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NEW ENERGY FINANCE

# Emission performance standards

## Impacts of power plant $CO_2$ emission performance standards in the context of the European carbon market

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# Executive summary

This brief report assesses the impact on new power plant build and the EU Emissions Trading Scheme (ETS) of a $CO_2$ emission performance standard (EPS) set to prevent new coal or lignite-fired power stations from coming online unless they are fitted with Carbon Capture and Storage (CCS).

The analysis conducted in this report finds that even under conservative assumptions on the development of the European carbon market the implementation of an EPS post 2020 would have very little impact. The main reason for this is that with the EU ETS in place, virtually no new coal or lignite units without CCS would be built in the future beyond those projects already under development.

In Western Europe a simple cost analysis shows that by 2020 there is no economic rationale for building coal plants over Combined Cycle Gas Turbines (CCGTs). This is even the case without a carbon price. In Eastern Europe which historically has had lower coal and lignite prices than Western Europe, building coal fired power stations plants is only viable under €5/t carbon price.

With coal subsidies being phased out across Europe, increasing public opposition to new coal-fired stations in some regions, and the very strong likelihood of carbon prices being in excess of €20/t by 2020, one would expect very few new coal-fired stations to be built at all after 2020.

An early EPS, starting in 2015, would under current conditions of the European carbon market have more of an impact as the analysis shows some new coal capacity being built between 2015 and 2020. An EPS introduced in 2015 would affect some projects currently under development, which would otherwise likely be completed.

However, the analysis also shows that implementing an EPS in 2015 would not produce any material benefits in terms of reducing greenhouse gas emissions or deploying CCS technology and would lead to slightly higher abatement costs and higher imported gas dependency for the EU.

# Section 1. Introduction

The purpose of this report is to assess the impact of introducing a CO2 Emission Performance Standard for new build power stations on power station build rates and the EU ETS as a whole. It has been prepared at the request of the European Commission by Bloomberg New Energy Finance.

Whilst the purpose of the EU ETS is to reduce emissions to below a specific cap over a period of time, it has been argued that the carbon price within the EU ETS may not be sufficient to prevent the construction of coal or lignite fired power stations. This might occur because emission reductions from short term abatement measures - e.g. the effects of the recession or the import of carbon credits from outside the EU – or reductions in other sectors might be sufficient to achieve the targets whilst still allowing the development of some coal and lignite stations. In the long run this might then “lock-in” the European power sector to high carbon emitting technologies.

One way of preventing this “lock-in” would be to ban the construction new coal and lignite power stations without CCS through the enforcement of a performance standard on CO2 emissions. The standard would set the emissions limit at a level such that only coal or lignite stations with CCS, or other low emitting technologies, would be allowed.

The analysis presented in this report uses the European module of the Bloomberg New Energy Finance Global Energy and Emissions Model (GE2M). The original version of the model was developed between 2005 and 2008 to model future carbon prices in the EU Emissions Trading Scheme. This was subsequently integrated into a global framework (GE2M) to produce carbon price and emissions forecasts across multiple zones around the world.

The model is a partial equilibrium model covering all the main energy using sectors across the EU and worldwide. The EU power sector is modelled in the most detail and has been calibrated based on verified EU ETS emissions as well as detailed installation databases on power sector assets.

In the power sector, decisions on the development of new power generation capacity are made endogenously in the model, taking into account engineering costs, fuel prices, environmental constraints and more qualitative policy objectives. The model methodology is explained in more detail in Section 2 and Appendix 1.

The rest of this report is structured into four sections:

- Section 2 sets out the methodology and main assumptions underpinning the analysis, covering forecasts of power demand, new-build capacity and project economics.
- Section 3 presents the results of the modelling to show the effect of an EPS on power station investment decisions.
- Section 4 draws out the key conclusions.
- Appendix 1 provides a more detailed description of the GE2M model.

# Section 2. Methodology

## 2.1. Overview

Our approach to assessing the impact of an EPS on power sector investment decisions uses two main steps:

1. Development of a business as usual scenario to show the expected evolution of the European power fleet in terms of new generation capacity needed and the type of plant built.
2. Assessment of how this evolution will change with an EPS – introduced either from 2015 or from 2020.

In both cases assumptions have been made about the need for new generation capacity and the factors affecting the choice of generation technology. These inputs are described in more detail in the rest of this sector.

## 2.2. New build decisions

The first step in determining the evolution of the EU power generation fleet is to understand what new capacity would be built under current regulations and market conditions. One key factor affecting the new build decisions is the current EU ETS framework which sets a price on carbon emissions from large stationary emission sources including power stations.

### New build requirements

The extent to which additional fossil fuel-fired power generation capacity will be required in the EU is determined by:

- net demand growth for electricity from the grid
- existing generation plant retirement
- renewable and nuclear build.

#### Electricity demand

In GE2M national electricity demand is projected considering economic growth, energy efficiency improvements, development of embedded generation and elasticity of power demand to power prices.

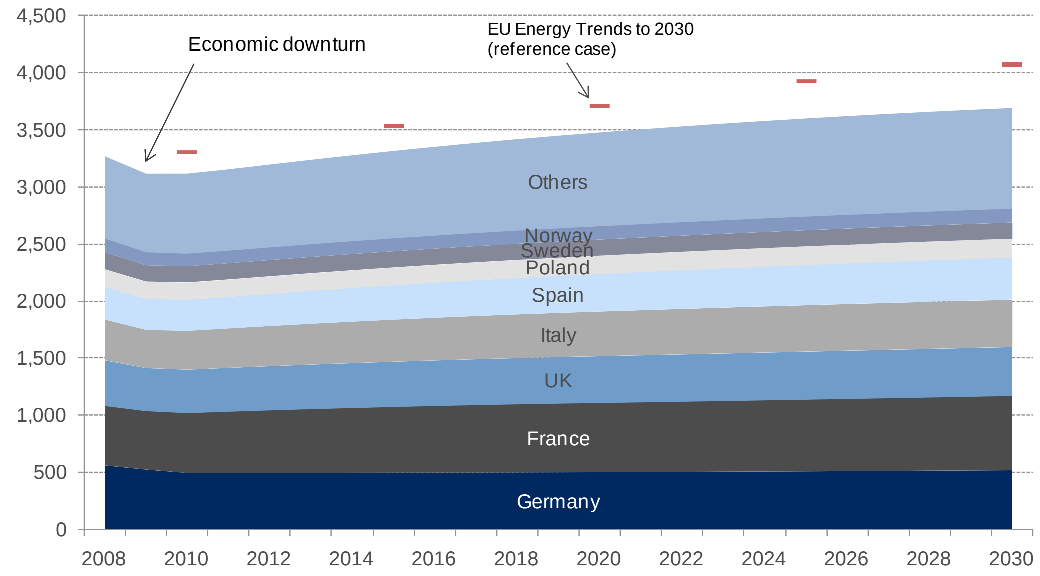
For all Member States, national electricity demand is first projected exogenously using historical relationships between historical power demand and GDP growth. For all countries for which the data was available, growth in power demand was regressed on GDP growth over the period 1990 to 2009[1] and projected out to 2030 considering the October 2010 IMF GDP forecast[2].

Adjustments due to the expansion of embedded generation, improvements in energy efficiency and the elasticity of power demand to power prices are then applied to these projections in order to reflect electricity sector developments and existing policy requirements. As a result of this analysis, electricity demand in the EU is expected to increase by 18% from 2009 levels to 3,697TWh in 2030 (Figure 1).

This compares to a projection of a gross electricity demand of 4,037TWh in 2030 under the reference case of the 2009 update of *EU Energy Trends to 2030*[3]. The Bloomberg New Energy Finance estimates are 9% lower than the EU Energy Trends projections for 2030.

[1] Electricity demand data was taken from Eurostat, and GDP (historical and projections) from the International Monetary Fund (IMF). A shorter time period had to be used for some CEE countries for which power demand in the early 90s was not available.
[2] AS the IMF growth projections only go out to 2015, growth rates were held constant at 2015 levels for the period 2016-2030
[3] http://ec.europa.eu/energy/observatory/trends_2030/index_en.htm

**Figure 1: Gross electricity demand in the EU27 and Norway (TWh per annum)**

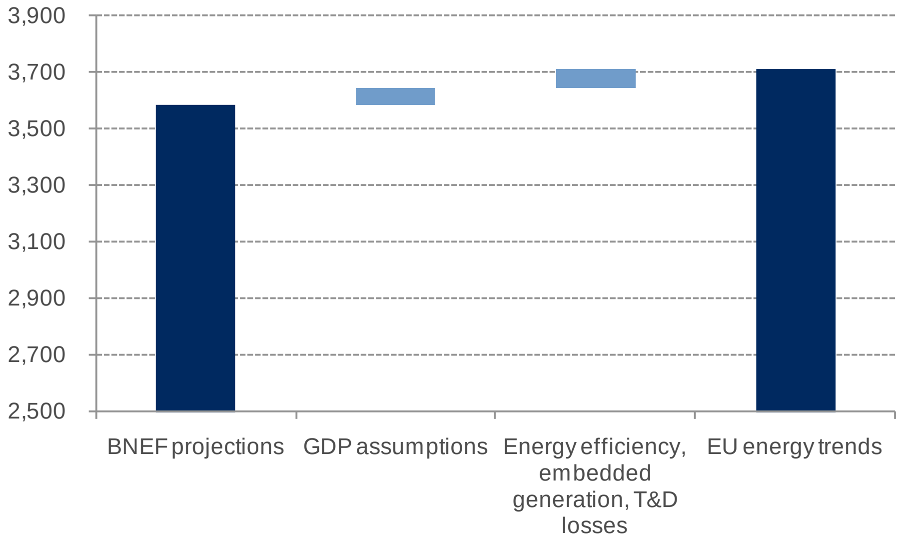



*Source: IMF, Eurostat, Bloomberg New Energy Finance, DG for Energy*

The main reason for the difference in projections is the lower GDP growth assumptions used by BNEF. This particularly applies to the early years of the study which are lower than those given in the 2009 EU Energy Trends report, reflecting the negative influence of recent developments in the European economy such as the debt crisis in some EU countries and the impact of fiscal austerity measures in many countries.

Differences in GDP assumptions however only partially explain the difference. The BNEF projection also assumes greater improvements in electricity intensity of the European economy than in the EU Energy Trends report, for example through improvements in network operations, and refurbishment, and roll-out of embedded generation (Figure 2).

**Figure 2: Difference in BNEF, and EU energy trends to 2030 gross electricity demand forecasts**




*Source: IMF, Eurostat, Bloomberg New Energy Finance, DG for Energy*

### Installed capacity projections

Whilst theoretically the choice between alternative power generation technologies should be driven by their relative long-run cost of energy (LCOE), in reality other factors also come into play: (i) the desire of utilities and governments to deploy a diverse portfolio of plant to manage risk in an uncertain world and (ii) government policies to support the development of high cost generation technologies, eg renewables and nuclear power.

Consequently the penetration of renewable and nuclear generation capacities are assumed to be driven by exogenous policy factors rather than simply their relative costs, and their growth remains constant across the scenarios explored here. Therefore the impact of an EPS is assessed with regard to the fuel mix of new build plant between the fossil fuel technologies – principally coal versus natural gas.

Essentially the demand for new *fossil fuel* power stations is given by the difference between the capacity needed to meet demand (with an appropriate capacity margin) and the installed capacity available after having taken into consideration:

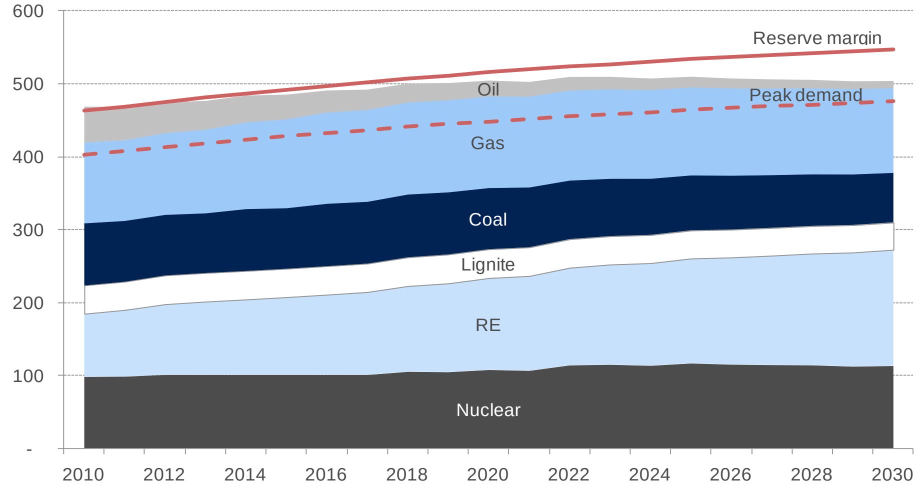
- the retirement of the existing fleet - based on expected lifetimes of specific plant types, national phase out policies (mainly for nuclear) or emissions policies (such as the Large Combustion Plant Directive)
- nuclear capacity projections - based on information on government support, cost constraints, public perception, etc.[4]
- policies and targets driving renewable power investments
- power plant under construction or at an advanced stage in the development process, or demonstration plants for instance for CCS or ultra-supercritical coal-fired plants.

The result of this analysis is shown in Figure 3. This shows the projected evolution of *available* power generation capacity in the EU-27 (incl. Iceland and Norway) if no new fossil plants are built between now and 2030 against projected power demand. "Available capacity" is shown here rather than "installed capacity" because what matters for meeting demand is the amount of power that can be generated at any point in time. The difference between the two is the load factor, which was calculated for each country and technology based on historical performance.[5] In terms of demand a reserve margin is added to "peak demand" to allow for safety margin in meeting demand under all eventualities.[6]

*Some 43GW of new fossil-fuel capacity will be needed by 2030 to meet electricity demand.*

In short, the overall available capacity growth in renewable energy and nuclear power is projected to broadly offset the retirement of fossil plants over this period resulting in a relatively stable available capacity. However with power demand expected to continue to grow across the EU approximately 11GW of additional capacity will needed by 2020 and 43GW by 2030.

**Figure 3: EU-27 + Iceland + Norway peak demand and available capacity (GW)**




*Source: Bloomberg New Energy Finance.*

It is not possible to be precise about exactly where new capacity will be needed and built due to uncertainty around national power demand projections and the development of interconnectors between Member States. The UK, Germany and France are likely to see some of the largest new capacity additions because of the need to replace aging plants as well as meet new demand.

[4] The assumptions and rationale behind Bloomberg New Energy Finance's forecast of nuclear capacity are detailed in a separate Research Note published on the Impact of nuclear Power on the EU ETS on 30th June 2010.
[5] Load factors were calculated using Platts, Eurostat and ENTSO-E data.
[6] The peak demand level is the expected maximum level demand reached across the year dependent on national policies – for example in the UK it is common to consider the 1-in-20 highest demand level – ie, the level of demand associated adverse weather conditions that would be expected to occur once every 20 years.

### 2.2.2 Coal vs. gas

The choice between coal and gas generation is mainly driven by economic considerations: given the choice, a utility would chose to build a CCGT over a coal-fired power plant if the latter had a lower levelised cost of energy. The following shows how the LCOE for a generic CCGT and a generic supercritical coal-fired plant compare and could vary across the EU.

**Methodology**

The levelised cost of energy (LCOE) is the discounted lifetime cost of a generating one unit of power (typically MWh) from a particular plant type taking into account all capital and operating costs. The main components of the LCOE are

- Capital costs. These relate to the development and construction of the plant. For gas and coal-fired power plants, technology costs constitute the large share of the total capital costs which thus aren't expected to vary significantly for a plant built in the UK, or in Poland. Civil works account for about 15% of the total costs, and the difference in land and labour costs will be accounted for in the low and high cost used in the following analysis.
- Operating costs. These cover the costs of maintaining an operational workforce, materials, spares and bringing specialist services for repairs, insurance and grid charges. Because of the labour cost differential between Western and Eastern Europe, different fixed operating costs are modelled.
- Fuel costs. These depend on the efficiency of the plant and the prevailing fuel prices. Fuel costs can vary greatly from one country to the next. In countries such as Germany, Greece, Poland and other Eastern European countries, the coal and lignite mining industry provides a cheap and stable supply of fuel while the UK has to rely more on imports.
- Carbon costs, depending on the carbon intensity of the plant and market carbon prices. Bloomberg New Energy Finance conducted a survey of the largest European utilities in 2009 and found that 100% of the respondents factored in a carbon price in the investment decisions, and 90% of the respondents believed in a long-term carbon price.

**Assumptions**

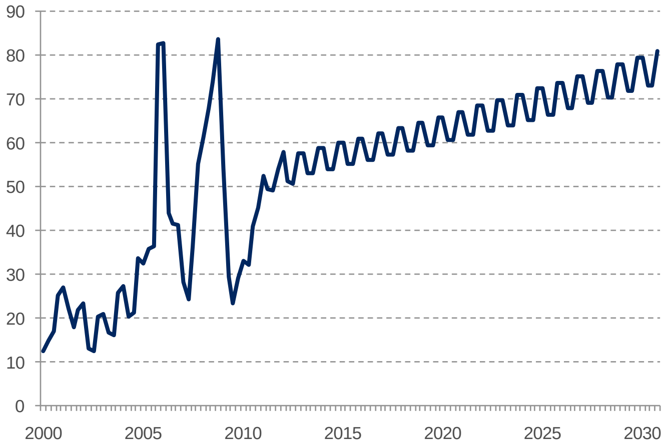
When calculating the LCOE for each technology, low, central and high costs scenarios were considered to reflect different market conditions across the EU. The low, central and high cost scenarios coincide with rates in use respectively in Eastern Europe, Western Europe (including South Europe), and Scandinavia.

For all regions, a 59% efficiency was assumed for the CCGT plant, with a load factor of 70% over 25 years. The supercritical coal plant was assumed to operate at an efficiency of 44% with a load factor of 70% over 40 years. The costs for the flue gas desulphurisation and selective catalytic reduction systems for coal plants needed to meet Large Combustion Plant Directive emission limits are included in all costs presented below.

Fuel prices projections for Western Europe and Scandinavia are assumed to follow the market forward curve as of 30 November 2010 (Figure 4 and Figure 5). Due to an abundant domestic supply of coal in most Eastern European countries, power plants are subject to lower coal prices in this region. The EIA's international data on steam coal prices for electricity generation shows that the discount between Polish steam coal prices and the average price for Western Europe[7] were between 59% and 68% during 2005-2008 with an average discount of 64%. For the purposes of the modelling, Eastern European coal price projections were therefore determined using a 64% discount on the Western European price assumptions.

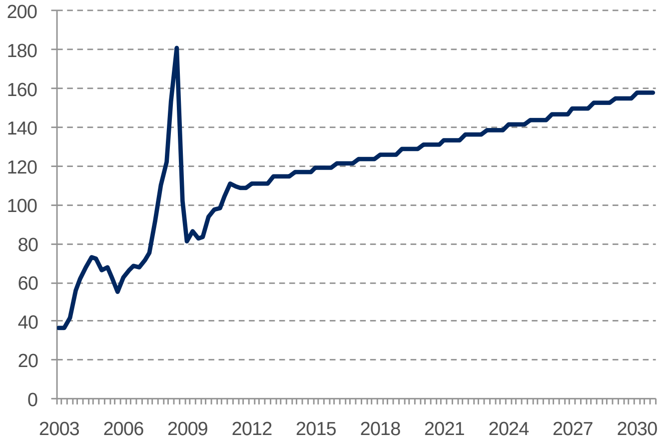
[7] Average calculated using data for Austria, Belgium, France, Germany and the UK. Other EU-27 countries were excluded because of lack of data availability.

**Figure 4: Natural gas prices (nominal), central assumption (p/therm)**




*Source: Bloomberg, Bloomberg New Energy Finance Note: Historical and forward curve based on the NBP front month contract*

**Figure 5: Coal prices (nominal), central assumption (USD/tonne coal)**




*Source: Bloomberg, Bloomberg New Energy Finance Note: Historical and forward curve based on the ARA coal front year contract*

Capital and operating costs have been taken from Mott MacDonald's June 2010 *UK Electricity Generation Costs Update* using data for the Western Europe case. Eurostat data on hourly labour costs for 2008 shows that Polish and Danish hourly rates are equivalent to respectively 31% and 138% of the rates in the UK. The Eastern European and Scandinavian numbers were derived by considering this difference in labour cost affecting 15% of the central cost, which coincides with the share of the total cost due to civil work. A nominal discount rate of 10% was assumed for all technology types. The resultant LCOEs are shown in Table 1 and Figure 6 for a plant constructed in 2020 under different carbon prices.

**Table 1: Components of the LCOE for an installation in 2020 (€/MWh)**

| LCOE components | CCGT | | | Supercritical coal | | |
|---|---|---|---|---|---|---|
| | Eastern Europe (Low) | Western Europe (Central) | Scandinavia (High) | Eastern Europe (Low) | Western Europe (Central) | Scandina via (High) |
| Capital costs | 13 | 14 | 15 | 29 | 33 | 35 |
| Operating costs | 7 | 8 | 9 | 13 | 15 | 16 |
| Fuel costs | 46 | 46 | 46 | 21 | 33 | 33 |
| LCOE (no carbon price) | 66 | 69 | 70 | 64 | 81 | 84 |
| LCOE (€20/t carbon price) | 75 | 77 | 79 | 83 | 100 | 103 |
| LCOE (€40/t carbon price) | 83 | 86 | 88 | 102 | 119 | 123 |
| LCOE (€60/t carbon price) | 92 | 95 | 96 | 122 | 139 | 142 |

*Source: Mott Macdonald, Bloomberg New Energy Finance*

### 2.2.3 Comparison of the LCOE of coal and gas

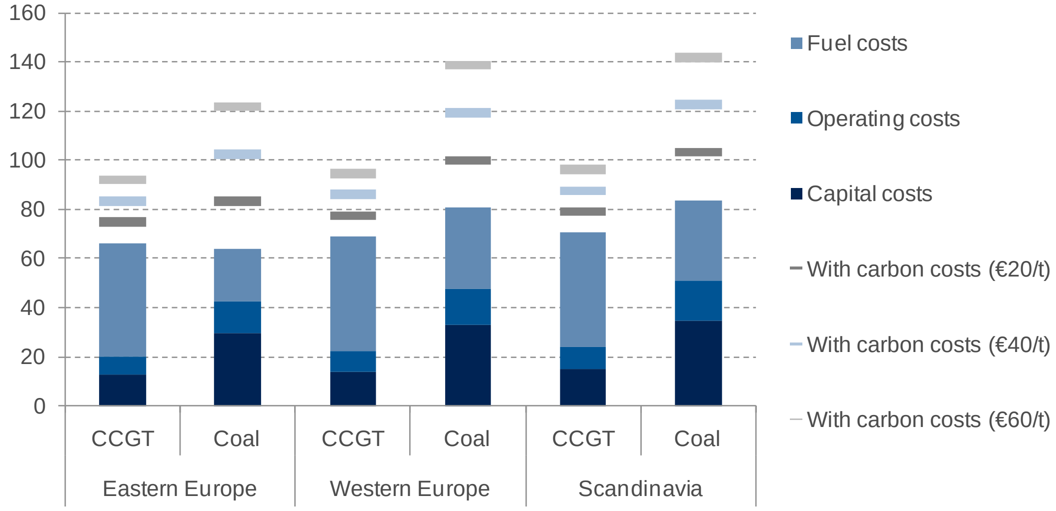
On the basis of the assumptions stated above, the analysis highlights two key points.

- In Western Europe (which includes Southern Europe) and Scandinavia without a carbon price, the levelised cost of generating power from new build CCGTs is lower that for coal plants in 2020 implying that CCGTs would be built in preference to coal even without the carbon price. The cost advantages in favour of CCGT increase with the introduction of a carbon price. At carbon prices of €20/t and €40/t CCGT technology becomes 28% and 32% respectively cheaper than coal on a levelised cost basis.
- In Eastern Europe without a carbon price high efficient coal is cheaper than CCGT technology. This is mostly due to cheaper fuel costs as assumed above, although labour costs also play a role (coal plants have a higher proportion of labour costs than CCGT). However once carbon prices are introduced coal is disadvantaged.

*For carbon prices higher than €5/t CCGT new build is economically more attractive than coal in all EUETS countries.*

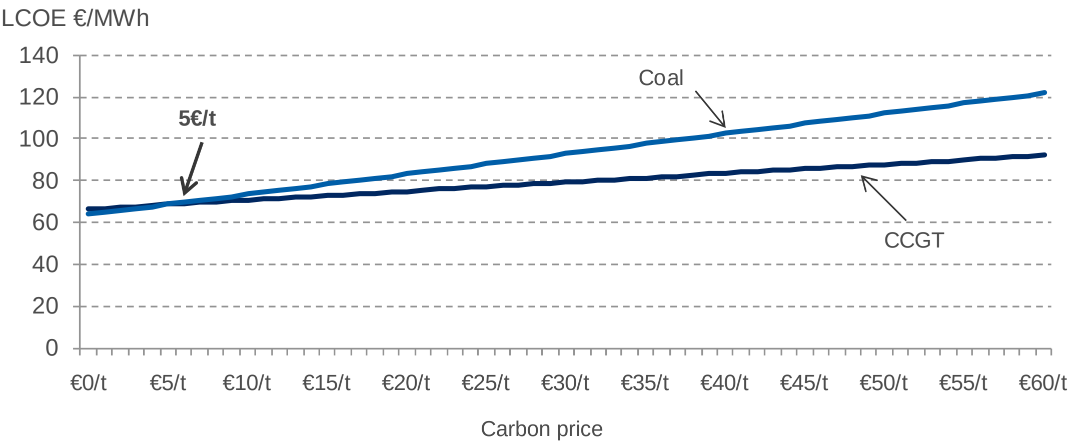
Figure 7 compares the LCOEs for CCGT and coal in Eastern Europe at different carbon prices. It shows that at a €5/t carbon price CCGTs become cheaper than coal. This implies that at current EUA prices (around €15/t) CCGT would even be preferred to coal plants in Eastern Europe.

**Figure 6: LCOE for an installation in 2020, per region and cost component (€/MWh)**




*Source: Bloomberg New Energy Finance*

**Figure 7: LCOE for CCGT and coal generation in Eastern Europe (€/t)**




*Source: Bloomberg New Energy Finance*

### 2.2.4 Impact of auctioning

The move to greater use auctioning of EUAs to the power sector, particularly in Western Europe, from 2013 should not affect the relative decisions of investing coal and gas stations when compared with an alternative of a free allocation based on a single carbon emissions benchmark (CO2/MWh). Irrespective of the level of the benchmark providing a single benchmark is used for all generation technologies, the lower carbon intensity of CCGT technology will benefit it over coal under free allocation and full auctioning.

### 2.2.5 Methodology used for capacity projections

A full description of Bloomberg New Energy Finance's Global Emissions and Energy Model ($GE^2M$) is provided in Appendix 1. However, in the context of this analysis the most relevant calculations are those pertaining to future capacity projections, which are described below.

Three types of capacity change are forecast on an annual basis:

- *Closures*: reductions in capacity due to retirements or early decommissioning
- *Transitions*: adapting either the configuration or processes within existing capacity
- *New build*: adding new capacity to the sector to ensure capacity sufficiently exceeds demand.

### Closures

Plants retirements are forecast assuming an average lifetime per generation technology. Without life extension, a coal-fired power station is expected to run for about 40 years, whilst a CCGT would last for 25 years. However, if a class of plant is not utilised for several years it may be closed prematurely subject to requirements to maintain an adequate capacity margin.

### Transitions

We use the term ‘transitions’ to describe retro-fitting new technologies to old plants, refurbishment of existing operations and adjustments to operational management of the asset, where the performance of existing capacity improves.

The transitions analysis is also used for forecasting complete decommissioning of old plants and replacement of them with, effectively, new build. This occurs in extreme situations where the short-run marginal cost of the incumbent class exceeds the long-run marginal cost of a replacement class.

The model considers the fitting of Carbon Capture and Storage, and/or the rehabilitation of existing plants as potential options when projecting future installed capacity.

### New build

New build is added to each country where the installed capacity is below the assumed minimum capacity margin. For the volume of new build that is required, the split between generation technologies is driven by their relative levelised cost of electricity (LCOE). The simplest approach would be to choose the least cost in each sector, with new build inserting more capacity in whichever class has the lowest LCOE. However this ignores the portfolio benefits of having a diverse range of generation technologies within the fleet – ie it may be desirable to maintain investments in a range of generation technologies even though one technology is clearly the cheapest. To accommodate these effects GE²M allows the capacity added to be spread across a set of 5 technologies with similar cost levels.

This means that even in a situation where CCGTs were the most cost-effective technology, GE²M could still ‘build’ coal-fired stations or wind farms if these were in the top five technologies.

It is worth noting that the fuel and carbon price assumptions used in the LCOE calculations correspond to the market prices at the time the decision is made. This means that even if the model forecasts a very high carbon price for 2020, a plant built in 2012 will only ‘see’ a carbon price rising at the cost of carry from its 2012 price. Therefore it is assumed in the model, as it is often in reality, that long-term investment decisions are made with limited foresight into the future. The price curve considered therefore does not reflect the strengthening of the EU ETS cap and is thus bullish when looking at new coal and lignite build, which become decreasingly desirable due to their high carbon intensities.

### Constraints

The cost-driven modelling of capacity evolution in GE²M leaves open the possibility of sweeping changes to key sectors in each country, not all of which might be reasonable in view of other non-cost aspects of real-world developments. Policy is an important aspect of this, which prohibits some technologies while mandating others. Country-specific resource constraints are also important, for most sectors, as are the sociological traditions that have developed in different places.

For this reason all capacity calculations are performed within a framework of constraints on the minimum and maximum levels that certain technologies can reach, both in absolute and percentage terms. For instance GE2M currently assumes no new nuclear capacity would be allowed in Germany, Ireland or Austria, that are specifically anti-nuclear. Similarly renewable energy capacities are forecast separately for each country and technology.

### Implications for coal vs gas generation decisions

*Our methodology considers economics, policies and national preferences when projecting future capacity, and is enhanced in the short to medium term by taking into account new plant announcements.*

Although GE²M is a fundamental economic model, the methodology used allows for ‘non-economic’ build. The model will not only build the least cost technology but spread new capacity requirements across technologies considering economics, national preferences and policies.

Since tradition or support to the coal industry can be more relevant drivers than economics or policies in heavily regulated markets, this methodology might not be best fitted to adequately forecast new capacity in Eastern European markets. This is why Bloomberg New Energy Finance follows new plant announcements to ensure that our short to medium-term forecast is as close to reality as possible. We believe that our projections to 2020 are in line with utilities and countries’ announcement.

When looking at a longer time-frame, namely the period 2020-2030, it is assumed that deregulation and the development of an internal energy market will help markets evolve towards a more homogenous and economic-driven environment. Our methodology thus fits the market conditions the EU will be subject to post 2020.

## 2.3. Base case without an EPS

### 2.3.1 Assumptions

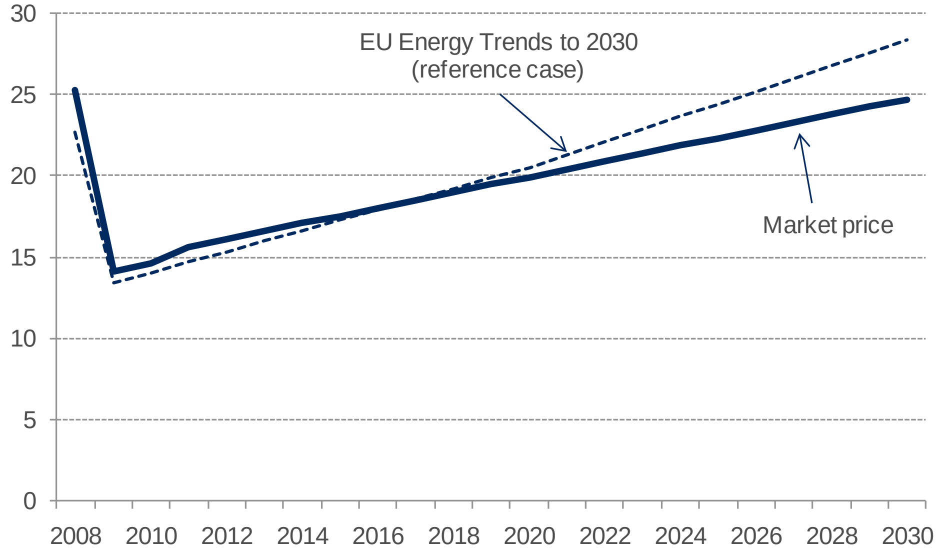
Using Bloomberg New Energy Finance's Global Emissions and Energy Model ($GE^2M$), the EU ETS was modelled with the following assumptions:

- A 21% Phase III emissions reduction target for 2020 – consistent with the already pledged 20% overall reduction in EU emissions by 2020 relative to 1990 levels.
- For 2021-2030, a linear extrapolation of the annual emission reduction target from Phase III of 1.74%.
- No additional CDM allowed for ETS compliance beyond 2020 and no banking of CERs or ERUs from 2020 into Phase IV.
- Fuel prices and legacy capacity assumptions are consistent with what was presented in Section 2.
- Carbon prices following the market forward curve as of September 30, 2010.

Although the model produces independent projections of carbon prices, the prices used in this analysis are a simple extrapolation of the current market forward curve for EUAs. This is because the future European carbon price is still highly uncertain and extreme prices could dominate the analysis in this study. Assuming the current market price accurately reflects all future knowledge about the EU ETS, extrapolating the current market price is a viable way of assessing the effect of an EPS on the European power sector. In the current context it can also be interpreted as conservative assumption on the development of European carbon markets to avoid overestimating effects of carbon prices in the analysis of the impacts of an EPS.

The assumed carbon prices are shown in Figure 8 together with the carbon prices in the reference case presented in the 2009 update of European Commission DG Energy's *EU energy trends to 2030* report. The prices assumed in our analysis rise to €20/t (€16/t 2009 real) in 2020 and €25/t (€16/t 2009 real) in 2030[8].

**Figure 8: Assumed carbon prices (€/t)**




*Source: Bloomberg New Energy Finance*

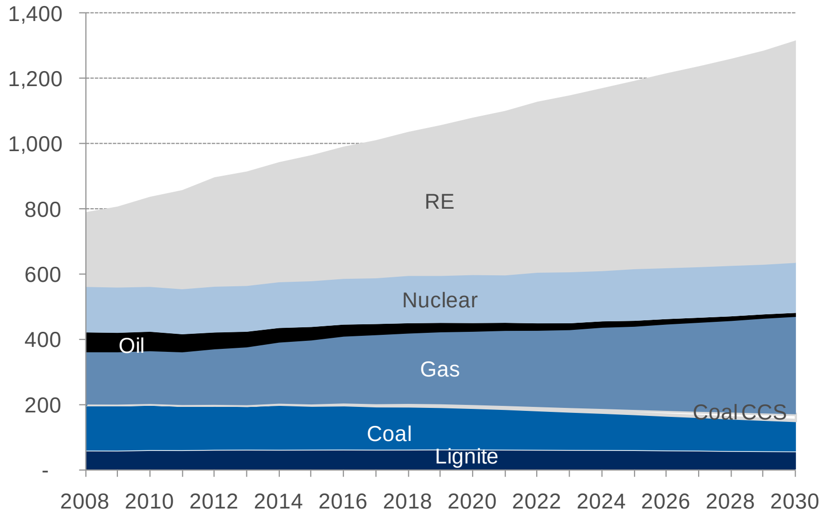
[8] The assumption that no international offsets are allowed for use in the ETS from 2020 necessitates the deployment of relatively expensive domestic abatement options

### 2.3.2 Plant build

*No new coal or lignite fired plant are projected to come online post 2020 considering current market prices for EUAs.*

Even considering these relatively low projections, no new coal or lignite-fired plant without CCS are expected to come online after 2020, when prices rise above €20/t. However, we do project new 15GW of coal and lignite-fired power plants to be built between 2015 and 2020 (Figure 9). These new plants are expected to be built in Belgium, Bulgaria, Czech Republic, Germany, Greece, Italy, Norway, Poland and Romania.

**Figure 9: Installed capacity (GW)**



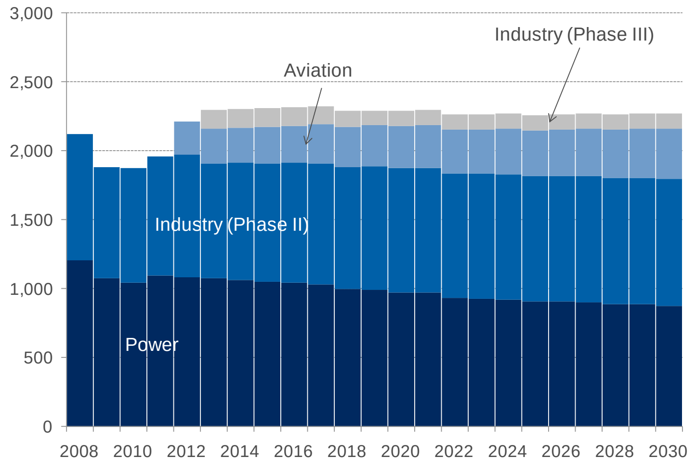

*Source: Bloomberg New Energy Finance*

### 2.3.3 Emission projections

Overall power sector emissions are expected to reduce by 27% in 2030 compared to 2008. This is due to the uptake of renewable power, sustained use of nuclear, deployment of CCS, greater use of natural gas relative to coal and enhanced energy efficiency (Figure 10 and Figure 11). The projection has 18GW of CCS capacity coming online by 2030, mostly through the retrofitting of existing coal plants.

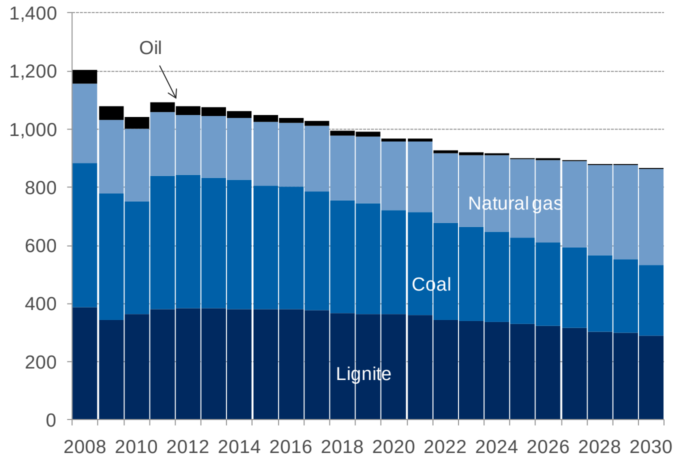
Coal and lignite are expected to gradually move from base to peak generation due to higher carbon prices and these legacy plant being displaced in the merit stack by newer renewable, nuclear and gas units. The timing of this transition depends on how exposed power stations are to international fuel prices - ie whether they face an international (ARA) price or a lower domestic coal prices.

**Figure 10: EU ETS emissions[9] (Mt)**




*Source: Bloomberg New Energy Finance*

**Figure 11: Power sector emissions in EU ETS countries (Mt)**




*Source: Bloomberg New Energy Finance*

[9] Emissions from aviation are included in the ETS scope in 2012, and further industrial process emissions are covered from 2013.

# Section 3. Impact of an EPS

As no new coal plant without CCS is projected to be built post-2020 under our base case, the introduction of an EPS from 2020 for new build has very little effect on emissions and prices. An EPS starting after 2020 is therefore deemed redundant as it would only act as a precautionary measure in case market participants did not believe in long-term carbon price signals.

Considering an Emission Performance Standard on new coal and lignite-fired generation assets being developed without effective CCS from 2015, we find the following results.

- The 15GW of new coal and lignite capacity projected to come online between 2015 and 2020 under the base case is prevented and is replaced, in the 2015 EPS scenario, by 10GW of CCGTs (Figure 13)[10]. An early EPS would accelerate the replacement of coal and lignite capacity by CCGTs.
- There is little difference between the base case and 2015 EPS scenarios in terms of CCS deployment; the difference in coal CCS installed capacity projected for the two scenarios remain below 1GW over the whole 2010-2030 period (Figure 13).
- Power sector emissions under the 2015 EPS are projected to be on average 10Mt/yr and 28Mt/yr below emissions for the base case for Phase III and Phase IV (2021-2028) respectively. This is because lower coal capacity leads to lower coal-based generation, and subsequently higher gas-fired generation (Figure 14).
- Natural gas demand is consequently projected to increase on average by 2,047Mtherms/yr and 4,407Mtherms/yr in the EPS case compared to the base case for Phase III and Phase IV respectively. The higher use of natural gas under the 2015 EPS case compared to the base case would increase European fuel dependency with regard to imported natural gas.
- Because the EU ETS cap is identical under the base and the 2015 EPS case, total EU ETS emissions would remain the same were an EPS to be implemented in 2015. The difference is that as power sector BAU emissions are slightly lower with a 2015 EPS, demand for abatement is lower which will induce slightly lower carbon prices - although the effect is somewhat moderated by the effect of slightly higher abatement costs under the 2015 EPS (see next bullet). This in turn means industrial and aviation emissions would be higher by an equivalent volume (given a fixed cap).
- A 2015 EPS would result in abatement costs that are slightly higher than without the EPS - which as noted above partly but not completely offsets the downward price effect of lower demand under the EPS. This is because the EPS removes some abatement options from the abatement cost curve, such as switching out of coal to gas or adding CCS to the coal plants. Without these abatement options the abatement cost curve is slightly higher than the equivalent curve without an EPS.

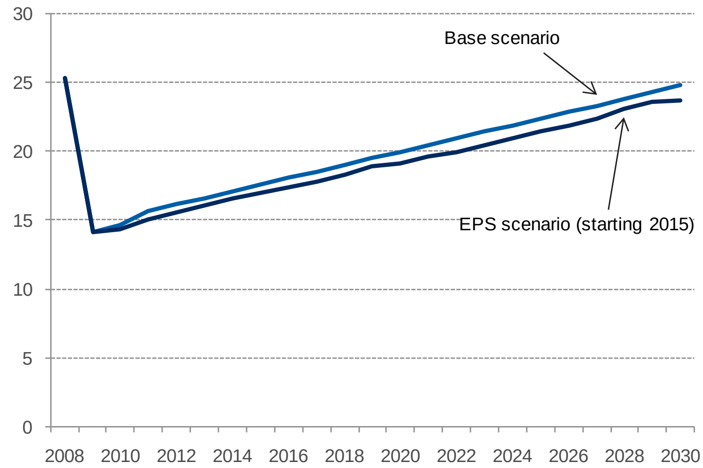
Given the results of this EU level analysis, the impact of a single large EU Member State setting an EPS would be negligible if applied from 2020 onwards, and similar but on a smaller scale if applied earlier depending on how much new capacity is projected to be installed.

It should also be noted that these conclusions were reached considering a conservative carbon price track. If ETS carbon prices were to be higher, for instance due to economic recovery being more vigorous than assumed, or if a target more stringent than the current 20% emission reduction target were adopted, the expected new coal build would be lower. Consequently the impact of an EPS on coal fired generation pre-2020 would be smaller.

[10] The coal new built is principally based on new plant announcements, input into the model, whilst the gas new capacity is mainly projected by the model to meet a capacity margin of 15% in all countries. This explains the difference of 10GW between coal built under the base case, and 5GW of CCGT in the EPS case.

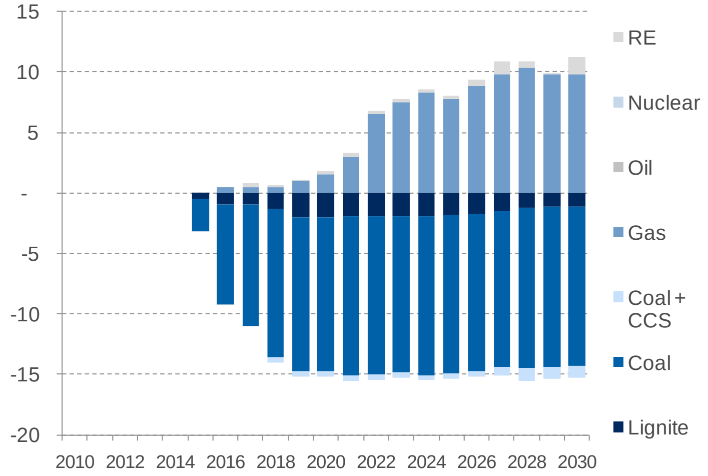
 

**Figure 12: Impact on carbon prices (€/t)**



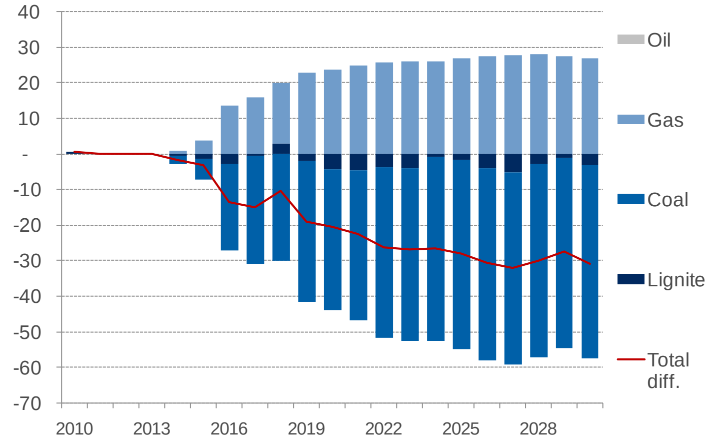

*Source: Bloomberg New Energy Finance*

**Figure 13: Difference in installed capacity (GW)**



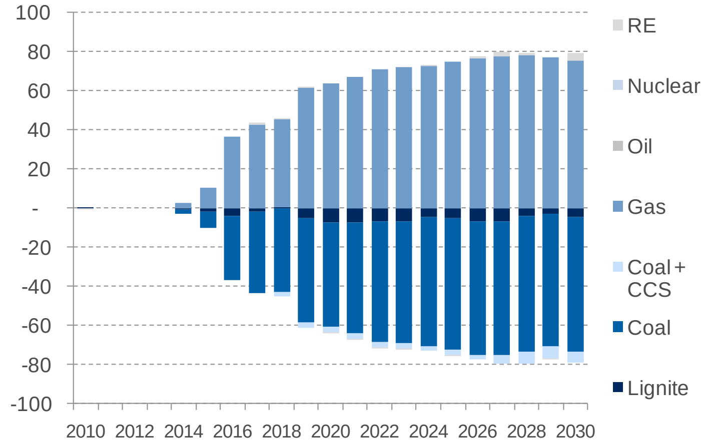

*Source: Bloomberg New Energy Finance*

**Figure 14: Difference in power emissions (MtCO2e)**




*Source: Bloomberg New Energy Finance*

**Figure 15: Difference in power generation (TWh)**




*Source: Bloomberg New Energy Finance*

# Section 4. Conclusion

The analysis conducted in this report finds that the implementation of a CO2 Emission Performance Standard for power plants post 2020 would have very little impact. The main reason for this is that with the EU ETS in place, very few new coal or lignite units without CCS would be built in the future.

As well as the simple economics for building new plants which shows that CCGTs have lower life time costs than coal even in Eastern Europe at carbon prices around €5/t, coal subsidies are being phased out across Europe, and there is increasing public opposition to new coal-fired stations in some regions. Even without the EU ETS one would expect very few new coal-fired stations to be built.

An early EPS, starting in 2015, would have more of an impact on new build decisions as the modelling shows some new coal capacity being built between 2015 and 2020. An EPS would prevent these projects from being completed.

However, the analysis also shows that implementing an EPS in 2015 would not produce any material benefits in terms of reducing greenhouse gas emissions or deploying CCS technology and would lead to higher imported gas dependency for the EU.

# Appendix 1 Global Energy and Emissions Model description

## Overview

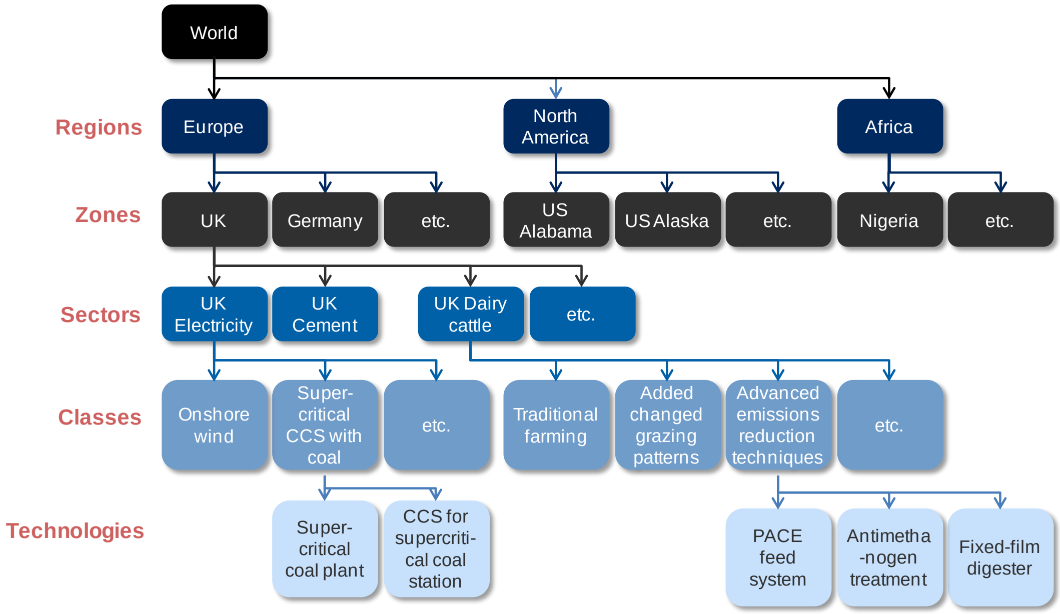
GE²M is a tool for simulating the future development of energy- and emissions-intensive sectors of the economy across all parts of the world. The model is used for projecting CO2 emissions and carbon prices, and the impact of policies at a regional and national level on these outputs.

Carbon markets affect forecasts for all aspects of the modelled sectors. Thus in turn carbon prices can be forecast by finding the carbon price levels at which the modelled behaviour is consistent with carbon market constraints. Emission projections are a key output from GE²M, as are capacity and output levels split by the class of technology or operational practice. There are many derived secondary outputs including investment levels in particular technologies and demand for particular fuels.

### Data structure

In GE²M, data is arranged in a hierarchy as shown in Figure 16.

**Figure 16: Structure of the world as modelled in GE²M**




*Source: Bloomberg New Energy Finance*

**Regions** are the larger geographical unit in GE²M, roughly corresponding to continents. The six regions are North America, Latin America, Europe, Africa, Asia and Oceania. All data is grouped within a specific region, and some inputs, especially default values for economic behaviour assumptions, are actually set at region level. Additionally, a framework has been built for modelling scenarios in which global trade is affected by changes in costs, for which the distinction between regions is important,[11] and the analysis of electricity grids is performed one region at a time.

**Zones** are the smaller geographical unit in GE²M. Mostly these are individual countries, such as EU Member States, but zones have been defined to correspond to different types of political entity depending on the level of detail required in the analysis. Zones in the US and China are states and provinces respectively, but some other developing countries are grouped, such as 'OtherAfrica'. A less detailed approach is taken for geographies where less data is available or the forecasts are of less interest – eg, geographies where historical emissions have been extremely low.

[11] Changes in costs may be caused by carbon pricing, so the trade analysis could be used to develop scenarios involving carbon leakage. However, our current assumptions neglect trade effects, as any forecast of material changes in trade flows will require close scrutiny. We plan to develop robust assumptions on parameters affecting trade in dedicated research at a later date.

**Sectors** in GE²M are different types of activity that consume energy and/or result in GHG emissions. Power and heavy industry are important sectors that have been included in previous carbon models produced by Bloomberg New Energy Finance, but some of the other modelled sectors such as parts of agriculture, transport and building climate control are now treated in much more detail.

*Classes are the key concept that underpins abatement forecasts in GE²M*

**Classes** are the different types of operation that can (or could) run within a particular sector. The real-world significance of classes is sector-dependent. As such, classes in the power sector broadly correspond to types of power station, and classes in dairy cattle represent a specific set of operating practices in the management of dairy cattle herds. Data specified at the class level relates to operational performance: carbon intensity, fuel demand per unit of output, and other components of short-run cost. Qualitatively, different classes involve the deployment of different sets of technology which are also specified as inputs.

**Technologies** are the building blocks of the classes. Data in GE²M grouped at the technology level is concerned with investments: the components of the capital cost, with the land and labour components disaggregated where significant, along with lead times and a maximum payback time (usually the equipment lifetime).

### Calculations

*The analysis of carbon fundamentals in GE²M draws on a broad-scope economy model*

In every sector in every zone, the evolution of capacity from year to year is forecast in response to the economic drivers and any other constraints. The most important aspect of this forecast is the changing penetration over time of the different classes within the total capacity, as new build (new power stations, new buildings, new factories, etc), retro-fitting and closure forecasts mean some classes become increasingly dominant while others fall out of favour. The economic drivers of changes in capacity combine the operational costs (defined for each class) and the capital costs (associated with the underlying technologies).

The levels of emissions, fuel and electricity demand in every sector are the product of forecast levels of output multiplied by the operational performance of each class. Therefore, estimating the change in capacity utilisation by class – ie, the production split – is an important next step after forecasting the capacity split. In some sectors competition between different producers means the best operations run close to maximum capacity while inefficient operations run lighter with significant spare capacity.

The analysis of short-term production splits is especially important in the relatively liberalised power sectors of some developed countries, which are analysed in the most detail within GE²M. Fuel switching is also analysed for power sectors in parts of the world with less liberalised power markets or less data availability, although in these cases a more aggregated approach is used for producing forecasts.

The combined forecasts of capacity investments and productions splits over long periods of time produce a simulation of the overall development of all the energy- and emissions-intensive sectors across the global economy. Fundamental carbon price forecasts can be produced from this model because the simulation responds to carbon prices. In other words, the optimisation approach searches for the carbon price levels at which all linked schemes clear. This is done in the context of the market foresight assumptions which define what is meant by 'clearance' over a period of time.

## Forecasting carbon prices

The rules of carbon pricing schemes, including linkages between different schemes, are inputs to the model. For any particular set of carbon prices, the economy simulation can be run and emission forecasts extracted. Testing the behaviour of emissions as a function of carbon pricing is the basis for fundamental carbon price forecasting.

This analysis therefore relates to the use of static marginal abatement cost curves (MACCs). Carbon price forecasts are produced using static MACCs by first estimating emissions in the absence of a carbon price, calculating 'demand for abatement' as the difference between the emissions and the effective cap, and reading off the required price on a plot of abatement against price.

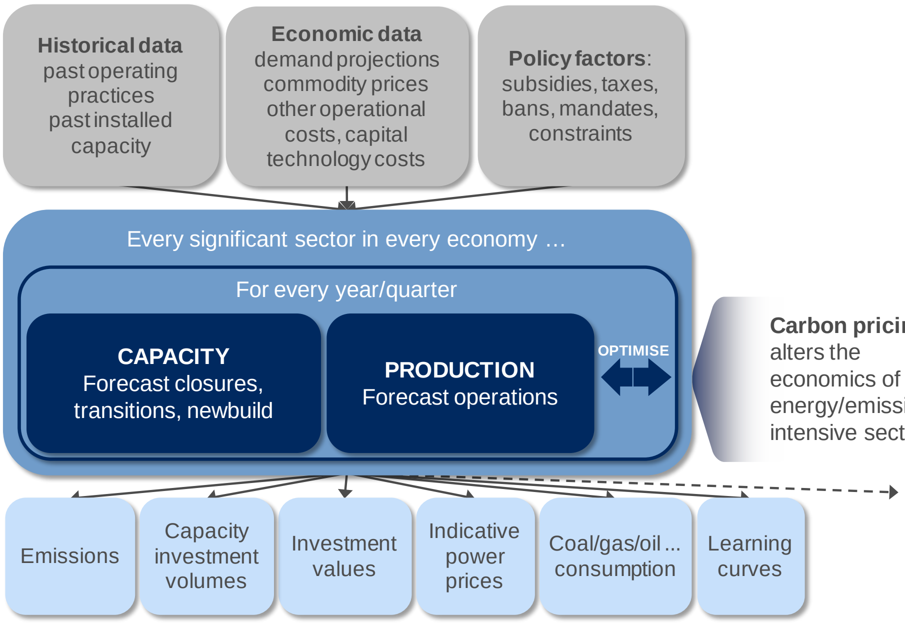
The principal difference between GE²M and the use of static MACCs is that any implicit 'MACCs' in GE²M are dynamically determined throughout the model simulation. As such the modelled behaviour should respond appropriately depending on the trajectory of carbon prices as well as their level at any single point in time. This is important because the options available at later stages in the simulation (eg, after 2020) depend on the modelled decisions taken earlier in the simulation (eg, before 2020) – this issue is known as 'path dependency'.

## Forecasting emissions

The economic model is the core component of GE²M, for which historical capacity and production levels in every sector split by class provide initial conditions. Then future capacity and production are forecast in response to economic inputs, some of which may be adjusted due to policy inputs, while ensuring agreement with constraints on the practical set of feasible outcomes (Figure 17).

The main model result is a set of class splits in every sector for both capacity and production in every modelled year. From these class splits many derived outputs can be calculated. From the perspective of forecasting carbon prices the most important output is GHG emissions, which feeds back into the carbon price optimiser

**Figure 17: Schematic of economy and emissions forecast**




*Source: Bloomberg New Energy Finance*

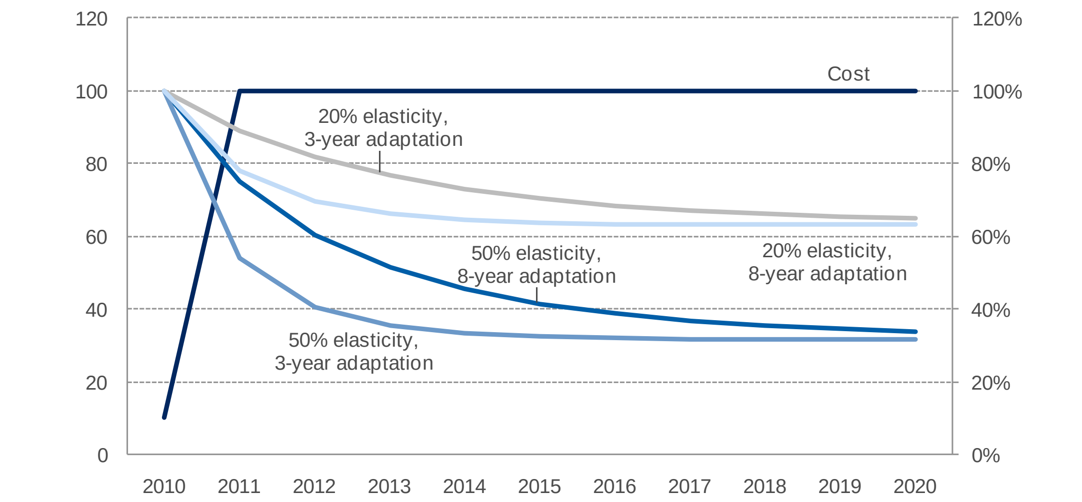
## Forecasting demand

'Price neutral' demand forecasts for every sector in every zone are entered based on exogenous analysis such as regressions against population and GDP by sector specialist analysts. Additionally, elasticity coefficient and time constant assumptions are entered for each sector.

The elasticity calculation is similar to a price elasticity of demand. However, rather than price the elasticity effects are calculated from average costs across each sector, except in the case of power sectors that are modelled in greater detail with approximate power price forecasts driven off the marginal short-run generation costs found during power scheduling.

An 'elasticity adaptation time' assumption is used to reflect the assumption that elasticity effects may only become significant over extended multi-year periods of time. The modelled demand responds to costs rising to levels that are consistently higher than historical levels adjusted for inflation. The full elasticity effect is phased in gradually depending on the adaptation time (see Figure 18).

**Figure 18: Comparison of demand responses to a tenfold increase in real costs for 20% and 50% elasticity coefficients with 3- and 8-year adaptation times**




*Source: Bloomberg New Energy Finance*

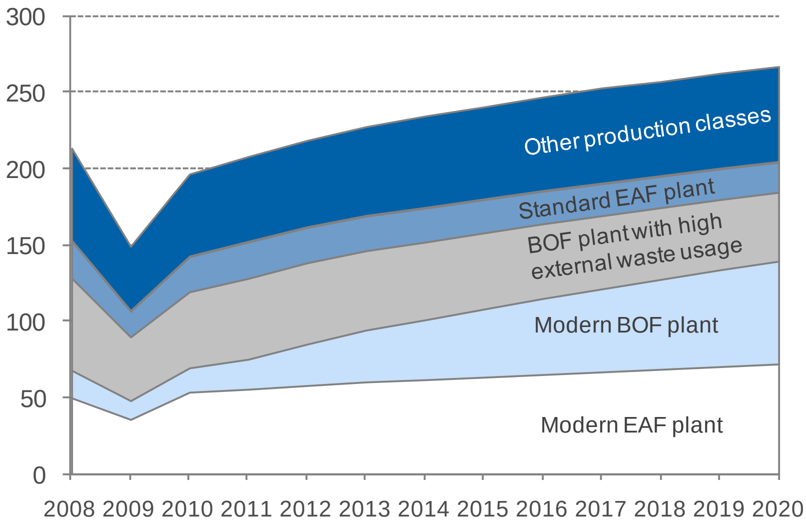
## Forecasting capacity

Three types of capacity change are forecast on an annual basis in every sector:

- *Closures*: reductions in capacity due to retirements or early decommissioning
- *Transitions*: adding new technologies or changing the management of existing operations
- *New build*: adding new capacity to the sector to ensure capacity sufficiently exceeds demand.

These three stages in capacity evolution are discussed here with reference to non-power sectors. Figure 19 shows an example of forecast class capacity splits over time for European steel.

**Figure 19: EU steel production forecast by class (Mt)**




*Source: Bloomberg New Energy Finance*

### Closures

In most sectors closures associated with plant retirements are forecast with an 'attrition' assumption giving the fraction of the capacity that will turn over on an annual basis, which is applied pro rata across all class. This is not ideal because in practice some classes tend to have been built later than others. But the main purpose of the attrition is to reflect the overall churn in the sector. If a specific class is expected to be entirely out of service by a certain date, this can be entered as a constraint, explained at the end of this section.

'Early closures' are the other means by which capacity is reduced. Capacity in classes that goes unused according to historical production inputs and future production forecasts closes at a faster rate than the standard attrition rate. This is set up such that after *n* years (specified as an input) 90% of any capacity that is consistently unused will have closed. However, the early closures only happen while there is still excess capacity above the minimum capacity margin specified for the sector.

**Transitions**

*The new transitions analysis enables us to produce more realistic forecasts of non-power-sector abatement*

We use the term 'transitions' to describe retro-fitting new technologies to old plants, refurbishment of existing operations and adjustments to operational management, where the performance of existing capacity improves. Thus existing capacity 'transitions' from one class to another.

The transitions step in capacity evolution is the most important aspect of changes over time for most modelled sectors. In the case of buildings, for example, there are many countries where the volume of building stock is approximately static, and demolition rates are low. As such the main changes to the performance of the building stock over time are upgrades to what is already there. The same applies to much of European industry, where improvements can be made to existing factories.

The improvement in GE²M is modelling levels of penetration of different classes across each sector. The original installation level data is converted into the initial class split by assessing the technologies already deployed. We then model changes in the class split over time, allowing for smoother changes in the rates of technology uptake.

The size of the economic driver of any particular transition is given by:

*transition driver = yearly operational cost saving – annualised capital cost of equipment*

where the cost of equipment refers to whatever additional technology needs to be added to move from the old to the new class. Rather than modelling this as a discrete switch, where transitions with positive drivers immediately occur, the rate of transition (the fraction of capacity to which the transition is applied) is treated as being proportional to the transition driver, with a constant of proportionality consistent with historical behaviour in the sector. Calibration of this constant does not require the historical existence of carbon markets, because the transitions analysis responds not only to carbon but to all changes in cost (eg, fuel prices also drive transitions).

A final adjustment is made to increase the transitions rate on the basis of the combined share of total sector capacity of the classes being moved 'from' and 'to'. We do this because of the effect on search costs where a particular improvement becomes widely known, meaning in effect that a specific technological improvement gains momentum, which is an important aspect of the typical s-shaped uptake curves seen in most markets when new technologies emerge.

The transitions analysis is also used for forecasting complete decommissioning of old plants and replacement with, effectively, new build in extreme situations where the short-run marginal cost of the incumbent class exceeds the long-run marginal cost of a replacement class.

**New build**

New build is added to sectors where the capacity in the initial conditions is below the minimum capacity margin, or where capacity drops below due to plant retirements. In sectors where large volumes of new build are required, this part of the analysis is where changes in costs due to carbon can have the largest effect.

For the volume of new build that is required, the split between classes is driven by their relative long-run marginal costs (LRMCs). The simplest approach would be to pick winners in each sector, with new build inserting more capacity in whichever class has the lowest LRMC.

GE²M allows the capacity added to be spread across a set of classes with similar cost levels. A 'cost competitiveness index' is provided as an input, setting the maximum cost where some capacity is still added, as a multiple of the lowest LRMC.

**Constraints**

The cost-driven modelling of capacity evolution in GE²M leaves open the possibility of sweeping changes to key sectors in each country, not all of which might be reasonable in view of other non-cost aspects of real-world developments. Policy is an important aspect of this, which prohibits some technologies while mandating others. Zone-specific resource constraints are also important, for most sectors, as are the sociological traditions that have developed in different places.

For this reason all capacity calculations are performed within a framework of constraints on the minimum and maximum levels that certain classes can reach, both in absolute and percentage terms. In some cases this means that closures, transitions or new build are needed specifically in order to meet a constraint that is changing over time. In this case the specific least-cost way of meeting that constraint (while not violating any others) is identified by the model and applied in the sector.

## Forecasting production

The final emissions forecast are given by:

*emissions = sum over all classes ( production volume × carbon intensity )*

so translating the capacity in each sector into actual output forecasts meeting demand is an essential next step.

For some sectors (eg, refineries) we assume that the distribution of output is relatively insensitive to costs – ie, the extent to which different refineries compete directly is weak – in which case production is assumed to occur across the capacity on a pro rata basis.

However, in other sectors, such as pulp and paper, our assumption is that competition can lead to more efficient plants running closer to full capacity while costlier plants run lighter. In this case a production competitiveness index is assumed which specifies the level of short-run cost relative to the cheapest production class above which classes are assigned no production. This means sectors assumed to be highly competitive have production distributed strictly according to the merit order, while moderately competitive sectors have production spread more widely though still skewed towards cheaper production classes.

## Power sector

### Power capacity

Power sectors are modelled in relatively high detail - plant retirements, retro-fits and new build are applied in volumes reflecting the realistic size of individual generating units. Additionally, the capacity inputs for these sectors can be used as a starting point for the capacity evolution, where some new build and closures are entered specifically by the user to reflect planned capacity changes that have already been reported. Generally, retirements in the power sector are treated strictly by retiring plants that reach the end of the typical operating life, as opposed to general 'attrition rate' assumptions that are applied in other sectors.

### Power production scheduling

*Power scheduling is an important step, especially for cap-and-trade schemes, where we have refined our existing approach*

The main difference between the detailed power sector analysis versus other sectors is in the scheduling of generation to meet demand. The annual electricity demand in each zone is divided into four quarters, with six different load periods representing variation within the quarter for different times of the day/week (overnight, peak, super-peak, extended peak, weekend overnight, weekend daytime). The schedule is found that meets demand at least cost across all time periods. This includes accounting for arbitrage between time periods using power storage.

Interconnector flows between neighbouring zones within each time period are also modelled dynamically. This allows for the possibility of cross-border fuel switching having an impact on pan-European volumes of abatement in the EU ETS. Again, this is a continuation of the methodology used in ECM, which is now applied for analysis across a wider range of countries – eg, US and Australia.

The only material functionality addition for power scheduling in GE²M that was unavailable in ECM are two additional sets of parameters alongside take-or-pay that can be used to adjust the schedule for phenomena that interfere with the short-run marginal cost minimisation:

- 'Take-or-pay' assumptions have always been an important input to our modelling – ie, fractions of the capacity in certain classes that are assumed to operate under conditions where the opportunity cost of fuel is zero (eg, long-term gas contracts).
- 'Grid-constrained capacity' is a different type of adjustment, specifying capacity in a certain class that 'must run' regardless of cost. These types of assumption are required to adjust for the fact that we do not directly the domestic grids inside each zone, and in some zones their internal grid constraints are significant. In GE²M this must-run capacity is flagged before running the main scheduling algorithm and the corresponding share of power demand is removed.
- 'Cheap fuel' assumptions are a new adjustment that can be made in GE²M to set a fraction of a class in a specific country that operates under conditions where fuel sees less than the full market cost of its fuel, although the cost is non-zero (unlike take-or-pay). In our European analysis this type of assumption is particularly useful in assessing the behaviour of lignite-burning plants.

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