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# What does the European power sector need to decarbonise? The role of the EU ETS & complementary policies post-2020

## Final Report

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Authors

Oliver Sartor (IDDRI)

Mathilde Matthieu (IDDRI)

Pablo del Rio Gonzalez (CSIC)

Verena Graichen (Oeko Institute)

Sean Healy (Oeko Institute)

## About the Authors

**Oliver Sartor**
The Institute for Sustainable Development and International Relations (IDDRI)

**Mathilde Matthieu**
The Institute for Sustainable Development and International Relations (IDDRI)

**Pablo del Rio Gonzalez**
Institute for Public Goods and Policies, Consejo Superior Científicas (CSIC)

**Verena Graichen**
Oeko Institute

**Sean Healy**
Oeko Institute

## About the Project

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## Executive Summary

**A contradiction at the heart of decarbonisation policy in the European power sector**

It appears that there is an emerging contradiction at the heart of decarbonisation policy in the EU power sector: On the one hand, there is increasing recognition of that as the share of renewable and low-carbon electricity generation becomes larger, the existing wholesale electricity market design in many EU countries will struggle to drive the necessary investments in the power sector during the low-carbon transition. On the other hand, a number of EU institutions, including the EU Council and the Commission, have continued to assert the central role of the ETS – an instrument based on the economics of the existing power market design – in electricity sector decarbonisation.

If one interrogates the role of the EU ETS post-2020 with respect to the power market, three fundamental questions must be asked:

- To what extent can the ETS, together with other existing market signals, provide for cost-effective investment in low-carbon technologies?
- To what extent should and can the ETS be expected to drive the decarbonisation and gradual phase out of the existing thermal generation mix?
- What complementary measures should be envisaged and how should they be coordinated with an effective ETS?

To address these two challenges of investment and decarbonizing the residual thermal mix, it is often argued that the EU ETS should be strengthened and other complementary policies gradually phased out. The carbon price, it is argued, could provide a common European price signal that would avoid distortions to the internal market, while ensuring the gradual decarbonisation of the power mix via the declining cap on emissions. This paper argues that this view is too simplistic and likely to be counterproductive to the cost-effective decarbonisation of the power sector.

**The EU ETS and investment in maturing low-carbon generation technologies**

Contrary to the conventional wisdom, a « carbon market only » approach is incapable of driving cost-effective *investment* in low-carbon technologies during the transition – at least based on current technologies. There are four reasons for this:

- The different financial risk exposure of investments in low-carbon technologies to conventional technologies under current power market designs.
- The impact of the low-operating costs of many low-carbon technologies on market price formation.
- The need for coordination between deployment and changes to market design and infrastructure.
- Differing institutional maturity across member states to support low-carbon investment.

Therefore it is important that the carbon market be complemented with appropriate mechanisms to support low-carbon investment and provide visibility for coordination to policy-makers beyond 2020. This is true for both matur(ing) and immature technologies.

When the low-carbon transition began in Europe, a primary goal of investment support policies was to provide *a premium* to immature technologies to close their competitiveness gap with conventional technologies and thus to spur cost-reductions through technological learning. This approach will remain relevant for specific technology niches after 2020. However, for maturing technologies, a key priority must be to *stabilize revenue streams* for investors. Doing so is essential to minimizing the high capital costs of these technologies and thus to minimizing the costs of the low-carbon transition to electricity consumers. Stabilizing revenues streams over longer time horizons is not necessarily inconsistent with the desire to integrate larger shares of low-carbon generation into the electricity market: it is after all, the least cost way to ensure deployment at faster rates than the market "wants".

A broad tool-kit of policy instruments already exists to enable governments to minimize the costs of low-carbon investments. The EU has an important role to play in ensuring that cost-efficient design principles are respected. However, it is important that future rules do not straightjacket Member States into choosing excessively costly instruments for their market circumstances or inappropriate instrument designs, such as blanket rules on tendering or fixed market premia. The end goals of policies to promote EU harmonization and competition – such as cost-reduction and innovation – may sometimes be best served by less harmonization of *policy instruments* themselves, and more harmonization of *instrument design principles*. Put another way, harmonisation of end results matters more than harmonization of instruments.

The use of complementary instruments should not mean that the EU ETS would become irrelevant as a driver of these investments. The EU ETS would remain relevant as an incentivizing instrument for governments to ensure that low-carbon investments are undertaken at a pace consistent with the decline in the ETS cap. To provide market certainty, this should be done during the ex-ante target setting process as the beginning of each policy phase in light of Member State National Energy and Climate Plans.

**The EU ETS and decarbonizing the residual thermal generation mix**

The carbon market should ideally be the main instrument for the decarbonisation of *the residual thermal power mix* and for ensuring *efficient operation of the day-to-day power market*. The carbon market is an effective and efficient tool for driving these changes. Moreover, as a European instrument, it is important that the carbon market play this role to help align power market policy priorities and maximize possibilities for regional coordination across Member States.

However, for this to occur, it is essential that the carbon market provides appropriate scarcity signals in a timeframe relevant to the needs of the power market. The market stability reserve (MSR) is a step in the right direction. Nevertheless, it remains unclear how quickly the market will return to scarcity and, in turn, how quickly it will begin decarbonizing the thermal generation mix. If this process takes longer than expected, an important risk is that Member States with high shares of coal-fired or lignite-based generation may face challenges in decarbonizing their thermal power mix in the time remaining before 2050 (except at prohibitively and politically infeasible high carbon prices).

Addressing this latter challenge will require, at a minimum, transparent and consultative planning and reporting. The new energy plans must therefore set their sights not only on 2030 goals but also integrate a process by which Member States develop decarbonisation strategies to 2050 using a back-casting approach. These are important as a tool for measuring coherence between short term policies and longer term goals relating to minimising costs for consumers, energy security and decarbonisation and also creating effective governance through broad stakeholder representation and peer review.

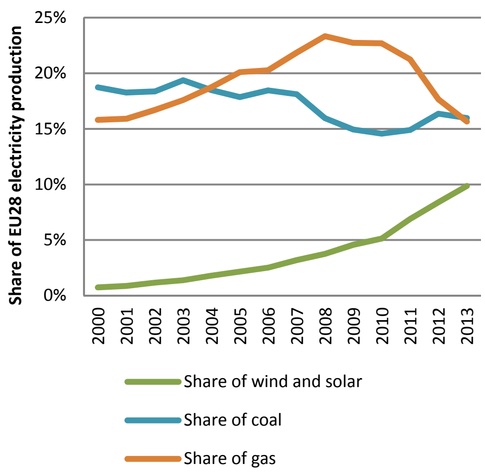
But planning is unlikely to be enough. Avoiding lock-in risks in key Member States with high coal shares will also require a willingness by the EU to confront the political challenges – particularly poorer and coal-intensive Member States – in driving forward a positive decarbonisation agenda for their constituencies. In this context, a potential opportunity created by the Energy Union project is that it brings together different aspects of energy policy that may allow more scope for compromise and reconciliation of differing perspectives among Member States. Further work is required to examine where these opportunities could be best exploited for power market decarbonisation.

## 1. Introduction

In recent years Europe has made progress towards the decarbonisation of its power sector. In particular, the share of generation from renewables has quickly grown from around 14.8% in 2005 to 25.4% in 2013[1], largely due to rapid increases in investment in wind and solar (Figure 1). Large scale deployment has spurred economies of scale and product innovation, which has in turn contributed to rapid declines in costs, bringing maturing technologies, such as onshore wind and solar PV, closer to and in some cases below cost-parity with conventional generation (Fraunhofer, 2013). In terms of changes in the electricity system, the rapid injection of intermittent renewables into the European power grid has been disruptive. However it has also forced decision-makers to address crucial systemic questions about market designs and business models that must be addressed to develop a low-carbon power system.

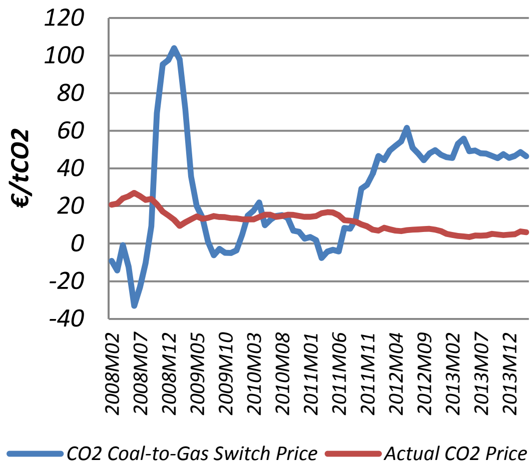
Of course, this progress has not been perfectly even. As Figure 1 and Figure 2 show, some of the abatement driven by renewables has been offset by an increase in coal-fired generation relative to natural gas in the residual generation mix. This has been due to the combination of declining coal prices relative to gas and a weak carbon price. There is therefore a need to strengthen policy incentives for the residual generation mix to ensure that the policy mix for decarbonisation of the power sector is internally consistent.

**Figure 1. Evolution of the share of EU electricity generation of wind and solar, gas and coal**




Source: Authors, based on Odyssee data.

**Figure 2. Comparison of a 'reference' coal-to-gas switching price and the actual CO2 price (Jan 2008-Jan 2014)**




Source : IDDRI, based on ICE data

But while policy framework to date has been relatively effective on the whole at “kick-starting” the EU’s transition towards a low-carbon power sector with renewables, it will also need to evolve in future. In particular, as the share of renewable and low-carbon electricity generation becomes larger, the question of their integration in the market becomes more important. This heightens the importance of questions such as:

[1] Eurostat n.d.

- How to minimize the cost of necessary large-scale investment in low-carbon generation?
- How to ensure sufficient availability of flexible generation capacity?
- How to enlarge the geographic scope and improve the efficiency of the energy and related ancillary markets?
- How to ensure security of supply during the transition?

In this discussion, there is increasing recognition of the fact that the existing model, based on marginal pricing in the energy-only market, while still very important, cannot be sufficient to drive power sector decarbonisation, nor to ensure other basic policy goals are met (Matthes, 2013; Baritaud, 2012; Neuhoff et al, 2015) .

At the same time, a parallel policy debate has been ongoing on how to reform the European carbon market (EU ETS), in which the power sector is the largest single sectoral source of emissions accounting for 57% of verified emissions in 2014[2]. This debate has intensified recently in the form of a specific legislative proposal to create supply response mechanism known as the Market Stability Reserve (MSR). The stated goal of this policy is to return scarcity to the EU ETS in order to make the EU ETS the "main instrument" by which emissions are reduced in the sectors it covers[3]. However, it still remains somewhat unclear exactly what role the ETS is being reformed to perform and whether it is capable of performing certain roles in the sectors it covers.

Indeed, there appears to be a growing contradiction between European policy statements and the reality: on the one hand, in the power market there is increasing recognition of the limitations of the existing marginal pricing model to deliver the necessary investments in low-carbon assets at least cost. On the other hand, the EU Council is re-asserting the central role of the ETS – an instrument based the economics of marginal pricing – for power sector decarbonisation post-2020. Moreover, the European Commission's State Aid Guidelines for energy and environmental aid of 2014 sought to apply strict rules requiring that support schemes be designed as market-based energy price premia[4]. While the 2015 Framework Strategy for the Energy Union also appeared to call for a greater harmonization and gradual phase out of investment supports for matur(ing) low-carbon technologies, apparently with a view that the carbon market would take over[5]. These developments raise an important need to clarify the medium and longer-term strategy that Europe wishes to pursue to drive power market decarbonisation.

This paper therefore seeks to contribute to this debate by interrogating the role of the EU ETS post-2020 for decarbonisation of the power sector, i.e. the largest EU ETS-covered sector. To make this task manageable, this paper focuses narrowly on just three main questions.

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[2]Sandbag (2015) Briefing: 2014 ETS Emissions Analysis, Sandbag, UK.
http://www.sandbag.org.uk/site_media/pdfs/reports/EU_ETS_2014_emissions_data.pdf
[3] Cf. European Council Conclusions, October 2014.
http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/145397.pdf
[4]European Commission (2014) Guidelines on energy and environmental aid, paragraphs 108, 115 and 126
[5]European Commission (2015) A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy, Brussels, 25.2.2015 COM(2015) 80 final, p.15 and p.14.

- To what extent can the ETS, together with other existing market signals, provide for cost-effective investment in low-carbon technologies (particularly in mature or maturing technologies)?
- To what extent should and can the ETS be expected to drive the decarbonisation and gradual phase out of the existing thermal generation mix?
- Given some of the specific limitations of the EU ETS in driving the desired low-carbon transition of the power sector, what complementary measures should be envisaged and how should they be coordinated?

The paper is structured as follows. Section 2 explores arguments for why the EU ETS is unlikely to be a cost-effective instrument for supporting investment in low-carbon generation beyond 2020 – even in the event of structural reform. This section also addresses potential implications for reforms to EU investment support frameworks post-2020, such as the evolution of post-2020 state aid rules. Section 3 explores the potential of the ETS to drive abatement in the residual thermal generation mix. This section also discusses options to ensure that short term actions are coherent with longer-term policy objectives, particularly with respect to lignite plant, which the carbon market may struggle to phase out. Section 4 concludes.

# 2. Investment in (maturing) low-carbon generation technologies

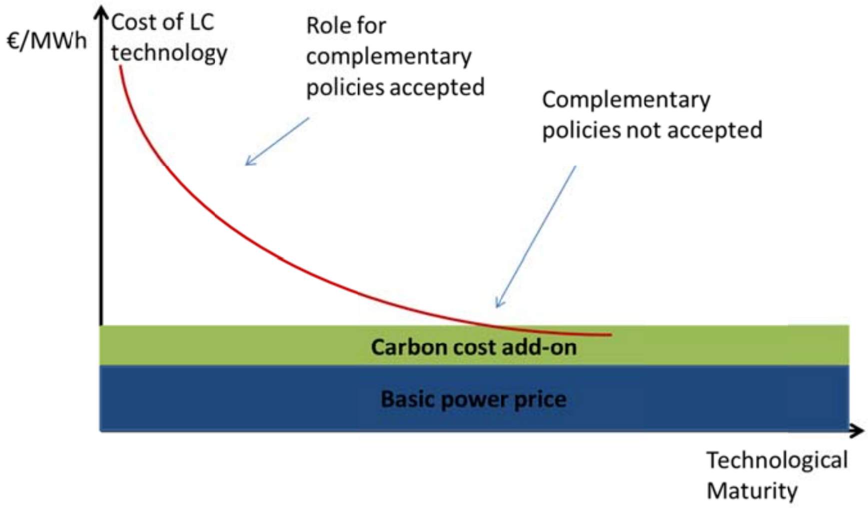
## 2.1. The conventional view

The traditional view of the role of the carbon market in stimulating investment runs as follows: The carbon market cap on emissions ensures that if cumulative emissions start to exceed the carbon market cap the price of CO2 will rise. The CO2 price will continue to rise until it is high enough to incentivize enough abatement to bring emissions back into line with the cap. Moreover, as the price rises, the lowest cost abatement options will be selected first, thus ensuring that the environment goal (respecting the emissions cap) is achieved at least possible cost. Thus, once investment in low-carbon generation technologies come to be among the lowest cost reduction options at the margin, the carbon market will begin to drive investment in these technologies.

Most mainstream economists accept this view, provided that other market externalities are appropriately addressed, a view which goes back to Tinbergen (1952). For instance, it is broadly accepted that there important non-price barriers that can lead to underinvestment in energy efficiency despite the fact that this a least cost abatement option in many circumstances (e.g. Sorrell, 2011). Similarly, the level of the carbon price does not take into account the fact that the more a given technology is produced and deployed, the more its costs will tend to decline; nor does it take into account innovation externalities, such as the potential inability of innovators to fully capture the benefits of developing their technologies. Thus, complementary policies to support early stage deployment (such as the EU's 2020 renewable energy targets) and innovation (such as CCS funding using ETS auction revenues) have been adopted alongside the carbon market in practice.

Beyond this point, however, the conventional wisdom has tended to suggest that complementary policies should go no further. In particular, with regard to investment in renewable or low-carbon technologies, it is argued that once they have reached maturity and the technological learning curve has begun to flatten out, further deployment supports should be phased out and the carbon price should take over the job of rolling out further deployment. This view can be broadly summarized by Figure 3 below.

**Figure 3. The conventional view of low-carbon technology support evolution**




## 2.2. What the conventional view overlooks

The view described above is not wrong per se. It neatly summarizes a significant part of the policy picture and remains a relevant model for thinking about policy. However, it is crucial to emphasize that it is also a significant oversimplification of the reality. In practice, there are a number of crucial details which are critical factors in determining the success and cost of policies to decarbonize the power market. These are now discussed in turn.

### 2.2.1. The high capital/operating cost ratio of low-carbon technologies

A crucially important characteristic of most low-carbon technologies is that they have unusually high capital cost shares relative to conventional thermal generation technologies. Low-carbon generation technologies – whether nuclear power, large-scale onshore or offshore wind or solar, hydro, and even CCS – tend to fit into this category. This matters for the cost of deploying these technologies – even after they have reached technological maturity.

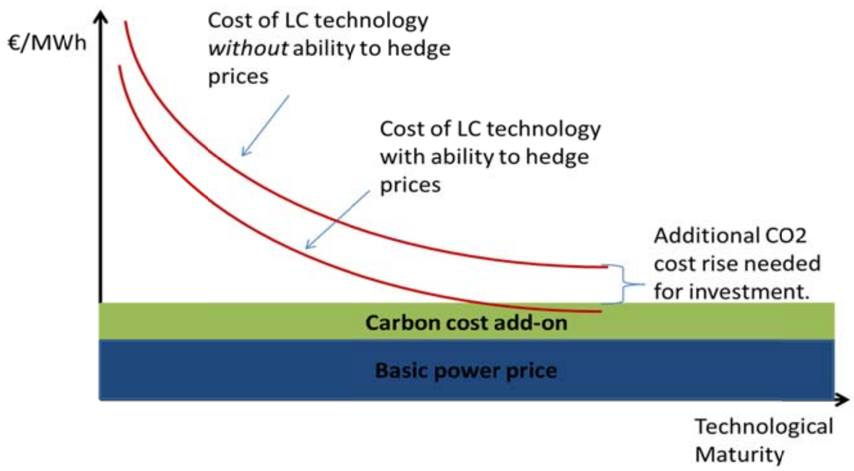
In general, the higher the total capital cost of an investment, the larger is the upfront value put at risk and the longer is the payback period of the investment. Moreover, since they are more capital intensive, these investments tend to be more highly leveraged (i.e. have a higher debt/equity ratio). This in turn means that even a small change in future revenues (prices) can wipe out a significant share of the equity value of the investment and also endanger repayments on debt. Thus the greater will tend to be the demands of the project financiers for assurances against medium and longer term price risk.

Conventional thermal generation technologies, such gas and coal, do not face this problem to anywhere near the same extent. Whereas for wind and solar, capital costs typically comprise close to 80% of the cost of energy, for conventional mid-merit thermal plants, capital costs are often closer to 30% of the total lifetime costs of energy provided by the plant (Neuhoff et al, 2015). Moreover, thermal generation units can often benefit from a « natural hedge » against power price fluctuations. In liberalized markets, price formation is based on the marginal generator's operating costs. Thus, changes in operating costs for the marginal generator can typically be passed through into market prices, thus creating a natural hedge for revenues against cost fluctuations. Since renewables and nuclear have no operating costs, they are infra-marginal rather than marginal generators (most of the time) and are thus not involved in price formation. Thus, their revenues change substantially in response to fossil fuel price changes, adding to the riskiness of these investments.

A consequence of the different levels of sensitivity to price risk of low-carbon vs. high carbon generation technologies is that low-carbon technologies would like to hedge their long-term revenues. However, in most European power markets hedging prices beyond short time horizons (i.e. between 0-3 years) is not possible for large volumes of power. Thus as power produced from low-carbon generation becomes a larger share of the energy mix, it will be impossible for investors to hedge their sales (based on the current power market design). If the future power market design changes to allow for longer-term contracting, then the need for complementary policies that play this role for mature may be reduced. However, at present this is not the case.

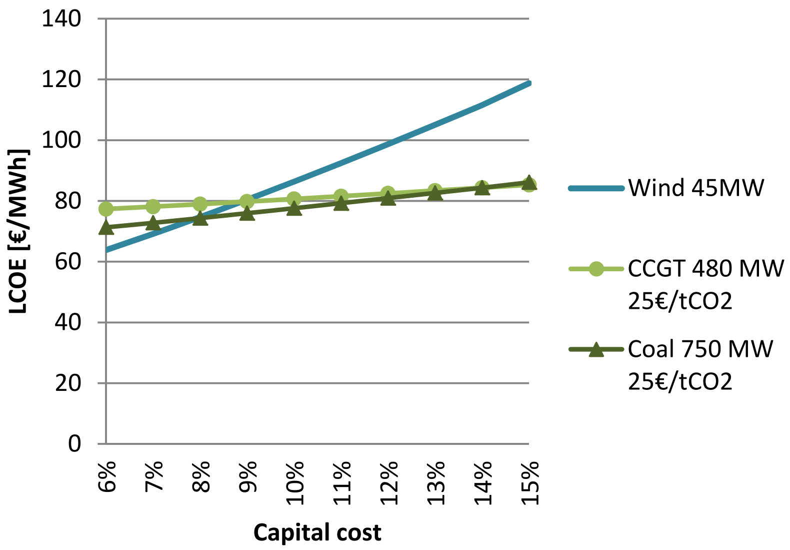
This inability for capital intensive investments to hedge their price risk means that investors are likely to be more cautious about investing. Put another way, they will require a higher expected rate of return to undertake a given investment, to protect against risk linked to price uncertainty. This in turn means that, all else equal, they will tend to require higher power (and thus higher carbon) prices to be willing to invest. Thus, the effective cost of these technologies will rise, raising the overall cost of power that consumers will need to pay to make sure these investments occur.

**Figure 4. The impacts of the inability to hedge price risk on the cost of deploying low-carbon technologies.**



We give an indication of the potential scale of this impact via a simple concrete example in Figure 5 below. The Figure compares the levelized costs of electricity (LCOE)[6] of a new investment in a 45MW onshore wind farm in France with the LCOE a new 480MW CCGT natural gas plant and a new 750MW coal-fired plant assuming different required rates of return. The assumptions underlying the LCOE analysis are included in the annex to this report.

**Figure 5.Levelised cost of wind vs CCGT and hard coal under different capital cost assumptions**




The graph shows two things. Firstly, a small variation in the cost of capital leads to a significant increase in wind farm costs. For example, a 2% change in the discount rates adds 13€/MWh to the LCOE of the 45MW onshore wind turbine; a 4% change adds 26€/MWh, etc. These are significant changes in the cost of electricity. Moreover, note that here we have compared a *small sized* wind farm – the sensitivity of LCOE to capital costs would be larger for larger projects. We have also ignored taxation effects on project return rates.

Secondly, the figure shows that, for two technologies – capital-intensive and non-capital-intensive – that are in competition, a rise in the capital cost will change the relative competitiveness of the two options substantially. This is because the capital-intensive technology is more strongly affected by the rise in capital costs than the less capital intensive technology. Indeed, for a given rise in the weighted average cost of capital, the rise in the LCOE will be proportional to the share of the cost of capital multiplied by that rise in cost. Thus, for a technology like wind that is virtually 80% capital cost, a 10% rise in capital costs (e.g. from 10% to 11%) leads to roughly an 8% rise in the LCOE of the

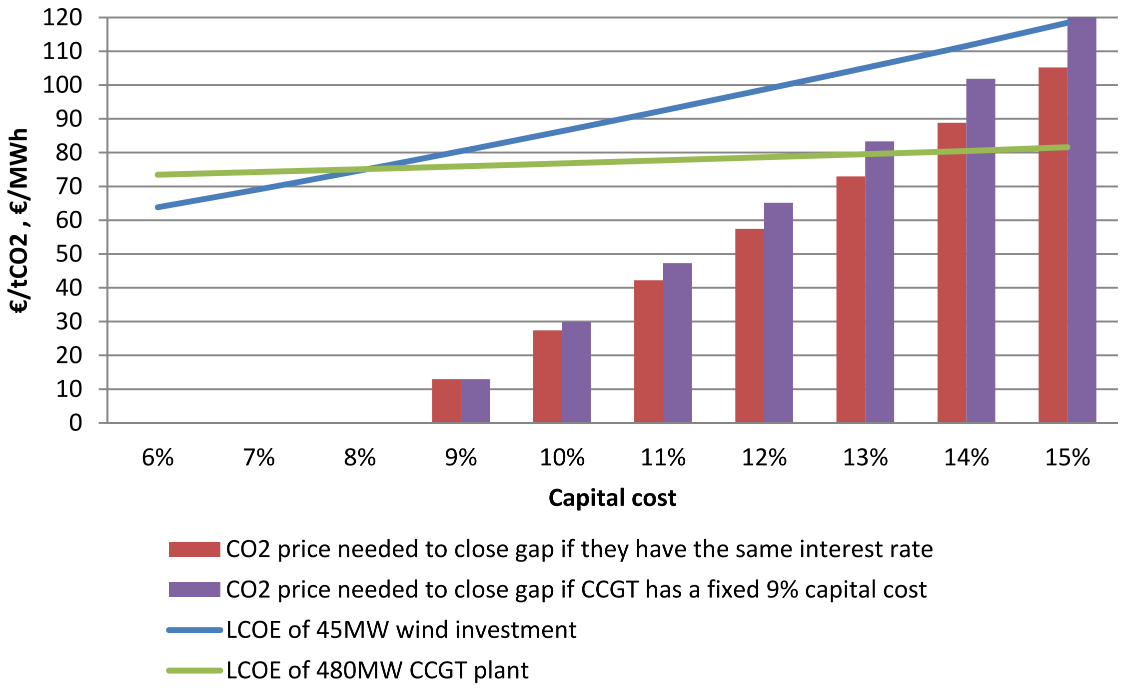
[6] Note that this metric is not a perfect measure of the total competitiveness of a new project, as it does not include expected revenues. However, LCOE is a good metric of the different costs of an investment, which are nevertheless a crucial part of competitiveness.

technology[7]. For the CCGT technology, the low share of capital in the total cost structure means that the rise in LCOE for a given capital cost increase is much lower (in the order of 1%).

The higher sensitivity of low-carbon technologies to capital costs has implications for the use of carbon prices as a way of making these technologies competitive. Specifically, it means that different power prices – and thus different carbon prices – will be necessary to make low carbon investments profitable at different (weighted average) capital cost rates. This can be seen in Figure 6 below. The Figure shows that because even a small wind farm is more capital intensive per unit of LCOE than a CCGT plant, the higher the capital cost that each faces, the greater becomes the cost gap between the LCOE of the wind farm and the CCGT plant. Therefore, to make the wind farm competitive at capital costs greater than 8%, increasingly higher carbon prices would be needed to bring the wind farm back into competition based on the LCOE measure. Thus, at 9% capital cost for the wind farm, only a 12€ carbon price is needed to make the wind farm investment competitive on the LCOE basis. But at 12% capital cost, a carbon price in the order of up to **65€/tCO2** is needed to make the exact same wind farm competitive with the exact same CCGT plant!

Note that these numbers are not purely theoretical: Deloitte (2014) found that representative project *post-tax* internal rates of return for onshore wind investments were typically in the order of 7-9.5%, and 9-11.5%. While Rathmann et al (2011) found that capital costs for renewables projects could vary by between 5 to 30% (of the WACC) across different projects depending on policy design.

**Figure 6. Impact of capital costs on CO2 prices at which a 45MW wind farm becomes competitive with 480MW CCGT**




[7] for offshore wind. Other reports also put WACC costs at between 5.5 and 12.6% in other countries with significant capital availability, such as the US. http://www.renewablesinternational.net/how-germanys-new-renewables-policy-will-affect-wind-power-financing/150/435/80146/

This example shows that the biggest single factor affecting the cost of investing in low carbon generation technologies is the cost of capital. Therefore, if market conditions are not able to minimize those costs – e.g. due to an absence of ability to hedge future price risks via long term contracts – then consumers and other ETS sectors will be forced to pay much higher carbon prices in order for investors to be willing to invest. If this occurs, then it would mean that the ETS would not ensure least cost abatement to meet the EU's climate goals, because carbon prices would be higher than they would otherwise need to be to deploy a given investment in low carbon technologies. Similar results can be shown the case of coal. And for more expensive technologies, like solar PV or offshore wind, the impacts on the required carbon price would tend to be even larger in many cases.

There is increasingly a significant body of evidence in the ex-post analysis literature on renewables deployment policies that suggests that both a) the design of support schemes affects the capital costs of investment in technologies, and b) that the capital costs of investments has tended to be lowest when support schemes were designed in ways that mitigated revenue risk for investors – e.g. using feed-in tariffs. For example, Ragwitz et al (2007), Ragwitz et al (2012), IEA (2011), Rathmann et al (2011) have found that, on average, schemes (such as tradable green certificates) that exposed renewable energy producers to price risk have tended to be significantly more expensive (as measured by the required profit margins of investors per unit of installed generation) than those that have not (such as feed-in tariffs or premia with price controls)[8]. Ironically, these researchers have tended to find that (well-designed) feed-in-tariff schemes tend to consistently outperform TGC schemes in terms of support levels for a given level of deployment, because of the higher risk involved in TGC schemes for investors. This counter-intuitive result is explained by the analysis provided here.

**Conclusion: Based on the current set of low-carbon technologies that are likely to be deployed, the carbon market on its own will not deliver the globally least cost investments in low-carbon generation technologies to the power market. The carbon market on its own is unlikely to be as cost-effective as it would be if coupled with complementary policies that helped to keep capital costs to a minimum, in particular by reducing price risk for investors. This would help to significantly bring down the carbon prices and power prices needed to make these investments happen and thus improve the cost effectiveness of climate policy for consumers.**

### 2.2.2. The impact of low-carbon technologies on market price formation

The view that low-carbon investment support policies should be phased out once they reach market maturity also ignores the importance of the « merit order effect ». The merit order effect refers to the fact that, to achieve decarbonisation of the electricity market at the desired speed, low-carbon generation with very low operating costs are pushed into the market. However, if corresponding amounts of infra-marginal generation are not simultaneously removed from the market, then the

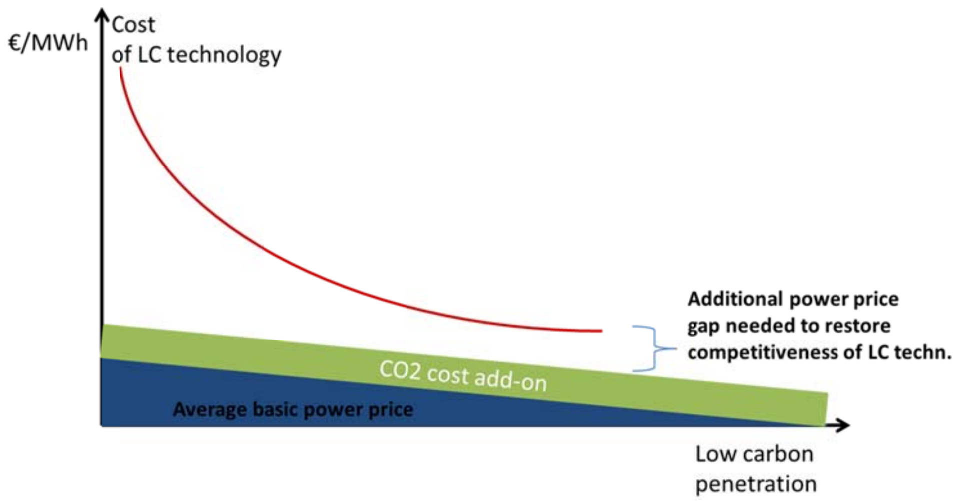
[8]One notable exception to the rule is Sweden, which has found a TGC scheme to be quite cost-effective. However this is in fact a counter example that tends to confirm the rule: Sweden has a large amount of biomass that is fired for electricity generation in very small scale CHP plant with relatively low capital costs. These plant do not require large scale capital intensive investments to the same extent. Thus, the challenges posed in Sweden for RES deployment to date have been fundamentally different to those involving new high capex investments in wind or solar.

marginal generator will change. Specifically, higher cost marginal generation options will tend to be displaced by lower cost, previously infra-marginal generators. This in turn means that the price of power will fall over time as the power mix decarbonizes, because the more expensive generation options are displaced in favour of less expensive options at the margin. This has been shown to occur in several countries, including Austria and Germany (Boeckers et al, 2013) and Spain (Wuerzburg et al, 2013, Saenz de Miera et al 2008)

This has two implications for investors in low-carbon generation. Firstly, **the merit order effect will tend to aggravate the price risk faced by these investors, thus reinforcing the problems related to an inability to hedge risk exposure and its impact on the cost of capital** described in the preceding section.

Secondly, it implies that **additional measures will be required – in addition to the carbon price – if low-carbon technologies are to remain competitive once they mature**. This can be seen from the stylized diagram shown in Figure 7. Thus, this implies that the conventional view, i.e. that supports should be dropped in favour of carbon markets once mature technologies have achieved « grid parity », is based on a false premise. Grid parity is likely to be an ever declining target: the higher the share of low-carbon generation, the lower grid parity prices will be.

**Figure 7. Impact of the merit order effect on the capacity of the power and carbon markets to remunerate low-carbon technologies.**




It is sometimes argued that the merit order effect implies that renewables should not be “pushed into the market” by non-market based mechanisms. However, this argument does not square with the objective of decarbonisation of the power system by 2050. This goal requires that low-carbon technologies be deployed at a faster rate than what would occur if the power system were left to itself to let high carbon technologies expire and then for replacement to occur. Moreover, the question can also be turned another way: shouldn’t existing conventional assets be retired more quickly? After all, the merit order effect also occurs because additional generation assets have been pushed in *without other assets also being withdrawn* to return generation scarcity to the market.

In any event, it is important to take both a short term and long term view of this issue. In the short to medium term, the reductions in price created by the injection of zero marginal cost technologies are likely to continue (unless a large amount of cheap, coal and lignite-fired capacity is retired). **Therefore, at least in the short run, even where the full costs of (variable) renewables are *lower* than the levelised cost of energy from alternative sources, some form of additional policy intervention will be needed to ensure that sufficient investment is attracted to RES-E projects (Piria et al 2013).**

In the long run, it is likely that the current pricing model of many European power markets will also need to change. Under the current market design, as the share of zero marginal cost generation reached high levels of penetration in the power market, prices would be low or near zero for a large portion of the time – with no carbon price at the margin. If this is the case, the current pricing model in many Member States would require intermittent generation technologies to recover their (high) fixed costs during very short and rare periods of very high prices – however, because they are intermittent, such assets would not have control over when they produce. It is therefore not clear how investors in high capex, intermittent, generation would handle the revenue risk involved in such markets. (Moreover, it is unclear what impact the carbon price would have in scenarios in which most of the time it is non-existent at the margin.) The market may therefore need to evolve towards a system with a greater role for longer term contracting and/or prices that are not directly set by the marginal cost of the marginal generation unit at all times[9].

Such considerations suggest another reason why caution should be used in assuming that carbon market can deliver the desired low-carbon investment outcomes on its own. They also suggest that a pricing model for renewables and low carbon generation based on a non-marginal pricing and indeed a form of long term contracting (e.g. feed-in-tariffs or contracts for difference) is not necessarily inconsistent with long run market integration of these technologies – the market design will need to adapt to technologies with (near) zero marginal cost.

### 2.2.3. Coordination needs between market infrastructure, market design and low-carbon technology deployment

The above discussion about market design suggests a third reason why the carbon market is not a sufficient instrument on its own for driving low-carbon investment. There are many aspects to this debate, including the need to increase cross-border coupling of markets and the related market infrastructure; the role of the energy-only market in remunerating fixed investment costs; the manner in which intermittency of renewables is accommodated; the role of distributed generation and its contribution to grid costs; etc. Tackling these challenges within individual Member States, let alone in an internationally interconnected power market such as Europe's, will require active coordination over time.

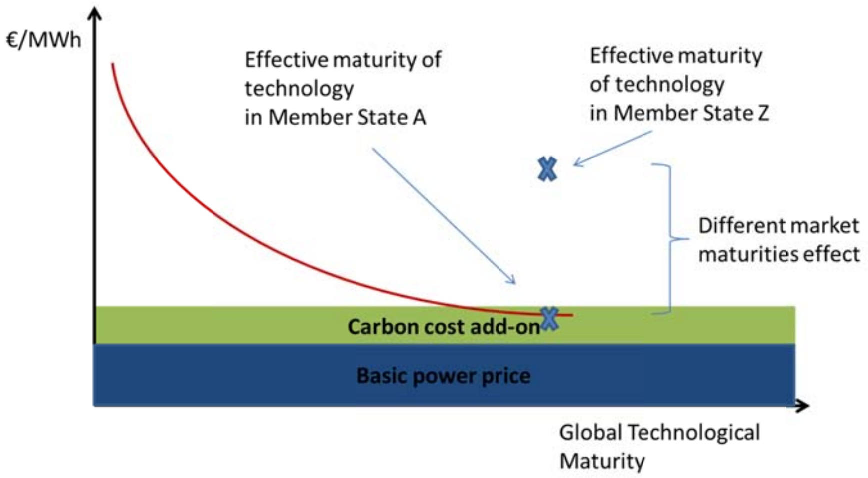
Since this will be done to accommodate increasing shares of renewables and low-carbon generation, there will need to be coordination between changes to market designs and infrastructure

[9] One such model might be the reserve-based pricing model used by FERC to compensate fixed costs of peaking generators in the USA.

deployment and the quantities of low-carbon power generation actually deployed. However, a priori, since the carbon market is effectively blind to these coordination issues, it is prudent to be skeptical. Indeed, this was one of the reasons that the EU ETS was introduced as part of a broader set of policies under the 2020 Climate and Energy Package. **There remains a need for policies that provide greater visibility and predictability about the quantities of low-carbon generation technologies that will be deployed into the market, so that broader systemic considerations can reflect the expected increase in low carbon technologies and plan for them. Among other things, this highlights the importance of clear and credible Member State plans for low carbon energies**.

### 2.2.4. Technological maturity, market maturity and system-relevant innovation

**Figure 8. The impact of different market maturities in a multi-Member State Union**




The conventional view of the role of the carbon market in driving mature technologies also overlooks the fact that technological maturity does not equate to institutional or host market maturity. The cost of deploying a wind farm in an EU Member State with limited experience of doing so will tend to be higher than the costs in a Member State with a very mature market for wind deployment. For instance, one of the reasons for the poor initial policy performance of the UK's original TGC scheme was the lack of experience and a market for RES-E technologies (Ragwitz et al, 2007). In this context, mature technologies may struggle without feed-in-tariffs. **Thus, while from a global technological perspective a given low-carbon technology may be considered « mature »; there may still be significant deployment and learning curve externalities for that technology in a specific market.**

Apart from market « maturity », other local market conditions can also matter for the optimal choice of instruments and their design. For instance, in Sweden large amounts of cheap biomass meant that Tradable Green Certificates (TGCs) proved reasonably cheap because firing of biomass and coal could be achieved in the short run without the need to support financially significant or risky new investments. However, this is not the case in all Member States. **One-size fits all approaches in the**

**name of harmonization and internal market completion should therefore be avoided (Del Rio, 2012, Rathmann et al, 2011).**

In the medium term context for renewable energy, there is also a significant amount of innovation that is taking place around the core technologies. For instance, while onshore wind is generally considered to be at a relatively advanced stage of maturity as a low-carbon technology, significant additional innovation is still occurring[10]. Some of this innovation focuses not only on bringing down the cost of the turbines, but also on how to provide technologies that produce broader system services (such as low wind turbines, that help to balance supply to the grid by ensuring a more consistent flow of power).

However, as innovative technologies, these projects often need to be relatively small scale to begin with and are a higher cost (due to inherent project risk) than the market may bear if placed directly in competition with more mature technologies. Thus, while technologically neutral competition based on a simple categorization of a technology such as onshore wind as "mature" or "not mature" may lead to lower static costs for a specific investment, it may block useful innovation and lead to higher system costs in the long run. The carbon market is not, however, capable of making such distinctions.

## 2.3. Implications for investment support policies and the EU ETS post-2020

The above discussion has shown that beyond 2020, there will need to be dedicated instruments complementing the EU ETS to guide a cost-effective roll-out of low-carbon investments. Specifically, these instruments will need to serve the following purposes:

- Address the failure of current power market designs to allow investors to hedge their higher exposure to future price risk and thus reduce the cost of capital for low-carbon technologies,
- Ensure that the price impact of the necessary injection of low carbon generation does not undermine incentives for new investment ("merit order effect").
- Be consistent with the need for a managed scale up of investment for coordination,
- Avoid a one-size fits all approach

By achieving these goals, complementary instruments to the ETS can help to significantly bring down the total costs of decarbonizing the power sector and ensure the achievement of this goal.

### 2.3.1. Implications for the design of complementary investment policies

The preceding discussion raises the question of which policies should be used to complement the ETS for investment in low-carbon technologies and how to ensure that their costs or spill-over

[10]Discussions with key suppliers of the technology in Europe suggest that they are still heavily investing in research and development (25-30% of staff are employed in R&D activities in some companies wind departments).

effects do not outweigh their benefits. To a large extent the existing policy tool kit of feed-in tariffs, competitive tendering, contracts for difference together with key design options, such as floating (instead of fixed) market premia, growth pathways, and targeted ancillary supports (such as loan guarantees, public financial participation, etc.) is probably sufficient.

In fact, the most important point is often not so much the choice of instrument, so much as allowing Member States the flexibility to adopt the most appropriate instrument and *instrument design* for a specific market, location or technology. Rathmann et al (2011) has estimated that tailoring the right set of policy instruments for a given deployment goal can reduce capital costs for investors by 10-30% depending on the market conditions, the technology, etc. This suggests that blanket rules about the superior efficiency of one more "market-based" instrument over another are counterproductive.

It is important that both national and European guidelines for support recognize this. For instance, the 2014 State Aid Guidelines attempted to provide common rules that uniquely market premia together with direct marketing and competitive tendering should be applied to all support mechanisms from 2016 except in specific cases. This has begun to lead to perverse results in terms of costs. For instance, in France, projects above the exemption thresholds struggle to cope with the administrative costs of centralized tenders, and will face disproportionately higher costs due to grid balancing requirements given the immaturity of the wind forecasting industry. For many smaller scale projects, it is therefore doubted that the benefits of these 'market-based' rules will lead to more cost-effective outcomes for investors and consumers. In Eastern Europe, the lack of financial guarantees and financial sector knowledge can also be an impediment to lower capital costs, etc…

Continuing complementary instruments post-2020 need not imply large additional costs on top of wholesale prices for consumers or taxpayers. Indeed, the low and rapidly declining cost of many low-carbon technologies, such as onshore wind and solar PV, suggest that post-2020 several key technologies will be close to parity, at parity or often below parity with the cost of new investments in conventional coal-fired generation or nuclear (Fraunhofer, 2013). Of course, this may be necessary in some cases, such as to support not yet fully mature technologies like offshore wind, or because of the merit order effects described above. However, a **more fundamental goal of post-2020 must be to *stabilize* revenue streams over longer time horizons than the ETS or current market design can.**

Against this approach it is sometimes argued that a more "market-based" approach is required that exposes all technologies to the same energy price signals. **However, the benefits of so-called "market-based" approaches need to be balanced against their costs.**

For instance, it is sometimes argued that a failure to expose renewable energy sources to spot-market price signals distorts the market because it leads to negative prices during low demand periods and insufficient supply during high demand periods. However, given the intermittence of renewables the scope of operators to increase production during high price periods is limited – outside of scheduling maintenance at low demand periods. Thus, the empirical economic value of such "market exposure" must be demonstrated. We could find only one report assessing empirical evidence of the value of direct marketing in reducing system costs versus the total cost increase for renewables investors due to the higher risk resulting from balancing requirements. This report, by Tisdale et al (2014), found that net costs probably outweighed the net system benefits[11].

Similarly, it is sometimes argued that greater tendering increases competition. However, the evidence on this is more nuanced. The UK's experience with offshore wind to date suggests that, f**or big projects with high information asymmetries between regulators and investors, a well-designed competitive tendering process can help to ensure competition and minimize the costs of deployment and support costs. However, experience in other cases shows that the relatively high transaction costs of tenders will deter the participation of smaller actors and smaller and even medium scale projects, limiting competition and leading to higher bid prices than would be the case with higher competition.** This appears to explain the counter-intuitive results that recent tenders for projects in France and Germany – now required by default under current State Aid rules – have led to feed-in prices that are above the prices offered under the non-competitive feed-in tariffs of those countries (Robert Brueckman, pers. comm. 2015). In such cases, costs may be better minimized and the risks of asymmetric information controlled by other means, such as deployment growth corridors that are used to adjust support levels as necessary under an administratively-set FIT or FIP.

Finally, it is sometimes stated that allowing Member States to tailor instrument choices and design to their needs will encourage a fragmentation of policy and distort the internal energy market. However, this analysis places the issues in the wrong order: the goal of the internal energy market – at least with respect to low carbon investment policies – must be to minimise global energy costs for EU consumers by minimizing the costs of investment for the system. This is done, in part, by choosing the policies that minimise costs of investment in each specific case. To date, those Member States with the lowest costs of support per unit of deployment – such as, in the case of onshore wind, Germany, Ireland, Portugal and Spain (Rathmann et al, 2011) – have tended to follow policy prescriptions that differ substantially from the harmonisation along the lines of specific instruments proposed by the 2014 State Aid Guidelines, for instance.

Indeed, to the extent that there has been convergence of policy at a bottom up level based on Member State experience, the literature suggests that it has been towards policies to mitigate risk via price controls on the premia paid to renewables, towards improving the cost-control mechanisms of feed-in-tariffs via regular degression review or capacity caps, and towards combinations of instruments to achieve greater differentiation of treatment among technology types (Kitzing et al, 2012). A big push towards greater harmonisation along strict rules – such as tendering and market premia or even phase out of supports beyond 2020, as the 2014 State Aid

[11] The existence of negative prices results from both the priority dispatch rules of many support schemes and the lack of flexible generation at the margin. There are therefore two ways of viewing the problem: the first is to see negative prices as a necessary market signal that the generation mix must become more flexible, particularly for marginal thermal generators. Alternatively, if for some Member State specific reasons, negative prices are perceived as a problem, it is possible to introduce measures ancillary to the market as part of the support policy design (such as compensated wind spill rules). Negative prices are not necessary, however, a fundamental problem requiring balancing requirements for small and systemically unimportant actors.

Guidelines suggest – thus represents a significant departure from the conclusions reached by most Member States based on on-the-ground policy-learning (see Annex 6.4).

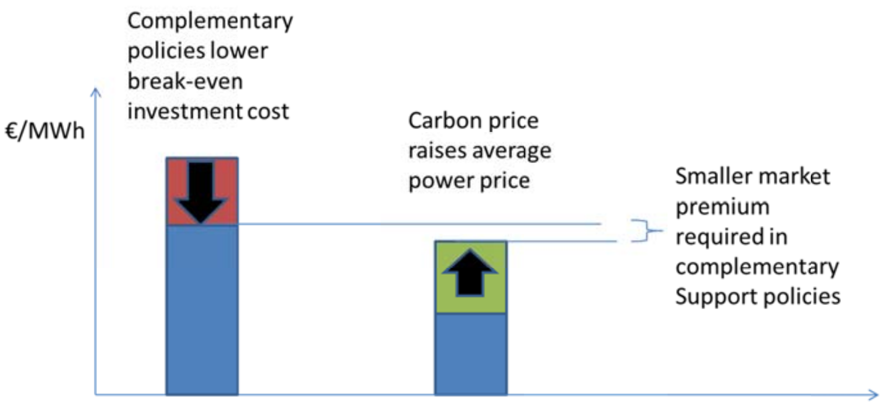
**It is crucial that complementary investment policies to the ETS for deployment of low-carbon generation technologies are continued beyond 2020. It is important that these measures provide for longer-term price signals and revenue certainty than the current power market design can provide, at least until the market design is changed. An approach to low-carbon generation based on contracts for difference, feed-in tariffs, sliding premia and related instruments is not necessarily inconsistent with the future market design of EU power markets. Future EU guidelines should therefore place greater emphasis on Member States respecting certain principles of implementation of support mechanisms (see Annex 6.3 and 6.4), and making full use of the existing toolkit of design features for convergence around cost-effective, but tailored instrument design, rather than focusing one-size-fits-all measures or integration into market based on the currently inappropriate market design for low carbon technologies.**

### 2.3.2. Reconciliation of investment policies with an effective EU ETS

A common criticism of arguments for complementary investment support policies to the ETS is that these policies undermine the carbon market (because they reduce demand for ETS allowances and thus lower the carbon price). Therefore, it is argued, they should not be implemented. Thus renewable supports and carbon market approaches are often placed in opposition.

However, this is a false opposition for several reasons. Firstly, a carbon price that reflects the CO2 externality cost reduces the level of investment support premia that need to be paid to investors in low carbon technologies. At the same time, by lowering the capital costs of investments in low carbon technologies, effective complementary investment policies also lower the carbon prices at which low-carbon investments become competitive. Thus, these investments can be made with lower and in some cases no market premium.

**Figure 9. Complementarity of ETS and investment support policies for driving least-cost investment**

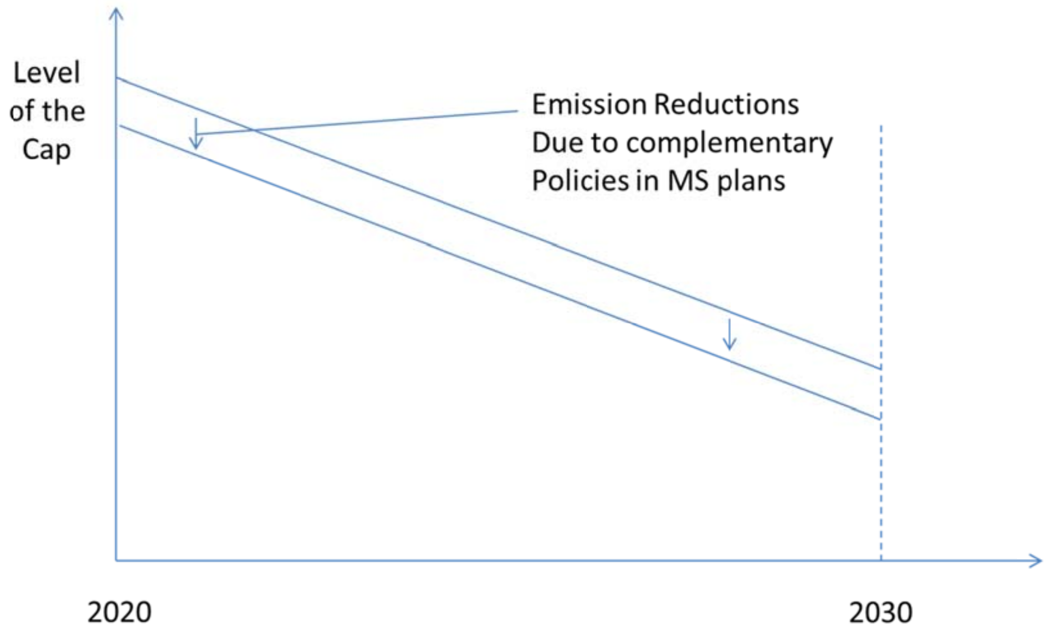



However, while complementary policies make investments in low-carbon generation technologies less costly, they also bring forward abatement that would otherwise not have been driven by the carbon market in a given period. Thus, they will also tend to reduce the overall scarcity of allowances in the carbon market. Thus, they will tend to reduce carbon prices compared to business as usual and slow abatement in other activities covered by the ETS. Moreover, if the surplus size is large – as is presently the case in the EU ETS – an excess of allowances can lead to the carbon price falling below levels consistent with sound market functioning.

Given this risk, a simple solution is to tighten the EU ETS cap *ex ante*. This makes economic sense: because the EU ETS cannot cost-effectively drive certain forms of abatement, other policies are used. If these policies work, then the residual abatement work for the ETS left to perform is smaller. Thus, the ETS cap should be reduced by an equivalent amount beforehand to reflect the expected impact of complementary investment support policies.

Coordination between the level of the EU ETS cap and low-carbon investment which is enacted in response to Member State policies that operate independently of the carbon market should ideally be done at d*uring the ex-ante target setting process as the beginning of each policy phase (i.e. the review of the linear reduction factor that determines the ETS cap).* Doing so ex-ante is important for two reasons. Firstly, it is important for the market to have clarity on the level of scarcity that will exist in the market after overlapping policies are taken into account. Secondly, the use of ex-ante adjustment would ensure that EU ETS acts an incentivizing instrument for governments to ensure that low-carbon investments are undertaken.

**Figure 10. Schematic diagram of cap adjustment process**




**We therefore propose that an explicit adjustment be made to the level of the ETS cap to account for the level of abatement that can be expected from investments in low-carbon generation intended by Member States in their National Energy and Climate Plans under the new 2030 climate governance framework**. The level of the ETS cap is of course a political question to a significant extent. Nevertheless, a science-based option for recalibrating the cap might be to remove the share of abatement that is expected to be generated from the achievement of Member States renewables targets from the Commission's modelling scenario that determines the cost-efficient abatement pathway for the ETS sectors before each phase. At present, the Impact Assessment modelling accompanying the target-setting process has assumed that renewable and low-carbon generation investments can be driven by the EU ETS cost effectively. However, this assumption is unrealistic, as argued above. It thus should not be included in the underlying modelling scenario that informs the choice of the optimal linear reduction factor for the following phase. **Rather the absolute level of the cap should be set based on the optimal abatement pathway for the activities for which the ETS is the main instrument for driving abatement. In general, this should lead to a slightly tighter cap than would otherwise be the case, as it will need to be adjusted to account for the extra "space" that is created by complementary policies for low carbon generation (see Figure 10).** To provide certainty for both ETS-complying actors and renewables investors, this could be done 5 years prior to the following ETS phase, e.g. during the 5-year review point during each ETS phase. The proposed Australian system of rolling ETS caps could be an instructive example in the design of this process.

## 3. Decarbonising the thermal generation mix

Provided that there is sufficient scarcity of allowances in the market, the EU ETS is a potential very effective and efficient instrument for driving the higher carbon alternatives out of the residual power mix. This has been demonstrated in previous literature on the impact of the EU ETS on power sector emissions. For example, Ellerman and McGuiness, 2008; Berghmans and Sartor, 2011 and Solier, 2013 among others, have all provided econometric evidence which show a direct causal link between the periods of robust carbon prices during Phases 1 and 2 of the ETS and switching from coal to gas in the power sector. Looking forward, the potential for the ETS to drive similar fuel switching is also evident. This section looks empirically at the potential of the EU ETS to drive this decarbonisation and at the specific challenges that decarbonisation of the residual thermal power mix entails.

Section 4.1 looks at the empirics of decarbonisation of the residual thermal generation mix in the EU. Section 4.2 compares these empirics with the political outcome of the market stability reserve negotiations on ETS reform. Section 4.3 then examines areas where complementary policies may have a high value added.

### 3.1. Fuel switching in the thermal power mix & the role of the ETS

#### 3.1.1. Fuel switching in analysis (static analysis)

There are two basic ways in which the thermal power can be decarbonized: a) due to displacement of thermal generation by low carbon alternatives and b) due to "fuel-switching" between high and less-carbon intensive technologies (such as lignite to coal or coal to gas). Fuel switching potential can in turn be evaluated both in terms of present switching capacities and in terms of the potential for new lower-carbon plant to displace existing or new high-carbon plant. We now address each of these potentials in turn.

As a first step to assess the current potential of the ETS to drive fuel-switching, we estimated the marginal fuel switching cost curve for a sample of seven Member States with large power markets and significant amounts of coal-fired generation in their power mix: UK, Germany, Poland, Italy, Spain, Czech Republic and Romania. The use of a partial representation of the EU power mix means that the analysis below provides only a partial picture of the fuel switching potential. Nevertheless, these countries together account for approximately 66% of total EU power emissions that are covered by the ETS. Thus, the results are still instructive and allow for several qualitative conclusions to be drawn.

Seven scenarios were constructed depending on the respective costs of the fuel inputs, summarized in Table 1 below[12]. The cost of fuel inputs are also adjusted in the case of the UK to allow for the carbon price charge of 18.08£ that is expected to remain constant for the foreseeable future. The curves are constructed based on plant-level data from Enerdata's power plant tracker database and Oeko Institute (for Germany).

The switching potentials are calculated based on an assumption of average power demand in 2013 (with an adjustment made to remove peak load periods when switching potential may not available). Specifically, the generation resulting from 200 hours of annual demand corresponding to peak times was excluded from the analysis. Apart from this, the model does not take into account network constraints and must-run scenarios for specific plant. Long-term contracts are not taken into account, thus the scenarios here can be thought of as representative of situations over extended periods where contract prices can be renegotiated. Ignoring these factors may tend to slightly overstate the fuel-switching potential in the short run. Thus, these figures should be interpreted as static estimates.

**Table 1. Fuel price assumptions for scenario construction**

| **Gas price \ Coal price** | *High (90€/t)* | *Medium (67 €/t)* | *Low (35.3 €/t)* |
|---|---|---|---|
| *High (33.6 €/MWh)* | | | X |
| *Medium (24.5€/MWh)* | X | X | X |
| *Low (14.9 €/MWh)* | X | X | |

Source: Authors based on historical data from IMF commodity price database

**Figure 11** shows that in 6 of the 7 scenarios there is substantial potential to switch from coal to gas and thus to reduce emissions based on *existing* installed capacity during average demand periods. For instance in the central scenario, based on recent prices, a significant switch from coal to gas begins to takes place above a carbon price of around 20 €/tCO2 and by 40€/tCO2 around 150MtCO2 of emissions can be displaced from the merit order annually. This corresponds to 27% of current power sector emissions in these 7 countries combined. At higher prices, up to 225MtCO2 (41% of emissions) could be abated. Once again, this is just based on existing fuel switching capacity during average demand periods and excludes abatement from new investments.

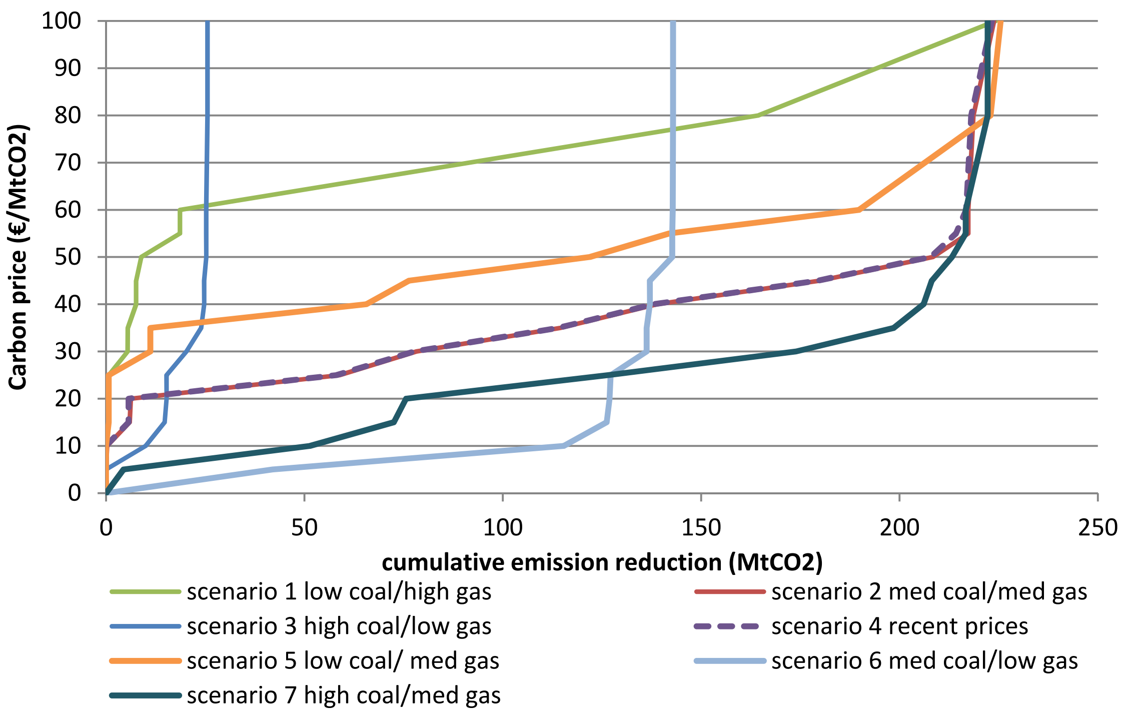
[12]The prices for these scenarios were chosen to reflect the 25th (Low), 50th (Medium) and 75th (High) percentile of the distribution of monthly average prices (in 2014 USD) of EU Gas and Australian Coal prices reported by the IMF Commodity Price Database from January 2000 to June 2014. These prices were then converted to Euros using the February 2015 USD/EUR exchange rate. In addition, a « recent prices » scenario using average prices from the last 6 months of 2014 was constructed. Lignite prices come from Booz&Co. and differ among countries. In practice it is likely that more switching from lignite is possible due to price variation around our assumption

The CO2 prices at which fuel switching occurs vary significantly across the different fossil fuel price assumptions – as would be expected. Although even in the extreme fossil fuel price cases, the entire gas to coal switching potential is exploited below 100€/tCO2.

The CO2 price to trigger fuel switch varies significantly along the distribution of CO2 emissions abatement quantities, reflecting different power plant efficiencies and lignite prices. However, it also reflects differences in domestic policies. The UK carbon price floor, for instance, leads to a large potential to abate emissions in the UK from an ETS CO2 price of around 20€/tCO2 due to an existing base of around 25€/tCO2 in the domestic coal price for coal-fired plant.  It is noteworthy that even in the low-coal price, medium or high gas price scenarios, substantial fuel switching potential exists. Only in the low coal price, high gas price scenario is switching potential very limited. This reflects the fact that almost available capacity for switching has already been used and thus additional investments would be required to allow for more switching.

Fuel switching is sometimes seen as a poor relation to other abatement alternatives because fuels can be “switched back again”. However, the analysis described below is important in so far as it implies that at the CO2 prices indicated, the coal plants included in the model are no longer producing during periods of average or below average demand. Thus their operating hours are declining – the environmental goal – and they are therefore on track to being shut down definitely.

**Figure 11. Potential abatement from fuel switching in 7 key Member States**




The extent to which the fuel mix changes in the power sector of the seven countries is also demonstrated in Figure 12. It is based on the recent prices scenario. It shows that at 50 €/tCO2, virtually all of the available gas capacity has been used in these Member States and the share of gas climbs to around 50% of the residual fuel mix. Meanwhile, coal and lignite fall from around 95% of the residual mix to around 50%.

**Figure 12. Share of different fuels in the combined thermal power mix of all seven Member States at different CO2 prices**

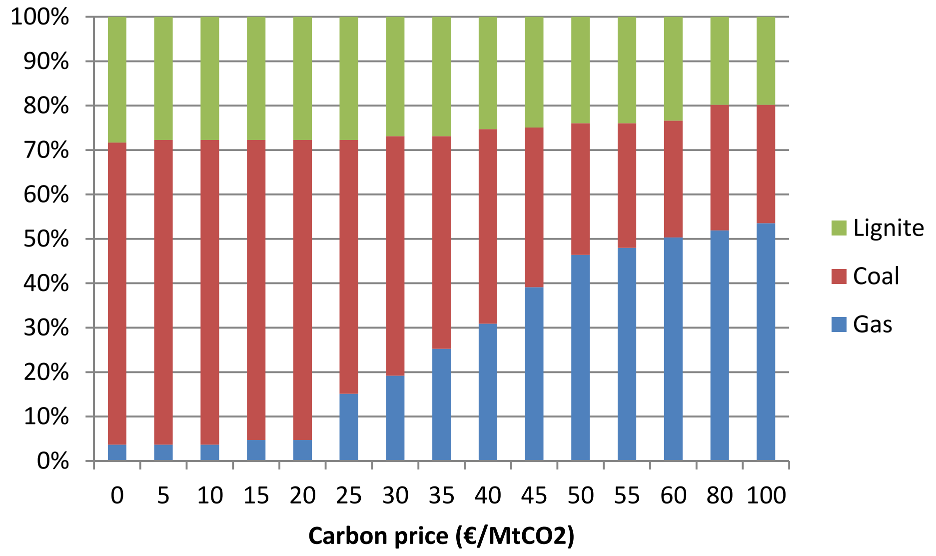
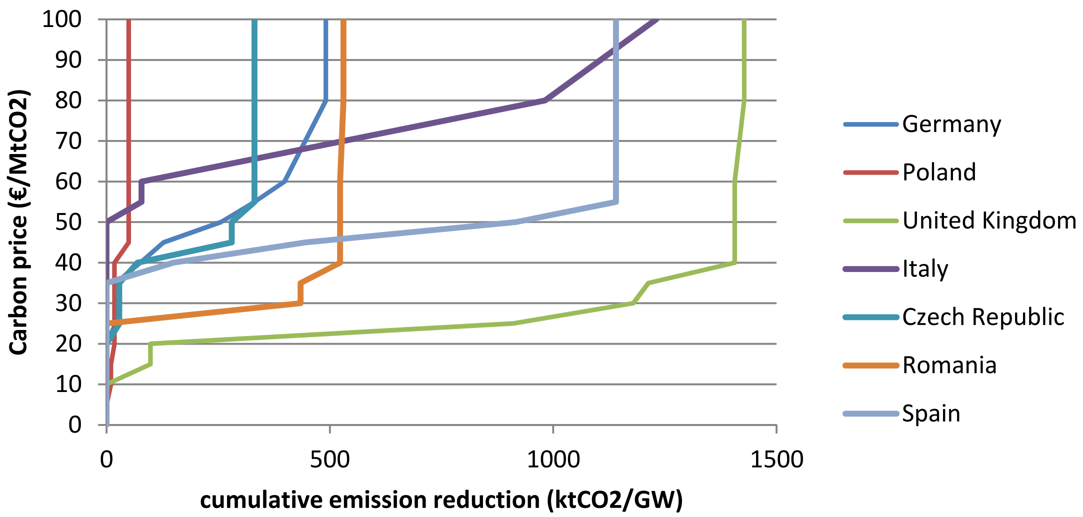



**Figure 13. Switching potentials by country in the sample (expressed as ktCO2/GW)**




The inability to shift this remaining 50% of coal reflects the fact that some Member States lack sufficient switching capacity. In some European power markets, such as Poland, very low existing natural gas capacity means that switching potentials are extremely limited. In others, switching potential also hit an upper bound once existing gas capacity is fully utilized (see

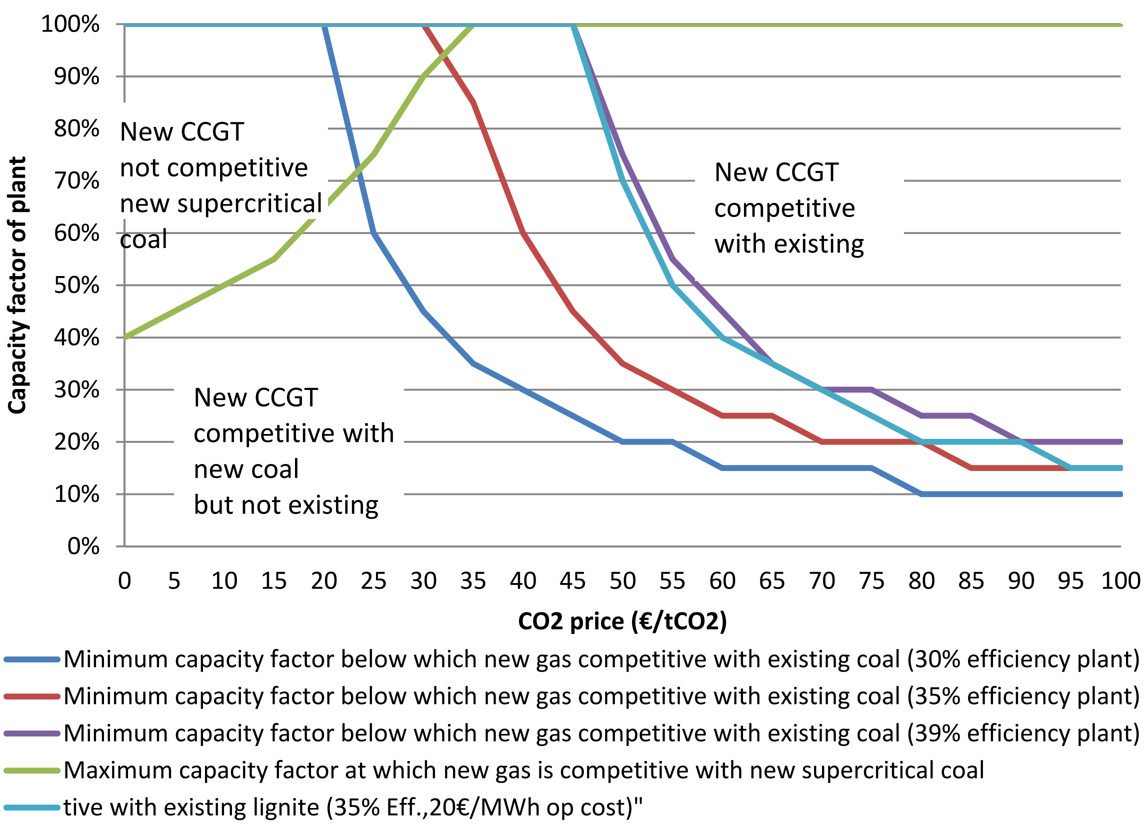
Figure 13). This also seems to be the main factor below the low share of lignite that is phased out, since in our underlying assumptions, lignite prices are usually in the order of 50-80% of current hard coal prices but higher CO2 costs and lower plant efficiencies make them more expensive to run than CCGT in many cases (see assumptions in Annex 6.5).

Figure 13 also helps explain why some Member States such as Poland and the Czech Republic show such low political support for the ETS as it shows that they have virtually no domestic stakeholders in the power market who directly benefit from the carbon price.

### 3.1.2. The role of CO2 prices for investment in CCGT vs coal (dynamic analysis)

The above analysis focused only on the potential for fuel switch based on *existing installed capacity*. In practice, however, companies also face the choice of investing to replace coal-fired power plant. In countries such as Poland, Czech Republic, Germany, and Romania, additional CCGT might also need to be built to phase out coal and lignite while complementing supply from low-carbon sources.

**Figure 14. Investment competition between coal and natural gas**




Note: These estimates do not take into account additional regulatory costs, such as the impact of the LCPD (discussed above), possible additional revenues from ancillary market services to the power market, or local conditions.

**Erreur ! Source du renvoi introuvable.** provides a rough back-of-the-envelope analysis of the incentives for doing so. Specifically it compares the competitiveness of new CCGT plant with a 58% efficiency rating with both new and existing coal-fired plant. New coal is assumed to be supercritical with an efficiency of 45%. Existing coal/lignite is assumed to have varying levels of thermal efficiency. The carbon prices and capacity factors at which new gas would be competitive are then compared to show the regions in which one might be able to expect new investment in gas. The gas and hard coal price assumptions are the same as in the "recent prices" scenario described in the static fuel-switching analysis above.

Note that these estimates do not take into account additional regulatory costs, such as the impact of the LCPD (discussed in Annex 6.6), possible additional revenues from ancillary market services to the power market (such as balancing services for gas plant), losses from lack of flexibility (e.g. due to technologies like coal and lignite with longer ramping times) and local environment conditions (such as political opposition to building new coal plant). Another caveat is that our analysis splits coal plant into two categories: brand new and existing. In practice, however, many coal plant in the EU are old and will require significant reinvestment at some point in the next decade or so. To try to reflect these costs, it is assumed to have low-to-moderate annual fixed cost in this analysis (around 50 000€/MW per year). However, this does not fully reflect the lumpy way in which these costs are spread and this tends to overstate the competitiveness of coal at high carbon prices.

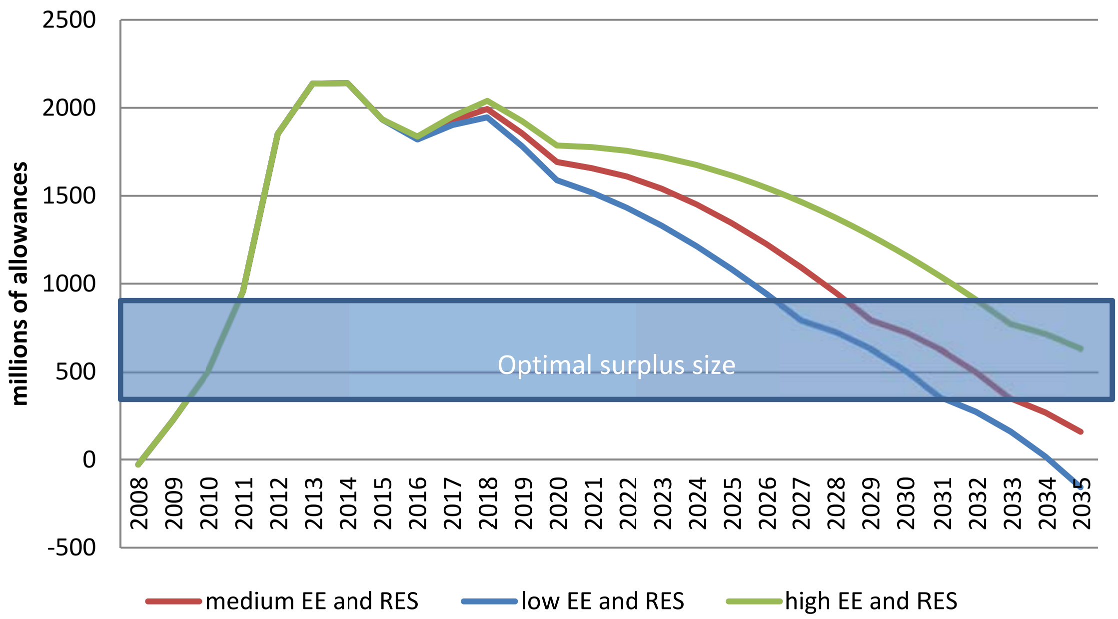
**These results of the analysis suggest that the ETS is also capable of driving the required shifts not only in day-to-day operations but also in investment between thermal generation assets**. For example, from 25€/tCO2, new CCGT begins to become competitive – all else equal – with existing coal for mid-merit power production and for base load power from around 35€. (For peak load plant, existing coal remains competitive at high carbon prices. However, the imperfections of the modelling exercise needs to be borne in mind: existing coal is assumed to have low annual fixed cost in this analysis (around 50000€/MW). However, in practice this will be true only until significant reinvestment decisions become necessary. At this point, the plant will fall into the new investment category and lower carbon prices would see them close.  The lignite cost is assumed to be 20€/MWh here.

## 3.2. What can be expected from the agreed MSR reform?

Recently, a political deal was reached on the basic parameters of the market stability reserve reform in the EU ETS. These included a 2019 start date, a 12% rate of entry of allowances into the reserve, an automatic return of the backloaded and unallocated phase 3 allowances into the reserve. In Figure 15 we model the expected impact of these parameters on the surplus in the EU ETS and compare it to the « optimal surplus size » that is roughly thought to be consistent with new incentives for abatement, including fuel switching.

This modelling is based on three emissions baseline scenario projections post-2020, one in which emissions from heat and power decline by 2% p.a., one in which they decline by 2.7% p.a. and one in which they decline by 3.5% pa. These scenarios reflect different possible scenarios that one might assume in terms of the rate of increase of energy efficiency and renewables within the scope of the ETS. The wide differences between the scenarios help to highlight the argument made above that there is strong need for coordination between the cap setting process for the EU ETS and the design of overlapping policies.

Figure 15. Evolution of EU ETS surplus size under different MSR designs




Note: this analysis assumes no abatement in response to the decline in the surplus size and the subsequent effect on CO2 prices. It is therefore a business as usual analysis only. Therefore, it should not be used, for instance, to interpret the surplus size expected after the optimal surplus size is reached.

We believe that once the surplus size reduces to around the level of the optimal surplus size (or slightly above it) then new incentives for abatement in the power sector would be created, as the market would begin to be short of allowances as a whole. Moreover, it is likely that, to some extent, in the years just prior to that point, the market will anticipate future scarcity and thus carbon prices will start to rise to levels consistent with fuel switching in the years prior to the market actually becoming short. If this assumption is correct, then our analysis would suggest that the reform agreed by the EU Council and Parliament could lead to renewed fuel switching by around the middle to the end of Phase 4 (2025-2030), depending on the scenario.

This highlights the possibility that with the politically agreed reform of the ETS, the surplus could still take quite a while to generate large scale action towards decarbonizing the residual thermal energy mix.

## 3.3. Is there a role for complementary policies for decarbonising the residual thermal power mix?

The preceding discussion has suggested that the ETS can be an effective instrument for internalizing the cost of the CO2 externality into the investment and operational decisions of conventional thermal assets and driving carbon-intensive options out of the market.

We would also suggest that **it is also important that the ETS play this role of driving decarbonisation of the thermal power mix because it is *a European instrument*. Through a common carbon price, it can thus help to ensure coherence between the actions taken to decarbonise the thermal power mix in different Member States. This coherence is important if one considers the regional and European coordination needs of the power system for decarbonisation. This is a crucial aspect of the ETS that is often overlooked.**

However, it has been also noted that this fuel switching might in practice take time to eventuate. This raises the question: is it a problem if the ETS did not drive much fuel switching and decarbonisation of the thermal power mix prior to late in Phase 4 of the ETS?

The principle of the ETS is that the cap binds the emissions of the emitters and that as the long run scarcity of allowances begins to bind, the price should rise until the rate of turnover of capital stock increases. One must also be cautious in proposing additional policies where they will tend to add complexity and or come with risks that they significantly distort incentives. For instance, a planned phase out of old plant might be desirable, however if the political economy of phasing out these plant means that they must be paid to leave the market, then this could also contribute to problems of overcapacity (because plant that would close anyway will not close in expectation of the payment).

On the other hand, one must be careful not to be too naïve about the ability of the ETS to drive large scale replacement of capital stock in short time periods. For instance, it was shown above that a country such as Poland currently has very low switching capacity to gas. In Poland, roughly 90% of power is still generated with coal and lignite and its current 2030 energy plan would leave around 35GW of coal capacity in its system, producing 75% of its power in 2030. Much of this will also be supported by the issuance of free allowances to the Polish generation fleet under Article 10c of the ETS Directive – an article which looks likely to be continued beyond 2020. It is questionable whether Poland would be able to replace these 35+ GW of power in a period of 20 years. Thus, it seems clear that unless carbon prices begin rising much sooner than currently expected under the MSR reform, then some countries may place themselves into a corner in which phase out of the thermal generation mix is difficult in the time required.

This example highlights the importance of governance instruments that help to ensure coherence between short term policies and long term goals. There is a temptation here to propose additional instruments (such as Emissions Performance Standards, etc). While strengthening existing policies around local pollutants can be an effective complement to the carbon price at phasing out old plant when reinvestment decisions come, it must also be squarely confronted that the barriers to a stronger MSR reform and earlier phase out of coal plant are not technical, but political.

In this context, we therefore propose two new elements here. Firstly, **there is the importance that the planning element of the new climate and energy governance mechanism include details about how Member States intend to manage the constraints placed on their energy sectors by the ETS cap both to 2030 *and* to 2050.**

The role of the plans to *2030* with respect to the ETS sectors would be to detail the Member State's strategy for responding (or helping consumers and business to respond effectively) to constraints and changes in relative costs imposed by the ETS. This is important as, done well, it would help to oblige Member States to be coherent in the policies, to follow through on their commitments to their regional peers.

To make these plans credible, they must be developed via engagement with domestic stakeholders, the Commission, and with regional neighbours (e.g. neighbouring Member States with power interconnections). Good governance principles that require such consultation and give guidance on how it should be done should therefore be enshrined in EU documents outlining the implementation of these plans. Ideally, EU Member States should also be required to legislate the achievement of key parts of their own plans domestically.

The plans would at a minimum require forecasts of key indicators that provide an overview of the power sector and its decarbonisation, including total demand, total system supply, CO2 intensity of electricity, and production shares of different fuel types.  In addition, strategies to mitigate costs for consumers should be explained. This would oblige Member States to consider the risks of lock-in of high carbon assets for their consumers.

As *a second step*, Member States would also be required to explain how their actions to 2030 are consistent with meeting the EU's *2050* decarbonisation targets, with minimizing longer term energy costs of consumers (again reflecting the lock-in questions), and with improving energy security. This would be done via the development of longer term energy plans that backcast energy system targets from 2050.  These 2050 plans need not be legally or politically binding on Member States. In fact they should not be; both to to allow for frank and open scientific discussion of the challenges and opportunities for different Member States, and to allow for updating in the face of changing circumstances.

However, by their existence as reference documents, the "2050 part" of the plans could nevertheless perform a valuable role in providing transparency about the coherence of these strategies with their own 2030 policies. Over time, these longer term plans would hopefully become increasingly utilized by actors at the national, regional and EU level as a basis for discussing challenges for Member states and to develop common solutions.

Finally, an additional value of these plans is that they in principle would allow for the relationships between the different energy priorities of different Member States to be addressed as part of a package. **Ultimately, the main barriers to a stronger ETS carbon price are to be found in these more political concerns. It is therefore important that they are addressed head-on as part of the Energy Union governance process.**

## 4. Conclusions

The EU has made significant progress in the decarbonisation of its power mix to date. A key challenge is now to scale up low-carbon investment to levels consistent with the EU's 2050 decarbonisation goals. This requires integrating these technologies into the market while also respecting the specific and different needs of low-carbon technologies from the market. In many cases, this means adapting the market design and the design of investment support mechanisms to the different economics of these technologies.

The carbon market is not a sufficient tool for doing so based on the current market design(s), since under current power market design(s), there is a fundamental lack of long term price-hedging opportunities that these technologies need if their costs are to be minimised. There is also a need to address other challenges such as the impact of zero marginal cost technologies on marginal price signals during the transition and the need for systemic coordination of deployment, infrastructure and market design changes.

Since low carbon technologies are very capital intensive, cost minimisation of investment in low-carbon technologies will be best advanced by allowing Member states to implement those policies that best reduce the costs of capital for investors these technologies.

There is a range of existing policy tools, including feed-in-tariffs, contracts for difference, loan guarantees, tendering, etc. that are capable of doing this and which could operate alongside the ETS. Experience with these tools shows that, chosen appropriately, they can reduce the cost of capital by 10 to 30% for new investments. Experience also suggests that the design and tailoring of the instrument to specific cases matters much more than the choice of instrument itself. A one-size fits all approach is therefore likely to raise the costs of investment in the EU and thus to work against a basic goal of the internal market, which is to minimise costs and maximise welfare for consumers.

The role of the EU should therefore be to ensure that design of instruments reflects basic principles and experience regarding sound policy design rather than to impose strict rules regarding instrument choices in the name of harmonisation.

Coordination between complementary investment policies for low carbon technologies and the EU ETS should be guaranteed by an explicit role for ex-ante cap adjustment in the ETS in light of Member State investment plans based on the use of non-ETS instruments. Member States' post-2020 national energy and climate plans could be an effective tool for doing so. The combination of complementary policies to mitigate capital costs and the ETS would in turn be effective at limiting or eliminating premia paid to mature low-carbon technologies.

The ETS can and should play a leading role in the decarbonisation of the residual thermal power mix. This conclusion is strongly supported by bottom-up plant-level evidence of fuel-switching and investment/market exit potentials. It is important that the ETS play this role because it is a European instrument and thus can help to ensure consistency and coherence between the actions taken to decarbonise the thermal power mix in different Member States. This is critical to the kinds of regional cooperation that will be needed to decarbonise the European power sector. Nevertheless, we find that there may be a (limited) role for complementary policies to decarbonise the thermal generation mix.

In particular, the uncertainty around the rate at which the ETS surplus will decline suggests that Member States with high shares of thermal generation and particularly lignite in their generation mix may struggle to decarbonise fully by mid-century if the mechanism for doing so is the carbon price alone. Furthermore, in this context, there is already a cause for concern that some Member

States with significant shares of low-carbon power will leave too much effort too late to decarbonise their power sectors. Addressing this challenge will require, at a minimum, transparent and consultative planning and reporting. The new energy plans must therefore set their sights not only on 2030 goals but also integrate a process by which Member States develop decarbonisation strategies to 2050 using a back-casting approach. Longer term plans are critically important as a tool for measuring coherence between short term policies and longer term goals relating to minimising costs for consumers, energy security and decarbonisation.

But planning is unlikely to be enough. Avoiding lock-in risks in key Member States with high coal shares will also require willingness on the part of the EU to confront the political challenges – particularly poorer and coal-intensive Member States – in driving forward a positive decarbonisation agenda for their constituencies. In this context, a potential opportunity created by the Energy Union project is that it brings together different aspects of energy policy that may allow more scope for compromise and reconciliation of differing perspectives and interests among Member States. Further work is required to examine where these opportunities could be best exploited for power market decarbonisation. Once again, the long term planning approach described above could help to reveal these priorities and provide a forum for their discussion.

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# 6. Annex

## 6.1. Assumptions underlying comparison of CCGT and wind farm analysis

**Table 2. CCGT plant assumptions**

| | | |
|---|---|---|
| Installation size | MW | 480 |
| Inflation | % | 2,0% |
| Investment accounting life | years | 30 |
| Construction time | years | 2 |
| CAPEX | k€/MW | 800 |
| Annualised CAPEX | €/MW/year | 57505,61407 |
| full load hours | hours/year | 8000 |
| Fuel cost | €/MWh | 64 |
| thermal efficiency | | 55% |
| O&M cost | €/MW/year | 18000 |
| Carbon emission factor | ton of CO2/MWh of fuel | 0,35 |
| Carbon price | €/ ton of CO2 | 10,0 |
| OPEX | €/MW/year | 558000 |

**Table 3. Coal plant assumptions**

| | | |
|---|---|---|
| Installation size | MW | 750 |
| Inflation | % | 2,0% |
| Investment accounting life | years | 40 |
| Construction time | years | 4 |
| CAPEX | k€/MW | 1400 |
| Annualised CAPEX | €/MW/year | 92380,57686 |
| full load hours | hours/year | 8000 |
| Fuel cost | €/MWh | 37,5 |
| O&M cost | €/MW/year | 50000 |
| Carbon emission factor | ton of CO2/MWh of fuel | 0,8 |
| Carbon price | €/ ton of CO2 | 10,0 |
| OPEX | €/MW/year | 414000 |

**Table 4. Wind farm assumptions**

| | | |
|---|---|---|
| Installation size | MW | 45 |
| Inflation | % | 2,0% |
| Investment accounting life | years | 25 |

| | | |
|---|---|---|
| Construction time | years | 2 |
| CAPEX | k€/MW | 1600 |
| Annualised CAPEX | €/MW/year | 123572,824 |
| full load hours | hours/year | 2250 |
| Fuel cost | €/MWh | |
| heat rate | | |
| variable O&M cost | €/MW/year | 20000 |
| OPEX | €/MWh/year | 20000 |
| Carbon emission factor | ton of CO2/MWh | |
| Carbon price | €/ ton of CO2 | |

## 6.2. A classification of design elements for RES-E support

**Table 5. A classification of design elements for RES-E support**

| INSTRUMENT-SPECIFIC DESIGN ELEMENTS | | |
|---|---|---|
| **FIT** | **Periodic revisions** | Support levels are revised (for new plants) periodically |
| | **Traditional degression** | A pre-set reduction of support levels over time for new plants. |
| | **Flexible degression** | The reduction in support levels over time depends on the total installed capacity in a previous period (year, quarter or month). |
| | **Othercost-containmentmechanisms** | Capacity, generation and total budget caps. |
| | **Time-specificFITs** | A demand-dependent FIT which adjusts to the load (demand) situation: it provides a greater remuneration at times of higher demand. |
| **FIP** | **Fixed** | FIP payments can be designed to be constant, e.g. as a fixed, predetermined adder. |
| | **Sliding** | The premium varies as a function of the spot market electricity price) (Couture et al 2010). Also called floating or contract-for-differences. The tariff is guaranteed as target-price and paid out in the form of an adjusting add-on to the market price so that the market price is topped-up (or reduced) to the guaranteed price (Kitzing et al 2012). |
| | **Cap and floor** | Total support (price of electricity + premium) might be capped. Under a floor, a minimum level of support is guaranteed. |
| **Quotas with TGCs** | **Banding (carve-outs)** | Banding can be implemented through carve-outs or through credit multipliers. Under carve-outs, targets for different technologies exist, leading to a fragmentation of the TGC market, with one quota for the mature and another for the non-mature technologies. |
| | **Banding (credit multipliers)** | Under credit multipliers, more TGCs are granted per unit of MWh generated for immature technologies compared to mature technologies.<br>The alternative to banding is obviously no use of carve-outs or credit multipliers. |
| | **Minimum prices** | Minimum TGC prices guaranteed to ensure a minimum level of revenue to the investors. |
| | **Maximum prices (fixed penalty)** | An appropriate penalty is set above the marginal costs of the marginal technology which sets the TGC price. |
| | **Maximum prices (market-price-related penalty)** | An appropriate penalty is set above the marginal costs of the marginal technology which sets the TGC price. |
| | **Banking.** | Banking refers to the possibility to use TGCs issued in one specific |

| | | |
|---|---|---|
| | | year to comply with RES-E targets in a future year. |
| **Tenders** | **Pure price-based auctions vs.multi-criteria auctions** | Pure price-based auctions, with the price as the only award criterion. Multi-criteria auctions, where the price is the main criterion and additional prequalification requirements represent additional criteria (e.g. local content rules, impact on local R&D and industry, environmental impacts)(Held et al 2014). |
| | **Sealed bid / descending clock / hybrid.** | Under sealed-bid auction, project developers simultaneously submit their bids with an undisclosed offer of the price at which the electricity would be sold under a power purchase agreement. An auctioneer ranks and awards projects until the sum of the quantities that they offer covers the volume of energy being auctioned. Under the multi-round descending-clock auction, the auctioneer offers a price in an initial round, and developers bid with offers of the quantity they would be willing to provide at that price. The auctioneer then progressively lowers the offered price in successive rounds until the quantity in a bid matches the quantity to be procured. Hybrid models may use the descending clock auction in a first phase and the sealed-bid auction in a second phase (IRENA 2013). |
| | **Pay-as-bid /vs. uniform price.** | There are basically two different ways to set support levels. Underuniform pricing all winners receive the strike price set by the last bid needed to meet the quota. Under the pay-as-bid alternative, the strike price sets the amount of generation eligible for support and winners receive their bid. |
| | **Penalties for non-compliance or delays** | Penalties can take different forms: termination of contracts, lowering of support levels, shortening support periods by the time of the delay, confiscation of bid bonds guarantees or penalty payments. Regarding the later, they can be in the form of a fixed amount (the Netherlands) and modulated by the delay (Denmark, India). They can be set per MW (Quebec, Peru, India, Argentina), per kWh (Denmark) or as a % of the investment made (Brazil)(see del Río and Linares 2014 and Held et al 2014 for further details). |
| | **Pre-qualification criteria** | They are required to participate in the bidding procedure and checked at an early stage of the bidding procedure. They can refer to: specifications of the bid/offered project, such as technical requirements, documentation requirements and preliminary licences or to the bidding party and require certifications, proving the technical or financial capability of the bidding party (Held et al 2014). |
| | **Regularity/periodicity of auctions** | Existence of a long-term schedule for regular auctions with sufficient anticipation (i.e., 3 years, depending on the technology). |
| | **Minimum number of bidders.** | Seller concentration rules might be implemented (as in California, India and Portugal) in order to mitigate the risk of market power. |
| | **Pre-approved list of technology-specific sites** | A pre-approved list of technology-specific renewable energy sites is approved before the bidding procedure (see del Río and Linares 2014 for further details). |
| | **Price ceilings** | In order to limit the cost of support, the auctioneer can set a ceiling price for each technology, above which projects are not considered (IRENA 2013). |

## 6.3. Assessment criteria used in the energy and climate policy literature (with a focus on renewable energy policies)

**Table 6. Assessment criteria used in the energy and climate policy literature (with a focus on renewable energy policies).**

| Source | Assessment criteria being considered |
|---|---|
| **BEYOND2020 project (del Río et al 2012)** | Effectiveness, cost-effectiveness, dynamic efficiency, equity, environmental and economic effects, socio-political acceptability, legal feasibility |
| **Görlach (2013)** | Effectiveness (is a policy achieving its objectives?), cost-effectiveness (are the effects achieved at least cost?), feasibility (what is the risk of policy failure?) |
| **IRENA (2014)** | Effectiveness,efficiency (static and dynamic), equity, institutional feasibility |
| **IPCC (Mitchell et al 2011)** | Effectiveness,efficiency, equity, institutional feasibility. |
| **Konidari and Mavrakis (2007)** | Environmental performance (direct contribution to GHG emission reductions indirect environmental effects), political acceptability (cost efficiency, dynamic cost efficiency, competitiveness, equity, flexibility, stringency for non-compliance), feasibility of implementation (implementation network capacity administrative feasibility, financial feasibility). |
| **Oikonomou and Jepma (2008)** | Effectiveness, efficiency, impacts on energy and market prices, impacts on society (equity), innovation. |
| **BMU (2005)** | Ecological effectiveness, investment security, socially acceptable, cost efficiency, administrative effort, openness |
| **Madlener and Stagl (2005)** | -Consideration of the impact of RES-E along all sustainability dimensions.<br>-Reduction of adverse environmental and social impacts and increase in short-term economic efficiency.<br>-Development and promotion of a variety of technologies.<br>-Use of participatory processes. |
| **State Aid Guidelines impact assessment (EC 2014)** | Effectiveness in RES-E deployment (success in deploying RES, achievement of targets), static efficiency (encouraging the deployment of those RETs that currently display the lowest costs), dynamic efficiency (long-term potential of new/innovative technologies, source diversification, deployment of non-mature RETs, promotion of continuous technical improvements with a long-term perspective), regulatory risk of changing the support scheme, risks for RES-E producers, minimization of the distributive effects on competition, administrative costs (administrative burdens on both RES-E producers and national administrations), minimization of policy costs (reduce the support per unit of energy produced + control of total support costs), market exposure (exposure to market signals and the wholesale electricity price, increase in the volume of RES-E participating directly in the market and in balancing markets, compatibility with electricity markets), total policy support costs, policy-induced risks for investors and administrative costs. |

Source: Own elaboration.

## 6.4. Overview of renewable energy support policies by country (EU)

**Table 7. Overview of renewable energy support policy types by country in the EU**

| | FIT | FIP | Quotas withTGCs | Tenders | Net metering | Taxdeductions/ exemption | Inv. subsidies | Soft loans |
|---|---|---|---|---|---|---|---|---|
| Austria | √ | | | | | | √ | |
| Belgium | | | √ | | | √ | √ | |
| Bulgaria | √ | | | √ | | | | √ |
| Cyprus | √ | | | | | | √ | |
| Czech Rep. | √ | √ | | | | | √ | √ |
| Denmark | | √ | | √ | √ | √ | √ | √ |
| Estonia | | √ | | | | √ | √ | |
| Finland | | √ | | | | | √ | |
| France | √ | | | √ | | | √ | |
| Germany | √ | √ | | | | | | √ |
| Greece | √ | | | | | √ | √ | |
| Hungary | √ | | | | | | √ | |
| Ireland | √ | | | | | √ | | |
| Italy | √ | √ | √ | √ | √ | √ | | |
| Latvia | √ | | | | | √ | √ | |
| Lithuania | √ | | | √ | √ | | √ | √ |
| Luxembourg | √ | | | | | | √ | |
| Malta | √ | | | | | √ | √ | √ |
| TheNetherlands | | √ | | | √ | | √ | √ |
| Poland | | | √ | | | √ | √ | √ |
| Portugal | √ | | | √ | | √ | | |
| Romania | | | √ | | | | √ | |
| Slovakia | | √ | | | | √ | √ | |
| Slovenia | √ | √ | | | | | √ | √ |
| Spain | √ | √ | | | | √ | | |
| Sweden | | | √ | | | √ | √ | |
| U.K. | √ | | √ | | | √ | | |

Source: del Río and Mir (2014).

## 6.5. Modelling inputs into fuel switching analysis

**Table 8. Modelling inputs into fuel switching analysis**

| | ES | UK | RO | PL | IT | DE | CZ | Total |
|---|---|---|---|---|---|---|---|---|
| **Power mix (capacity - MW)** | | | | | | | | |
| Gas | 25774 | 36062 | 2912 | 210 | 42122 | 14940 | 668 | |
| Coal | 10027 | 21500 | 1288 | 18798 | 13728 | 26672 | 1116 | |
| Lignite | 1763 | 0 | 4537 | 9628 | 0 | 19489 | 7807 | |
| Oil | 0 | 0 | 0 | 0 | 6035 | 2169 | 0 | |
| Gas/Coal | 0 | 280 | 136 | 1946 | 6229 | 814 | 0 | |
| **Total** | **37564** | **57842** | **8873** | **30582** | **68114** | **64084** | **9591** | |
| | | | | | | | | |
| Average thermal power demand (MW) | 9696,05251 | 23680,1163 | 2877,30491 | 15876,5728 | 17852,8113 | 36608,2364 | 4708,13002 | **111299,224** |

**Table 9. Lignite prices assumptions for each country**

| | Lignite Price | |
|---|---|---|
| Germany | 1,855 | €/GJ |
| Poland | 2,625 | €/GJ |
| United Kingdom | 4,777 | €/GJ |
| Italy | 2,3 | €/GJ |
| Czech Republic | 1,645 | €/GJ |
| Romania | 3,085 | €/GJ |
| Spain | 2,3 | €/GJ |

## 6.6. Robustness of fuel switching results to other policies (LCDP and german EPS)

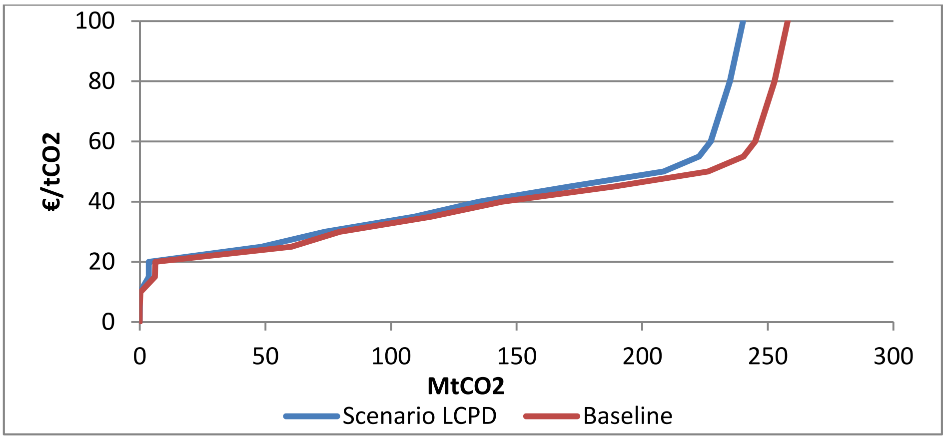
The fuel switching results presented above also appear to be robust to the influence of other policies that could affect the existing thermal capacity generation capacity of these Member States. For instance, Figure 16 below shows the impact on the MAC curve presented above if all of the plant given temporary opt-outs from the revised Large Combustion Plant Directive (part of the « Industrial Emissions Directive » package of legislation) are closed at the end of 2015 (which in principle is what the Directive requires). The figure shows two scenarios: one has been constructed with the actual operational capacity in the "medium prices" hypothesis  (called "baseline"); in the other we assumed that the total capacity of the power stations listed in the LCPD directive is closed (Scenario LCPD).

The overall impact of the LCDP found here is actually quite small. This partly reflects the limited amount of capacity affected in many of these markets. It also reflects the fact that countries with the largest amount of capacity to be closed, such as Poland – which should need to close between 3-9 GW of capacity – have quite limited fuel switching potential based on existing capacity.

It is important to note that our analysis models only those plants given opt-outs and which must be closed before 2016 under the current LCDP standards. However, additional plant may close due to the combination of current standards and CO2 prices. For instance, it is unclear which plants required to retrofit based on current performance standards will decide to do so. If carbon prices are high enough, the combined cost of compliance with the current standards and the CO2 price are expected to lead to some additional closure decisions. This would tend to lower the prices at which the CO2 price could phase out coal, flattening the marginal abatement cost curve further and raising the fuel switching potential.

Furthermore, standards that will apply to existing large combustion plants from 2019 have yet to be defined, however these standards are likely to represent a further tightening of existing standards and thus additionally lower the price of CO2 at which these plant will be driven out of the merit order and closure decisions may be made. Unfortunately, a comprehensive analysis of the expected impact of these factors is impossible based on current political uncertainties. However, it is worth recalling that the typical view that an ETS does nothing below a carbon price of 45€/tCO2 is unlikely to be true once one takes into account these policies.

**Figure 16. Abatement potential from fuel switching taking into account the impact of the LCPD in 7 key Member States**




As a further robustness check, the potential impact of an emissions performance standard or strategic reserve in Germany was also examined. The results are presented in Figure 18 below. The scenarios analyzed included different ambitions of coal plant closures ("scenario EPS" and "strengthened EPS") and the nuclear power plant closures. We assumed that these scenarios take place in the beginning of 2020, that the demand is lower than it was in 2013 and that the share of renewables continue to increase to reach the 2020 German RES objectives. Once again, a significant residual potential for fuel switching was found to exist in all scenarios.

As this paper is being written, the primary option on the table for achieving Germany's 2020 targets is a policy whereby an increasing carbon charge would be applied to generation units over 21 years of age which produce beyond a minimum threshold each year. Compared to the scenarios analyzed here, this option would tend to increase the relevance of the ETS for driving out these plant from the system. Indeed, it would function not unlike the impact of the UK carbon price floor described above.

Figure 17. Robustness checks on impact of possibleGerman EPS and nuclear phase out for role of ETS to drive fuel switching

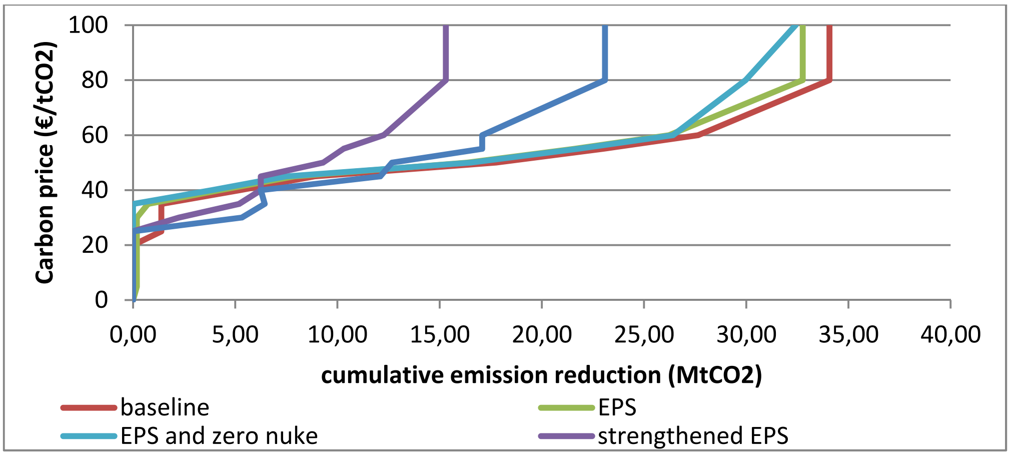



Table 10. Assumptions included in the different scenarios

| Figure 18. Impact of a German EPS on the emission abatments. The scenarios have been buildt as follow: | Baseline | EPS | Strengthened EPS | EPS and 0 nuke | Strengthened EPS and 0 nuke |
|---|---|---|---|---|---|
| Coal power plant closures | 0 | 4 GW | 10,5 GW | 4 GW | 10,5 GW |
| Share of renewables | Same as 2013 (25%) | Same as 2013 | Same as 2013 | 45% | 45% |
| Share of nuclear power plants | Same as 2013 (15%) | Same as 2013 | Same as 2013 | 0 | 0 |

## 6.7. Assumptions underlying investment analysis in Section 3.1.3

Table 11. Assumptions underying investment analysis in Section 3.1.3

| | FC/MW (EUR) | FC/MWh (EUR) | VC/MWh (CO2=0) (EUR) |
|---|---|---|---|
| | | | |
| New Coal plant cost | 173798 | 19,84 | 24,22 |
| New Gas plant cost | 97170 | 11,09 | 46,52 |
| Existing Coal plant cost 0.35 EFF | 50000 | 5,71 | 31,13 |
| Existing Coal plant cost 0.3 EFF | 50000 | 5,71 | 36,32 |
| Existing Coal plant cost 0.38 EFF | 50000 | 5,71 | 49,24 |

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