POIL	6.06***	31.13***	3.20***	1.31	1.69*		
	PNG	6.02***	41.66***	9.74***	0.94	4.64***		

Note: *, **, *** indicate significance at 10%, 5% and 1% confidence level.
Source: Commission Services

Turning now to the long-run causality among the variables (Table A2.5), the tests suggest that almost for all variables a bi-directional causality exists. Only the electricity imports can be considered as a weakly exogenous variable. The findings indicate that the electricity imports are not influenced in the long run by any of the variables included in the analysis, while they influence only the share of renewables production over the total electricity production.

A2.2. DATA DESCRIPTION

Table A2.6: **Data description – Power price drivers**

Variable	Description	Unit	Source	Sample
Carbon Price	Futures Carbon Prices	€/tCO2	Ecowin	January 2008- July 2014
Electricity Spot Prices	Monthly electricity baseload prices	€/MWh	Platts, Power Exchanges	September 2007- July 2014
RES-E	Monthly gross electricity generated from Hydro, Solar Thermal, Solar Photovoltaic, and Wind	GWh	IEA	September 2007- July 2014
Price of Coal	Coal (ARA) prices in €/tonne	€/tonne	Ecowin	September 2007- July 2014
Total electricity production	Monthly gross electricity generated	GWh	IEA	September 2007- July 2014
Total electricity demand	Monthly electricity demand	GWh	Eurostat	September 2007- July 2014
Imports and Exports of Electricity	Monthly imports and exports of electricity	GWh	Eurostat	September 2007- July 2014
Brent prices	Monthly Brent Prices	€/bbl	Bloomberg	September 2007- July 2014

Note: the data concern the following EU countries: Austria, Belgium, Germany, Denmark, Greece, Spain, Finland, France, Italy, The Netherlands, Portugal, Sweden, United Kingdom
Source: European Commission

ANNEX 3

The transition to low carbon technologies: impact on the merit order curve

To understand the impact on the investment framework of a shift to a technology mix dominated by low carbon energy technologies with high fixed costs and low operating costs, three power systems are constructed that represent each stage of the energy transition.

- Stage 1, the conventional phase, represents power systems that existed 15 to 20 years ago before the deployment of low carbon technologies such as wind and PV

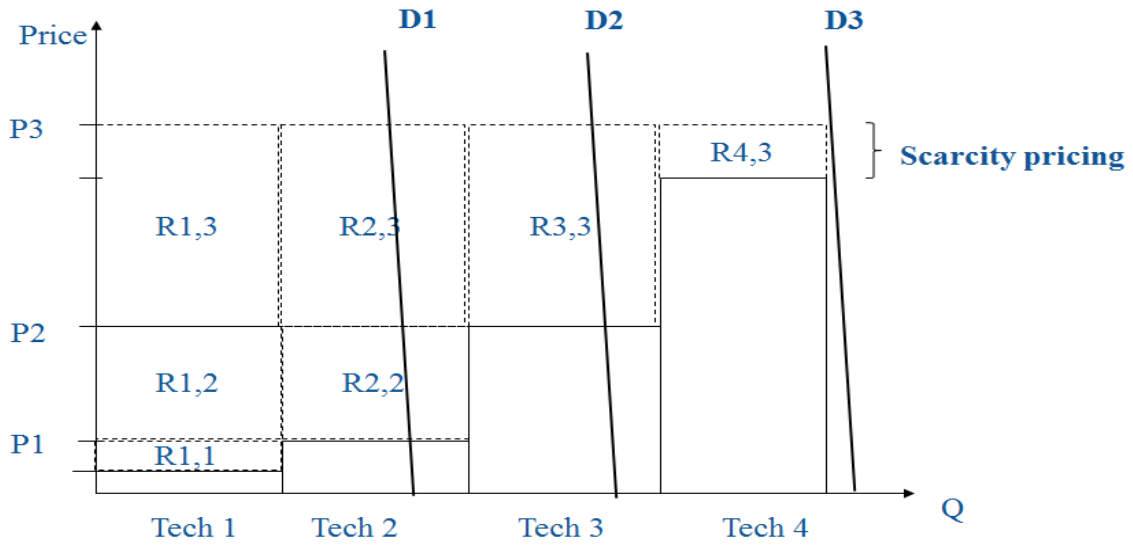
- Stage 2, the transition phase, is representative of current power systems with an increasing penetration of low carbon technologies such as wind and photovoltaic

- Stage 3, the decarbonised phase) represents a future power system dominated by low carbon technologies as can be expected in a medium to long term timeframe.

The demand level to be met is assumed to be the same in each scenario. It is composed of three distinct periods: a base load period where the average power demanded is D1; a semi-base load period with an average demanded power D2 and a peak period with an average demanded power D3. In order to factor in policy developments, the demand is considered increasingly price-responsive, i.e. more elastic, as the energy transition progresses. This is due to a wider deployment of demand response over time in industrial and services sector as well as in households, notably through the use of aggregators. Therefore, the slope of the demand curve changes from stage 1 to stage 3.

Under stage 1, the demand can be met by two technology classes. One technology class is composed of two technologies (tech 1 and tech 2) with low operating costs (OPEX) and high capital costs (CAPEX) such as nuclear or hydro technologies. The other technology class is made of two technologies with high OPEX and low CAPEX such as coal or gas-fired power plants (tech 3 and tech 4). The revenues (R_(i,t) ([85]) gained by each technology in this market framework are sketched in graph A3.1.

Graph A3.1: **Merit-order curves under the conventional phase (stage 1)**



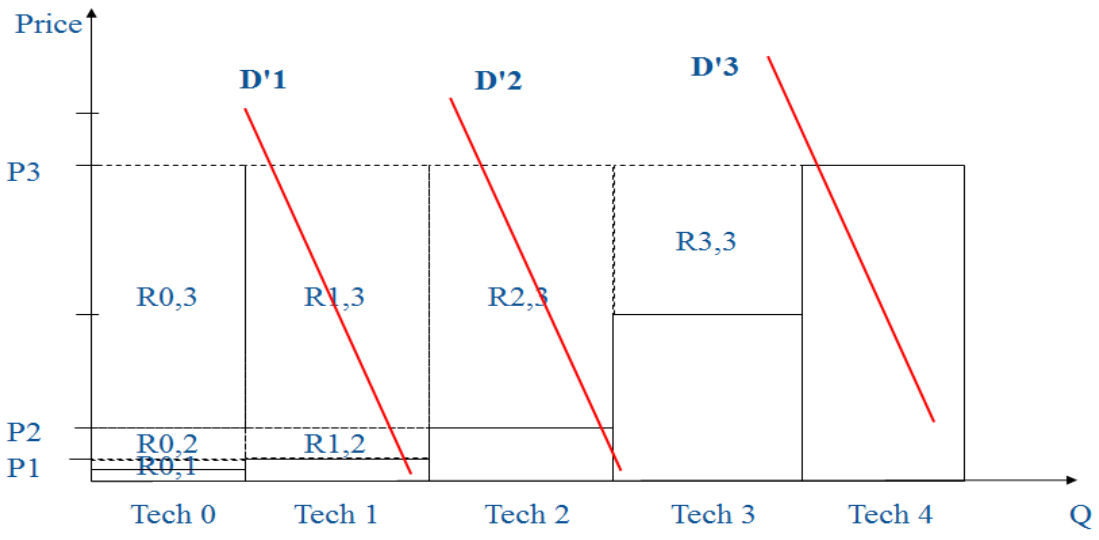
Source: European Commission

([85]) i refers to technology and t to demand period

Revenues for each technology are the difference between the variable cost of the technology and the revenue acquired at the market price when selling the quantity demanded (so-called infra-marginal rents). Accordingly, revenues for technology 1 are the sum of the revenues acquired during demand D1 (R1, 1) when the price is set by technology 2 which is the marginal technology in this case; and the revenues during demand D2 (R1, 2) when technology 3 is the marginal producer; and the revenues during demand D3 (R1, 3) when prices reach P3 that can go up to the value of loss load (VoLL). Indeed, a number of hours of unmet demand are considered to allow for the recovery of the fixed cost of the peaking technology 4, and also to contribute to the cost recovery of the other technologies. The investment criterion for technology 1 is met when these revenue streams equal the fixed cost of technology 1. The same logic applies for all technologies.

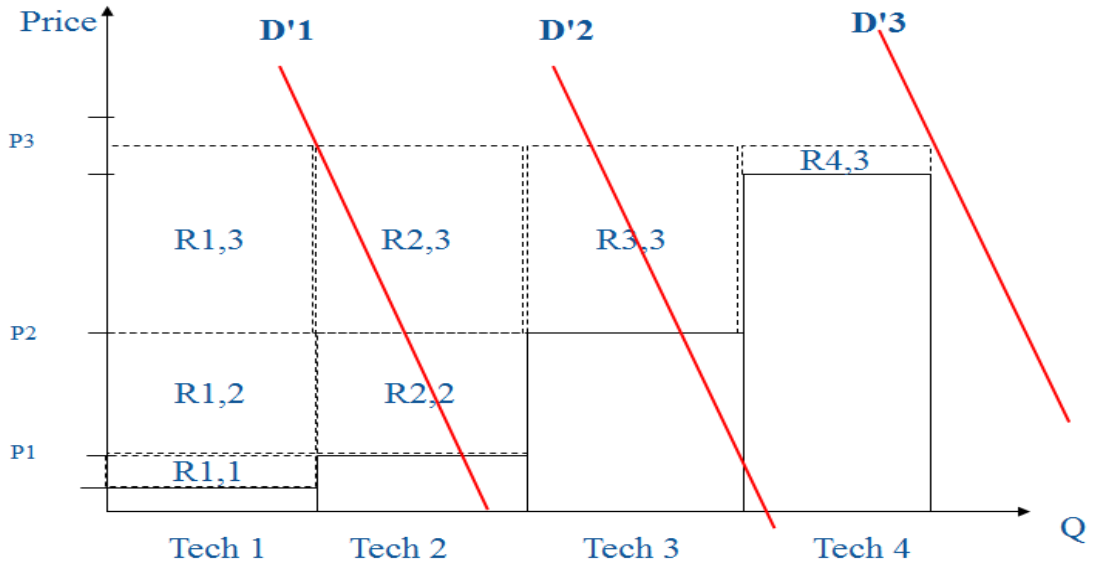
Stage 2 differs from stage 1 as the penetration of low carbon technologies is higher. This is achieved with the introduction of a new technology class, represented by tech 0 that has the lowest variable costs (e.g. wind farms, photovoltaics). The demand levels are assumed to remain constant compared to stage 1, but with an increasing price responsiveness of demand which translates into a flatter curve. This power system could be representative of the current European power systems. The effect on the merit-order curves of the entry of this technology class is portrayed under graph A.3.2. Given that the technologies composing technology class 0 have limited capacity factors due to the intermittency of their primary energy sources, the different demand segments D'1, D'2, D'3 are met alternatively as shown under graph A.3.2 when technologies 0 are operating or as shown under graph A.3.3 when technologies 0 are not operating.

Graph A3.2: **Merit-order curves under the transition phase (stage 2) when technologies 0 are operating**



Source: European Commission

Graph A3.3: **Merit-order curves under the transition phase (stage 2) when technologies 0 are not operating**



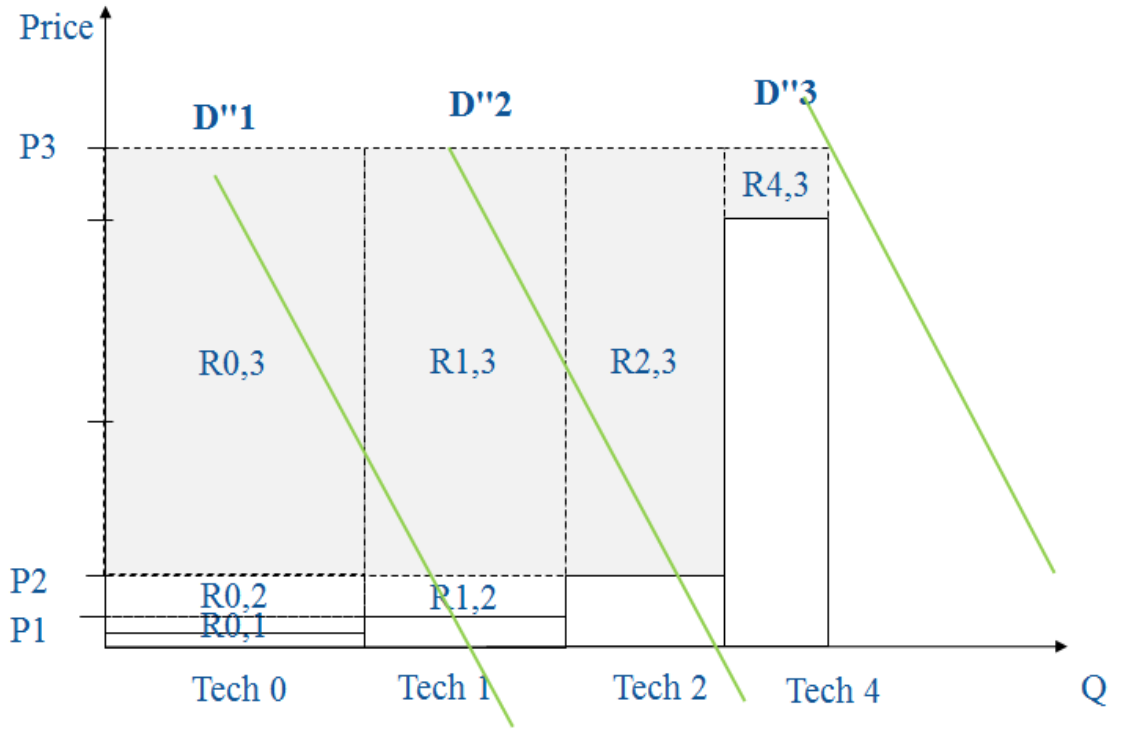
Source: European Commission

The introduction of technology class 0 pushes the merit order curve to the right for a certain period of time proportional to their capacity factors, while the increased responsiveness of the demand decreases the scarcity rent gained by the different technologies. By contrast, when the technology 0 is not operating, the power system is operating with the technology mix as under stage 1. It is noted that under constant demand levels, the financial position of technology 4 deteriorates under stage 2 compared to stage 1 due to an overcapacity effect which limits the number of hours where the price goes above its marginal costs and due to the increasing demand responsiveness which limits the height of price spikes. The resulting impact of the introduction of technology 0 is an overall price, hence revenue, decrease.

Stage 3 represents a power system that would be dominated by low carbon technologies ([86]), with a demand (D"1, D"2, D"3) exhibiting higher levels of price-responsiveness and with a high degree of European market integration. In this context, the system can be managed so that low carbon technologies (class 0) are able to operate during most of the year. This is feasible through drawing on spatial and time complementarities, which can be utilised due to high market integration and regional coordination. The increased penetration of low carbon technologies has resulted in a change in the technology mix, with for instance, no tech 3 and a quantity of technology 4 (as a representative of flexible systems) to meet period of high demand and to account for the resource availability. This results in merit order curves which are flatter and steeper at the end as shown under Graph A.3.4.

([86]) Stage 3 could be expected to start in about 10 years. For example, under the different scenarios[86] of the Energy Roadmap 2050, low carbon technologies start producing around 65% to 70% of the gross electricity generation by 2025-2030. See European Commission (2011).

Graph A3.4: **Merit-order curves under the decarbonised phases (stage 3)**



Source: European Commission

The effect on revenues of this almost complete decarbonisation of power systems is an overall decrease in prices, hence revenues compared to stage 2 for most part of the year. The financial position of all technologies will depend extensively on the frequency and ability of prices to reach high levels. The feasibility of such price spikes is uncertain.

ANNEX 4
Methodology to calculate the annualized capital expenditure

The annualized capital expenditure of technology i CAPEXi is calculated using the methodology described in ([87]), as follows:

$$CAPEX_i = \frac{SCI * (1 + IDC) * CRF}{8760 * Load\ Factor}$$

With:

SCI: the specific overnight capital investment of the power generation facility, in €/MW

IDC: the interest during construction

CRF: the capital recovery factor

Load Factor: the annual load factor of the facility

Values for future SCIs are calculated on the assumption that current prices will decrease due to learning effects. Hence, based on the technology learning theory, the future specific cost of a technology, SCIF, is calculated using the global installed capacity as a proxy, based on the formula:

$$SCI_F = SCI_P \left(\frac{C_F}{C_P}\right)^{\ln(1-LR)/\ln(2)}$$

Where:

SCIP or F: the current and future specific capital investment cost

CP: the current global installed capacity

CF: the installed capacity of the technology in a future time

LR: the learning rate of the technology.

The IDC is calculated considering the construction time for each plant and a capital expenditure profile during construction:

$$IDC = \sum_{k=1}^{CT} W_k (1 + r)^{CT-(k-1)} - 1$$

Where:

CT: is the construction time,

Wk: is the fraction of total capital used in year k,

R: is the interest rate.

For all technologies an interest rate of 10% is assumed for the calculation of IDC. The capital recovery factor (CRF) is calculated from the formula, with d is the real discount rate and n is the economic life time.

([87]) European Commission (2008)