STUDY OF THE EU 2030 ENERGY PACKAGE

A report to Olje- og energidepartementet (OED)

December 2014

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TABLE OF CONTENTS

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EXECUTIVE SUMMARY

Pöyry has been commissioned by The Norwegian Ministry of Oil and Energy (OED) to analyse the impact of the 2030 climate package on European power markets. Pöyry has studied the effect of the proposed targets on energy efficiency, CO_2 emissions and renewable energy – first looking at the impact of each target independently, then at the impact of the combined elements.

Pöyry has conducted a detailed quantitative analysis over the period from today to 2030, using four detailed in-house Pöyry models: BID3 modelling the power market over the whole of Europe at an hourly resolution, a carbon model covering the entire EU ETS, a European renewable energy model covering electricity, heat and transport and finally an econometric model of electricity demand in Europe. These four models have been used in order to produce fully internally consistent scenarios taking into account the interaction between the different packages and the potential market reactions on investments. In this study, the different elements of the 2030 package are implemented in a harmonised and cost-effective way.

Pöyry concludes that the 2030 climate package is likely to lead to a very significant transformation of the electricity system, with far reaching consequences all over Europe. Pöyry finds that the carbon price may not vary significantly as a result of the 2030 package, but that wholesale power prices could decrease by more than 30% by 2030 under the combined pressure of renewable and energy efficiency objectives. The continuation of low power prices and low profit margins is likely to result in a continued period of difficulties for utilities, and the problem of ‘missing money’ will need to be addressed both in order to maintain existing plants online and to build new ones where necessary.

Pöyry’s analysis suggests that adopting either the renewables target or the energy efficiency target in isolation may lead to unintended outcomes due to their negative impact on the carbon price. In particular, an unrestricted market outcome could see coal plants being built instead of low carbon technologies, therefore ‘locking’ Europe away from a longer term decarbonisation path. On the contrary, the tightening of the carbon market in isolation would deliver carbon emission reductions by incentivising lower carbon generation (e.g. CCGTs) and investments (in particular nuclear), at the expense of a higher wholesale electricity price.

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DETAILED SUMMARY

As part of the work on Energimeldingen The Norwegian Ministry of Oil and Energy (OED) has requested a study on the impact of future EU energy and climate policies on European power markets. This study will investigate the impact of the proposed policy framework put forward by the European Commission in January 2014: *A policy framework for climate and energy in the period 2020 to 2030*[1]. It was requested that the impact from the components of the 2030 package be assessed individually and as part of a complete package.

Background and approach

The European Union has a long history of coordinating energy policy, with an increasing focus on climate change mitigation. The Renewable directive[2] published in April 2009 set out the 2020 carbon, renewable and energy efficiency targets, and the Energy Roadmap 2050 published in 2011 stated that greenhouse gas emissions should be reduced to 80-95% compared to 1990 levels by 2050.

Continuing the efforts for EU decarbonisation the European Commission proposed in early 2014 an energy policy from 2020 to 2030. The proposal includes the following targets:

- Greenhouse gas (GHG) emission reduction of 40% relative to 1990 levels
- Renewable share of 27% in primary energy demand
- Continued efforts in energy efficiency -indicated at 25%
- Market reform of the Emission Trading System (ETS)
- New governance framework

The overall objective of this study is to assess the effect of implementing the proposed 2030 package on European power, carbon and RES markets.

The study uses detailed electricity, carbon and RES market modelling to identify and describe any challenges – and distortions – that may occur as a result of the package.

The study uses a scenario-based approach to investigate the impact of each of the 2030 targets individually and as part of the full 2030 package. The scenarios studied are:

- **Baseline** (Base) scenario with a “business as usual” assumption with only existing policy framework from 2020 to 2030
- **Energy Efficiency** (EE) scenario with 25% increase in energy efficiency relative to 2007 projections by DG TREN
- **Renewables** (RES) scenario with 27% renewables in primary energy demand
- **Carbon** scenario ensuring a 43% reduction in GHG emissions in the ETS sector
- **Full Package** (FP) scenario combining all the elements of the 2030 package

In this study, the Norwegian Ministry of Oil and Energy guided some crucial assumptions, in particular that the recovery of fixed and investment costs could be realised through the

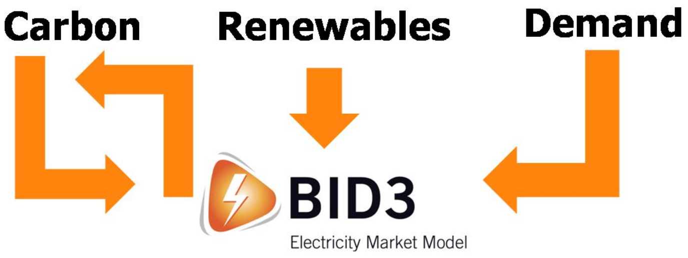
[1] COM(2014) 15 final

[2] Directive 2009/28/EC

peakiness of wholesale prices in countries which have not yet adopted a capacity mechanism. In addition, investments in coal plants are deemed acceptable where economic and where no existing legislation prevents it.

Pöyry has used four models to quantify the impact of the 2030 package, as shown in Figure 11.

Figure 1 – Interaction between different models for scenario development



Each scenario is developed using four of Pöyry's market simulation tools (detailed description of models used can be found in Annex A):

- **EU-ETS**: the impact of the increased decarbonisation ambition is investigated through Pöyry's *Carbon* model. The carbon model is a complete simulation of the EU-ETS, fully integrated with our power market analysis, and with use of banking/borrowing of certificates including the effect of uncertainty for market players.
- **Renewables**: the EU-wide renewable target is analysed using Pöyry's pan-European renewables model *Eureno*. Eureno, initially developed to analyse the burden sharing of the 2020 renewables target and extended to 2030, is a pan-European supply curve with more than 18,000 entries representing project categories and covering 18 heat and electricity technologies in 27 countries.
- **Energy efficiency**: increased energy efficiency is analysed through Pöyry's macro-economic modelling of power demand. The econometric model uses complex historical correlation between GDP growth and electricity demand, and the effect of energy efficiency, electric vehicles, electrification of heat and other new sectors of demand.
- **Power market simulation**: Pöyry's 'BID3' power market model, specialised on both the thermal and hydro power market dynamics, quantifies in detail the impact of the 2030 package. BID3 models every hour of the year, and captures the real-world flexibility and inflexibility of power markets across Europe.

Whilst all the modelling in this study has been done for the period 2015 to 2040 to avoid 'edge effects' in 2030, only results up to 2030 are presented in this report.

Main findings

Pöyry concludes that the 2030 climate package is likely to lead to a very significant transformation of the electricity system, with far reaching consequences all over Europe. Figure 2 summarises the outcome of the various scenarios.

Figure 2 – Summary of scenario outcomes

	Base	Full package	*Energy Efficiency*	*Renewables*	*Carbon*
Demand 2030 (TWh)	3420	2860	2860	3420	3420
Carbon price 2030 (€/tCO2)	27	25	*13*	*6.5*	*55*
Electricity price 2030 (€/MWh)	**80**	**52**	*61*	*48*	*90*
Do current markets work?	!	✗	✗	✗	!
Is coal capacity built?	Limited	Limited	*Yes*	*Yes*	*No*
Renewables (TWh)	1335	1647	*1323*	*2208*	*1366*
Thermal investments 2015-30 (GW)	76	21	*23*	*52*	*84*
EE/RES forced by targets (TWh)	0	873	*561*	*873*	*0*
Carbon emissions 2015-40 (GtCO2)	44	41	44	44	41
Nuclear in 2030 (GW)	762	500	*568*	*460*	*833*
Share of RES in Electricity generation	39 %	56 %	*46 %*	*63 %*	*39 %*

The difference between the Full Package Scenario and the Base Scenario is particularly striking in terms of wholesale price. This is the combined result of a lower demand by 2030 (-560TWh, more than today's German annual demand), and a higher proportion of renewables. The carbon price is virtually unchanged, as the marginal unit of abatement stays the same in both scenarios. In both scenarios, market conditions result in the development of a limited number of new coal plants.

Implementing independently the various 'decarbonisation tools' of the 2030 package leads to very different outcomes. While the Energy Efficiency and Renewables parts of the package lead to low carbon prices (€13/tCO2 to €6.5/tCO2 respectively) as carbon abatement are done outside of the EU ETS, the tightening of the cap of the EU ETS would lead to a carbon price of €55/tCO2. This difference alone does not fully account for the difference in wholesale prices between these scenarios: the Energy Efficiency and Renewables scenarios see an increase in the number of very low prices caused by intermittent generation.

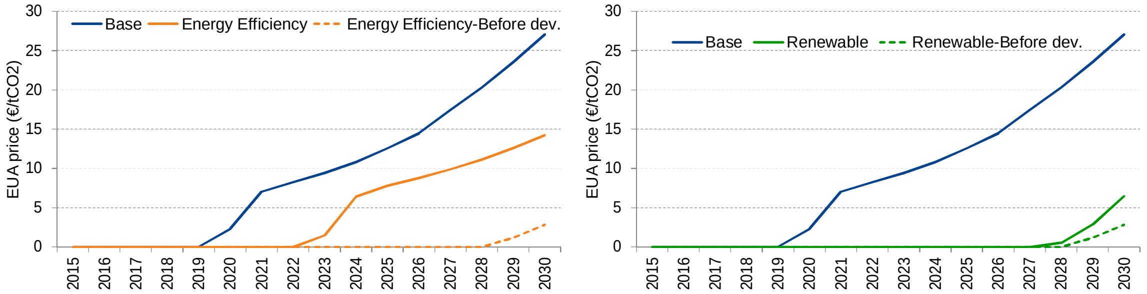
A final element is crucial in these scenarios: in the Full Package, the Energy Efficiency and the Renewables scenarios, the wholesale price alone does not support the building of new power plants, and is often not sufficient to cover annual fixed costs. If not addressed, this could lead to significant decommissioning of existing power plants and to a subsequent period of shortage: such boom-bust cycle would undoubtedly be inefficient. There are however several ways to address this situation, including the introduction of mechanisms to reward capacity or flexibility (capacity payments, energy options), or the introduction of demand-side response in a sizeable manner. In the Base and the Carbon scenarios, today's energy-only market model is still challenging, but could survive if all stakeholders accept a wholesale price formation reflecting the true value of capacity in the form of price spikes at tight periods.

Detailed findings

Energy efficiency and RES targets, if applied in isolation, cause large drops in the carbon price, compared to a business as usual scenario

The energy efficiency target in isolation leads to a 561TWh decrease in electricity demand, while the RES target in isolation leads to an increase in zero-marginal cost, zero-carbon generation of 873TWh. The implications for the carbon price are similar – A quantity of higher-carbon generation is displaced, reducing power sector emissions. Figure 3 shows the impact of this change on the carbon price both before and after scenario development.

Figure 3 – Influence of RES and EE targets on carbon prices



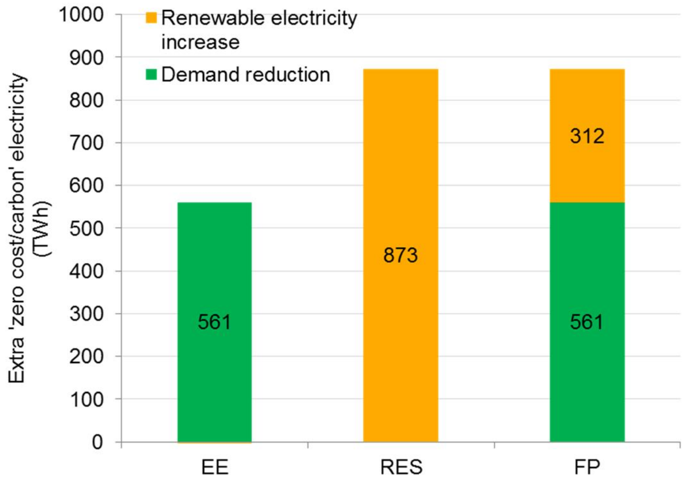
The dotted line represents the straight effect that applying the package would have if the market didn't react to increased Energy Efficiency or additional renewable generation. However, this dotted line is not internally consistent and the solid line represents the scenario once a realistic market reaction in included. The market tends to react to reduce the impact of perturbations. Lower carbon prices lead to a shift in the balance of low vs. high-carbon new investments, increasing carbon prices back towards the Base.

The EE target leads to a drop of ~€13/tCO2 in the carbon price by 2030. The RES target displaces a greater quantity of high-carbon generation, and therefore drops the carbon price by a greater ~€20/tCO2 in 2030 compared to the Base.

The Energy Efficiency target has a strong influence on the additional RES that must be built under the 2030 RES target

Both EE and RES targets effectively reduce the amount of generation required from conventional plant on the system. They can be thought of as zero-SRMC, zero-carbon 'generation' ('negawatts' is a term sometimes used to describe the energy efficiency as a kind of negative generation), funded at least partly outside the wholesale electricity market. Figure 4 shows the amount of zero-SRMC, zero-carbon generation added to EU power markets as a result of the 2030 package, compared with the Base.

Figure 4 – Changes in zero-SRMC, zero-carbon generation due to EE and RES targets



The generation added as a result of the RES target, taken on its own (i.e. applied to base case primary energy demand), is substantially higher than the 'negawatts' added as a result of the EE target. However, when EE targets and RES targets are combined in a single package, the amount of new RES generation required is substantially lower. This is because the RES target is expressed as a percentage of primary energy demand, a number that is decreased as a result of energy efficiency measures.

Energy Efficiency and RES targets delay the need for non-RES new-build substantially

Table 1 shows the timing of generic[3] new investments in a selection of countries in the Full Package scenario compared with the Base.

Table 1 – First investment post-2020 for selected countries (≥200MW)

Country	**France**	**Germany**	**Hungary**	**Poland**	**GB**
FP					
Investment Type	CCGT	–	Lignite	OCGT	CCGT and OCGT
Capacity (MW)	1000	–	1000	1000	2800
Year	2026	–	2034	2037	2020
Base					
Investment Type	CCGT	CHP gas	Lignite	OCGT	CCGT
Capacity (MW)	1200	500	500	1000	3000
Year	2023	2020	2023	2020	2020

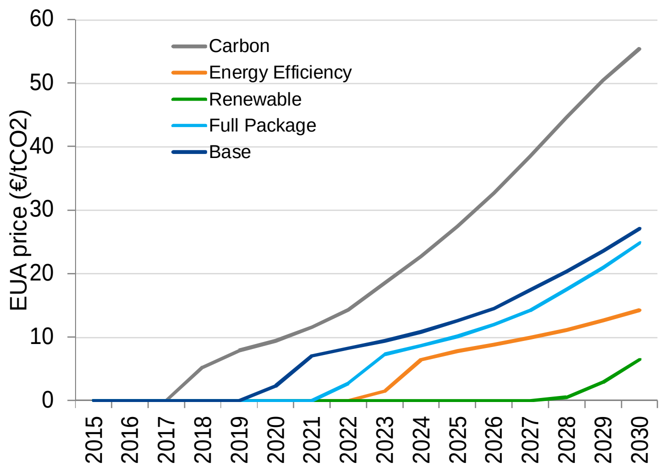
3 The term generic refers to plant build economically during the scenario development. This contrasts with named projects that are under construction and will be built regardless of economics.

In most countries the effect of the 2030 package is to delay the year in which new capacity (other than RES built as a result of the target) is delivered by the wholesale market (and, in Great Britain and France, the capacity market). In Germany the effect is most notable – no new capacity is required by 2030. This has important implications for the wholesale price (see later), which does not need to rise to new entrant levels.

When all components of the package are combined, the effect on the carbon price is small…

Figure 58 shows the carbon price in each scenario.

Figure 5 – Carbon prices in each scenario



As discussed previously, the effect of the EE or RES measures is to drop carbon prices significantly. The effect of the tighter carbon target, though, is to increase prices.

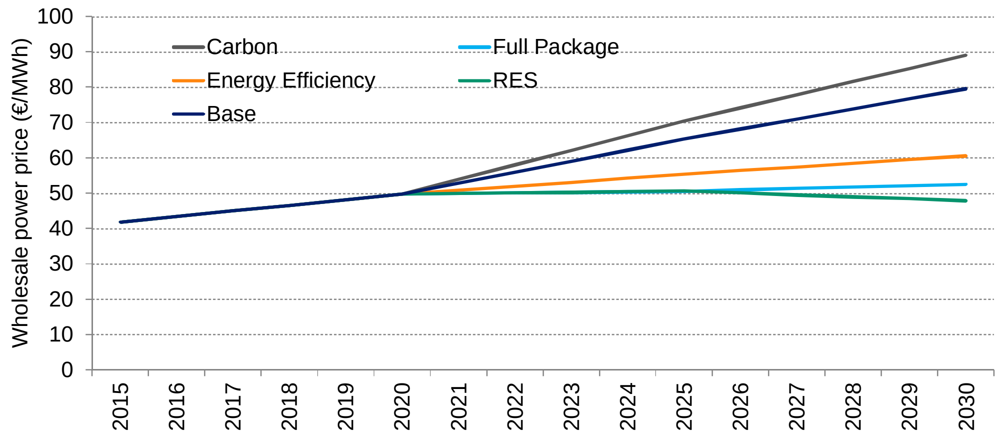
When these components are combined in a single package the effect on the carbon price is limited because:

- The total zero-SRMC, zero-carbon generation added by the full package is less than the sum of its EE and RES parts taken in isolation
- The tighter carbon cap offsets the increase in zero-SRMC, zero-carbon generation added as a result of EE and RES targets

…but the effect on wholesale prices is substantial

Figure 6 shows wholesale prices in each scenario.

Figure 6 – EU average wholesale prices in each scenario



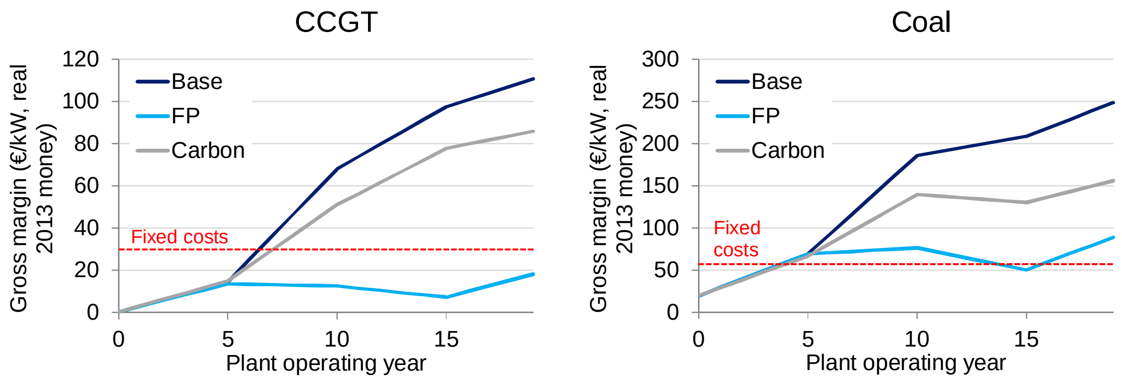
Despite similar carbon prices, wholesale prices in the Full Package are far lower than in the Base. This is due to:

- **Zero SRMC generation shifting the merit order** With the quantities of EE and RES added in the Full Package the wholesale price is increasingly set by technologies high on the merit order (i.e. with low or zero SRMC). This brings down average annual electricity prices. These low SRMC technologies are also zero-carbon, leading to a further effect – the electricity price becomes decreasingly influenced by the carbon price.
- **Low scarcity rent** Decreased peak demand from EE measures and the introduction of RES capacity mean very little new capacity is required in most countries for several decades. Overcapacity supresses wholesale prices by preventing generators from bidding above their SRMC. Put another way, in energy-only markets, where the value of capacity is reflected in the wholesale price, overcapacity reduces the value of capacity and suppresses wholesale prices.
- **Lower carbon prices** Lower carbon prices have some effect, but the change relative the Base is small.

…which means difficult conditions for conventional plant, which would likely see early retiral. This is not the case when decarbonisation is market-led.

Figure 7 shows gross margins (revenues from the power market minus variable costs i.e. fuel, carbon, variable maintenance) in the Base, Full Package and Carbon scenarios. This is for a hypothetical investment in a CCGT (left) and coal (right) plant commissioning in 2015, but the result would be similar for existing capacity or even later thermal investments.

Figure 7 – Gross margins for a hypothetical CCGT / coal plant commissioning in 2015



In the Base scenario, while the first few years of the plants' lives see low revenues they pick up above their fixed costs after some time. Typically a plant will be mothballed or decommissioned if it cannot meet its fixed costs. The mothballing or early retiral of a plant is a clear sign that the investor is making a very poor return his overall investment. It is also clearly an economically sub-optimal outcome – plant is being build and not used.

While decarbonisation through the carbon price alone does suppress conventional plant revenues and may undermine investments to some extent, it does not do so to the extent that they are forced to retire early.

Decarbonisation through carbon pricing alone leads to high carbon and power prices with nuclear as the dominant and marginal new entrant

When decarbonisation is incentivised by carbon markets alone, the carbon price rises to levels that favour the cheapest available low-carbon technology ahead of the cheapest high-carbon technology.

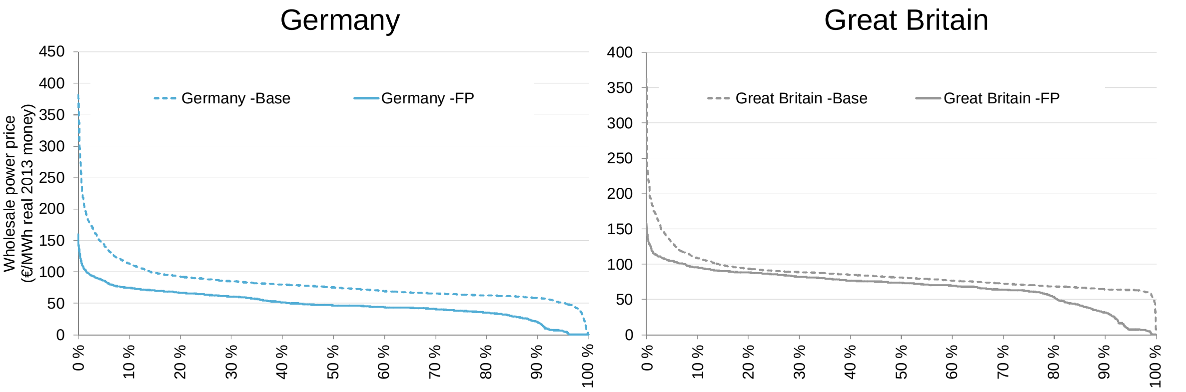
The cheapest RES technologies (onshore wind and solar in some places) are deployed first, but have limited resource potential. Once this potential is used up, the carbon price rises to the level required to bring on the next most costly low-carbon technology. At some point nuclear power becomes marginal. Given its lack of resource potential restrictions, nuclear can provide very large quantities of low-carbon generation and, in the Carbon scenario, becomes the dominant form of new build.

We note, however, that this conclusion depends on cost assumptions that are rather uncertain. Assumptions are presented in Annex B.

High RES deployment and low demand result in significant increases in curtailment and zero prices

Figure 8 shows the price duration curves for Germany and Great Britain in the Full Package scenario compared with the Base.

Figure 8 – Price duration curves for Germany and Great Britain, 2030, Full package vs. Base



The duration curves show a significant increase in the number of zero or low price periods under the Full Package. A zero price indicates that all demand can be met by RES. If this is the case it is also likely that some of the available RES is not being used i.e. it is curtailed. In reality there may be several investment responses to low or zero prices[4]:

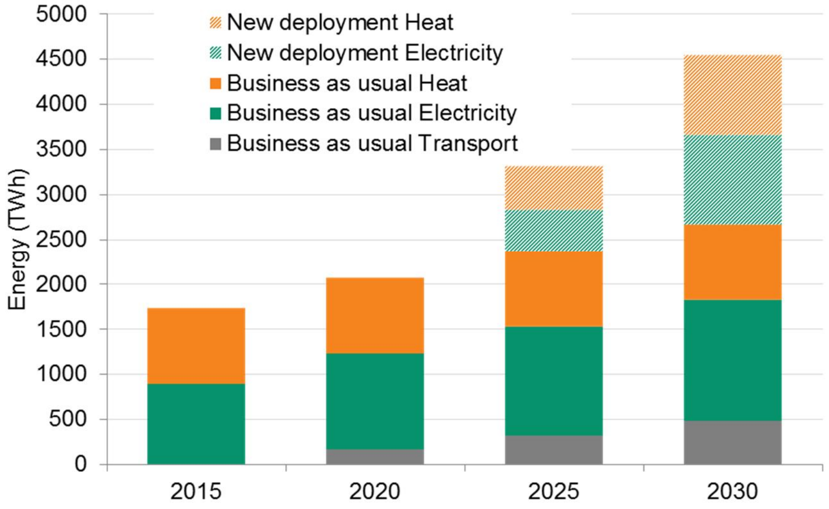
- **No response**. A certain number of zero price periods are perhaps a normal part of a system with intermittent supply. The number of zero prices has to be large enough to incentivise any investment response.
- **Increased power consumption / electrification.** Industry or consumers could respond to zero prices with investments in different forms of demand. It is flexible demand that is most likely to benefit from zero prices in specific periods – but baseload demand could be introduced in response to lower average prices.
- **Increase interconnection**. Interconnectors can sell power across borders to countries that are trading at higher electricity prices, obtaining congestion rent.
- **Reduced investment in generation.** Low power prices, particularly in period when the wind blows or the sun shines should discourage investment in technologies that generate in these periods – unless, of course, they are guaranteed revenue from out of market subsidy.

Renewable heat and electricity make a fairly even contribution to meeting the RES target. The share between these categories has important implications for the carbon price

Figure 9 shows the contribution of renewable electricity, renewable heat and renewable transport towards meeting the 2030 target in the Full Package.

[4] These responses were not modelled as part of the study

Figure 9 – Contribution of renewable electricity, heat and transport



The contribution of renewable heat (40%) and electricity (50%) towards the 2030 target is relatively even, with transport making a much smaller contribution (10%).

RES electricity generation makes up 57% of demand in 2030. This is higher than the 45% (at least) suggested by the Commission in the original proposal document, which could suggest that the Commission expects a higher contribution from renewable Heat and Transport.

Given that electricity generation is covered by the EU ETS, while heat production is not, the share of the 2030 RES target that is met by each has implications for the carbon price. The greater the share of RES-electricity, the more zero-carbon generation is added to the ETS and the more carbon prices will be supressed.

Increased renewable penetration increases the likelihood that energy markets alone will fail to deliver sufficient capacity to meet demand

If demand must be met in all periods then there will be a requirement for some plant to be built that run extremely rarely. For this capacity to be built in an energy-only market, prices would need to rise to extremely high levels in some periods to ensure that the plant that only run in these periods recover all of their capital and fixed costs. The plant also faces significant volume risk – it does not know exactly when it will be called to run. It may therefore demand even higher prices when it does run to compensate for this risk. As RES penetration increases, so does the volume risk for thermal plant, and prices in tight periods have to rise to ever higher levels to compensate.

In this study we have limited the amount that generators can bid over and above their short term marginal costs to levels that have been observed historically. In the Base this poses few problems, and the price signals in energy-only markets are potentially sufficient to bring forward the investment required to meet demand. This however assumes that all stakeholders leave market prices to rise to levels consistent with new entry, in the form of price spikes during periods of tightness.

In the Full Package scenario, however, this is not the case. Some energy-only markets fail to bring forward the required investment. For example, the Full package delays the need for new investment until 2037 in Poland. However, even when wholesale prices are allowed to rise above short run marginal costs to the extent observed historically, they are not high enough to incentivise new build. If this capacity is not forthcoming then Poland experiences loss of load. Even more importantly, power prices and margins do not support the recovery of annual fixed costs for the existing production park, which could lead to wide-spread bankruptcy and sub-optimal outcomes like for example an important cycle of plant closure followed by a need for investment in new plants.

There are a number of solutions to this issue:

1. **Allow prices to rise further**. Price volatility any higher than historic levels is deemed by many not to be an acceptable solution
2. **Allow loss of load**. Most economists would argue that this is the correct solution – a select few consumers would be more willing to shed load for a small number of periods per year, rather than pay for the capacity to cover them
3. **Develop and invest in demand side response** (flexible demand). DSR has the potential shift load from tight periods to looser periods. The cost of doing so may be lower than the cost of building new capacity, so prices would not need to rise to such high levels to incentivise investment.
4. **Remunerate capacity outside the energy-only market**. This could take the form of capacity payments or more innovative and adaptable products such as energy options. An alternative, regular revenue stream outside the energy-only market reduces the amount of money that must be recovered from the energy-only market to cover fixed and capital costs. It also reduces volume risk by providing a regular payment, regardless of whether the plant runs. The risk premium for new capacity is therefore reduced.
5. **Build strategic reserve**. This is peaking capacity that is only permitted to bid in at a fixed €/MWh value. It does not recover its costs in the energy-only market, but is ‘made whole’ by out-of-market government subsidies

In our modelling we have assumed that option 4 occurs. In Poland, the ‘missing money’ from the energy-only market for a variety of technology candidates is bid into the capacity market. CCGT has the least missing money at ~€80/kW/year and is the technology that is built. The capacity market clearing price is therefore ~€80/kW.

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1. INTRODUCTION

As part of the work on Energimeldingen The Norwegian Ministry of Oil and Energy (OED) has requested a study on the impact of future EU energy and climate policies on European power markets. This study will investigate the impact of the proposed policy framework put forward by the European Commission in January 2014: *A policy framework for climate and energy in the period 2020 to 2030*[5]. It was requested that the impact from the components of the 2030 package be assessed individually and as part of a complete package.

1.1 Background

The EU has a long history of coordinating energy policy, the first initiative[6] having been triggered by the oil crises in 1973/74. Historically the focus has been on security of energy supply, the reduction of import dependency and more efficient energy use. Other objectives have been to improve the internal energy market within the Union and to enhance competition. The first overall EU policy with a strong focus on climate and environmental issues came with the Renewables Directives in 2001 and 2003, and the introduction of the EU Emission Trading System (EU ETS) market that followed in 2005. The EU ETS market was introduced as one of the most important mechanisms for reducing greenhouse gas emissions, and still remains a central tool in EU energy and climate policy today.

"An energy policy for Europe"[7] defined a European energy strategy and laid the foundations for future EU energy policies. The strategy was published in 2007 and emphasises three important areas: sustainability, security of supply and competitiveness.

The Renewable directive[8] published in April 2009 established a European framework for the promotion of renewable energy. It included renewable targets for each member state (as a percentage of gross final consumption) up to 2020 –as part of the 20-20-20 goals. According to the directive all Member states had to submit national action plans (NREAPs) defining the targeted share of renewable energy in transport and the production of heat and electricity by 2020. The NREAPs also had to take into account energy efficiency measures and the effects on final energy consumption.

The Energy 2020 strategies consisted of what we now called the 20-20-20 goals. The energy targets for 2020 are:

- 20% reduction in GHG emissions compared to 1990 levels
- 20% renewables in EU primary energy demand
- 20% increase in energy efficiency[9]

The energy efficiency target was defined in the "Action Plan for Energy Efficiency"[10], and not explicitly part of the climate and energy package for 2020. An overall EU framework

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[5] COM(2014) 15 final

[6] Council Resolution concerning a new energy policy strategy for the Community

[7] COM(2007) 1

[8] Directive 2009/28/EC

[9] Relative to the energy consumption projection published by DG TREN (2007)

for energy efficiency was not established before 2012 with the Energy Efficiency Directive[11].

In terms of GHG emission reduction the ETS sector would have to deliver a 21% emission reduction relative to 2005 levels. Through the “Effort Sharing Decision” binding GHG emission reduction targets was established for each Member State for sectors outside the EU ETS sector. Overall the target was defined as a 10% reduction in emissions from non-ETS sectors relative to 2005 levels. The combined effort in the ETS and non-ETS sector was expected to deliver a 20% emission reduction relative to 1990.

The Energy Roadmap 2050 published in 2011 stated that GHG emissions should be reduced to 80-95% compared to 1990 levels by 2050. The roadmap seeks to set out pathways for decarbonisation within the EU after 2020, and is intended to show EU commitment to decarbonisation in order to create a safe environment for long term investments in the energy sector. However, the roadmap is primarily a description of the overall EU strategy for climate and energy towards 2050, and there is no legal commitment or binding targets for Member States up to 2050.

Continuing the efforts for EU decarbonisation the European Commission proposed an energy policy from 2020 to 2030 in early 2014. The proposal includes the following targets:

- Greenhouse gas (GHG) emission reduction of 40% relative to 1990 levels
- Renewable share of 27% in primary energy demand
- Continued efforts in energy efficiency -indicated at 25%
- Market reform of the Emission Trading System (ETS)
- New governance framework

1.2 Objectives of the study

The overall objective of this study is to assess the effect of implementing the proposed 2030 package on European power, carbon and RES markets.

The study uses detailed electricity, carbon and RES market modelling to identify and describe any challenges – and distortions – that may occur as a result of the package.

1.3 Structure of the report

The first section of the report will present the principles and methodological approach of the study. The second section will show the findings from each of the scenarios analysed, and then compare them together.

1.4 Conventions

Unless otherwise stated, all values are in real 2013 money.

[10] COM(2006) 545

[11] DIRECTIVE 2012/27/EU

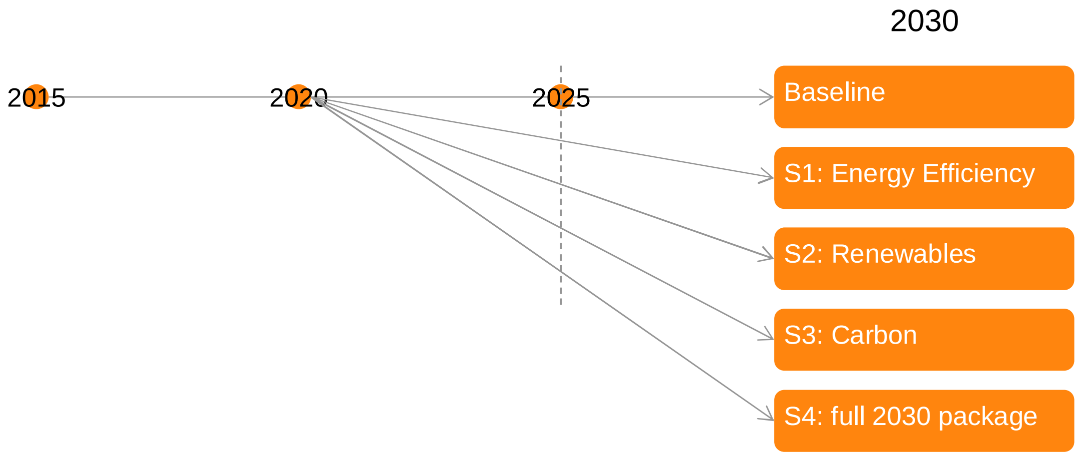
2. APPROACH

This section describes the methodology and assumptions used to assess the impact of the 2030 package. The scenario-based approach is discussed first, followed by a description of the methodology used to develop each scenario. Finally the inputs used in each scenario are presented.

2.1 Scenario-based approach

A scenario-based approach is used to test the different components of the package individually, and then together as a “Full Package”. The scenarios developed are listed below and illustrated in Figure 10.

Figure 10 – Scenario-based approach



Scenarios investigated include:

- **Baseline** (Base) scenario with a “business as usual” assumption with only existing policy framework from 2020 to 2030
- **Energy Efficiency** (EE) scenario with 25% increase in energy efficiency relative to 2007 projections by DG TREN
- **Renewables** (RES) scenario with 27% renewables in primary energy demand
- **Carbon scenario** ensuring a 43% reduction in GHG emissions in the ETS sector compared with 2005 levels
- **Full Package** (FP) scenario combining all the elements of the 2030 package

All scenarios are developed and modelled up to year 2040, but results are only presented up to year 2030. The reason for this approach is the intertemporal nature of carbon markets. Permits can be banked between years, so the value of the permit in 2030 depends on market participants’ views of supply and demand in the years that follow[12].

[12] See Annex A.2 for detailed description.

As indicated in Figure 10, the scenarios are all identical up to 2020. After this point, investment decisions vary between scenarios in response to the different policies being applied. The one exception to these rules is the carbon price, which is influenced even before 2020 by investment decisions made later in the scenario.

2.2 Developing consistent scenarios

This section describes the methodology of scenario development and the interaction between different models used in the study. Interaction between different models is illustrated in Figure 11.

Figure 11 – Interaction between different models for scenario development

Each scenario is developed using four of Pöyry's market simulation tools (detailed description of models used can be found in Annex A):

- **EU-ETS**: the impact of the increased decarbonisation ambition is investigated through Pöyry's *Carbon* model. The carbon model is a complete simulation of the EU-ETS, fully integrated with our power market analysis, and with use of banking/borrowing of certificates including the effect of uncertainty for market players.
- **Renewables**: the EU-wide renewable target is analysed using Pöyry's pan-European renewables model *Eureno*. Eureno, initially developed to analyse the burden sharing of the 2020 renewables target and extended to 2030, is a pan-European supply curve with more than 18,000 entries representing project categories and covering 18 heat and electricity technologies in 27 countries.
- **Energy efficiency**: increased energy efficiency is analysed through Pöyry's macro-economic modelling of power demand. The econometric model uses complex historical correlation between GDP growth and electricity demand, and the effect of energy efficiency, electric vehicles, electrification of heat and other new sectors of demand.
- **Power market simulation**: Pöyry's 'BID3' power market model, specialised on both the thermal and hydro power market dynamics, quantifies in detail the impact of the 2030 package. BID3 models every hour of the year, and captures the real-world flexibility and inflexibility of power markets across Europe.

The study covers all EU member states, and it is assumed that countries outside the EU, including Norway, do not implement the 2030 package.

Figure 11 illustrates the interaction between the models as the scenario is developed. Since the outputs of some models influence the outputs of others, it is necessary to run the models iteratively until the results given by all models are consistent.

The results of the demand model (or the demand assumptions taken) are not assumed to be influenced by the results of the other three models. The first step in the scenario development is therefore to determine primary energy demand (which forms the basis of the demand for RES deployment in Eureno) and electricity demand (which is fed into BID).

Renewable investments can either be (a) driven by European and national policies (i.e. ‘forced’ on, regardless of their economics); or (b) based on economic profitability. However, it is assumed that, for all scenarios, renewable capacity entering the market will not be lower than what is described in the Base scenario. Technology cost assumptions and hurdle rates for renewable capacity are given in detail in Annex B.

There are various mechanisms through which renewable generation can be “forced” into the system – all of which require some form of out-of-market support. In the Base case, NREAPs are followed (generally being met later than the 2020 goal). The 2030 package has not, as yet, been prescriptive about technology choice and location. Instead, it discusses the importance of a more market driven deployment across Europe. In modelling the 2030 target, therefore, we use our renewables model Eureno, which takes an overall RES target and determines optimal deployment. Renewable potential and the cost for each technology and for each Member State are imputed into Eureno. This gives a supply curve of renewables for heat and electricity for the EU as a whole. The difference between the Base scenario[13] and the defined renewable build out target is the demand curve in Eureno. The output is given by the intersection between supply and demand, and gives the split between electricity and heat, renewable technology and the geographical distribution of the renewables build out. The total renewable electricity build out is then fed into BID for each country and technology.

Once electricity demand and renewables build out have been determined by the demand model and Eureno, we can begin to assess the response of electricity and carbon markets.

In BID3, the principles used to determine the market response take the point of view of a market investor. In the real world the market and investors respond to changing market conditions, and it is unlikely that the same investment decisions will be made in e.g. scenarios with high and low growth in energy demand. This study takes the investor point of view, and all capacity build-out in the period 2020 to 2030 is based on economic profitability. This means that new capacity and power plants will not enter the market unless it receives the required rate of return on investment. Investment decisions are therefore determined based on fuel prices, CO2 prices, wholesale electricity prices and plant running patterns. In situations where the market is not able to initiate required investments to ensure security of supply investments are based on “least missing money”. This is an indication that the energy-only market is not able to deliver required investments, and that generators have to receive a revenue stream outside the wholesale power market. It will be clearly stated when investments are based on “missing money” rather than their internal rate of return.

Generation profiles for renewable energy (wind, solar radiation etc.) and electricity demand profiles (e.g. hourly demand patterns) are based on historical weather years. In this study we have applied the historical weather year 2006, which is considered to be an “average” weather year in Continental Europe.

The BID3 power market model is the central tool in this analysis; however, developing consistent scenarios requires an iteration process with the Carbon model. Changes in electricity market investments have an impact on emissions and the carbon price. In a

[13] Here also called «Business as Usual» assuming no new policy targets for 2030

consistent scenario there is an equilibrium between investment decisions and carbon prices. High carbon prices typically encourage investment in lower carbon technologies, which in turn reduce carbon emissions and the carbon price. An iteration process is therefore important for finding the right balance between market responses to carbon prices, and ensuring that the modelled carbon price reflects the actual generation mix.

2.3 Scenario inputs

In this section the common and differentiated inputs of the scenarios are presented.

2.3.1 Important assumptions

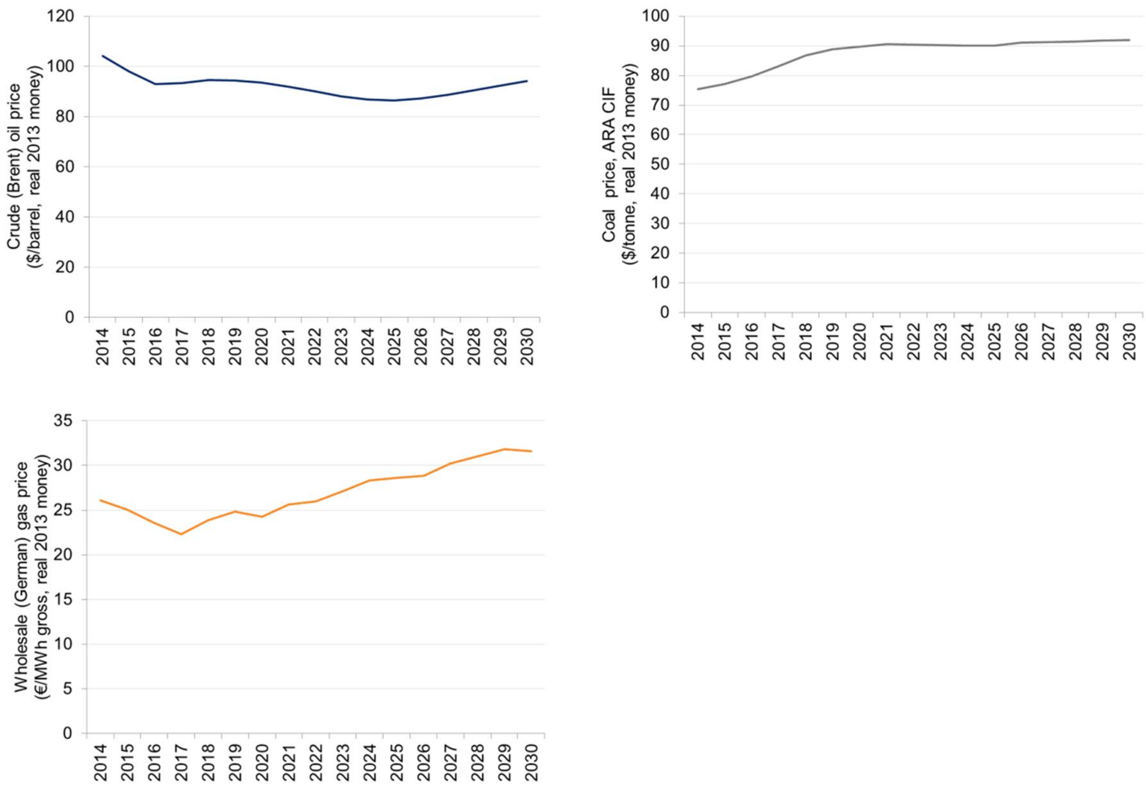
In this study, the Norwegian Ministry of Oil and Energy guided some crucial assumptions, in particular that the recovery of fixed and investment costs could be realised through the peakiness of wholesale prices in countries which have not yet adopted a capacity mechanism. In addition, investments in coal plants are deemed acceptable where economic and where no existing legislation prevents it.

2.3.2 Common features of all scenarios

2.3.2.1 Fuel prices

Fuel prices, with the exception of CO_2, are kept constant for all scenarios. Figure 12 illustrates fuel prices for crude oil, coal and natural gas for the whole projection period.

Figure 12 – Fuel prices projections for crude oil ($/barrel), coal ($/tonne) and natural gas (€/MWh)

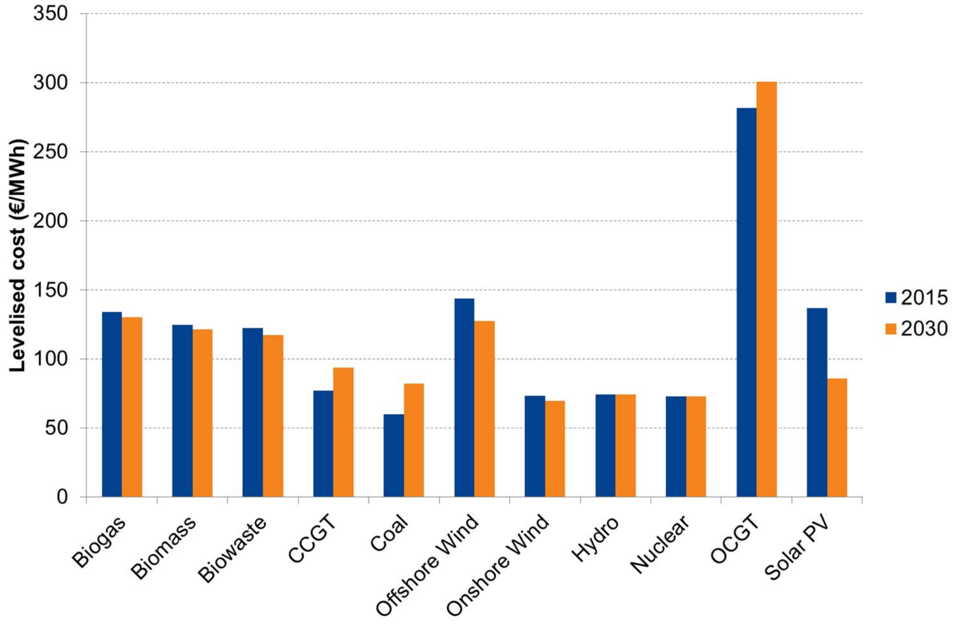


Crude oil prices are expected to drop towards year 2025 and then pick up towards 2030. The average price over the projected period is €68.8/barrel ($92.2/barrel). Coal prices (ARA)[14] increase over the whole projection period and average prices from 2014-2030 is expected at €65/tonne ($88/tonne). Current coal prices are influenced by continued abundant supply, and a stable market that holds strong reserves. It is expected that future coal prices will trend towards the long run marginal cost (LRMC) of coal production and shipping, and the price reaches €67/tonne ($90/tonne) in 2020 and remains close to this level until year 2030.

Gas price projections are weighted between oil-indexed and long run marginal components, and reflect market prices for marginal suppliers in the market. Gas prices are increase over the projected period and reach €31.6/MWh in 2030.Technology costs

Capital expenditure (capex) and required rates of return vary between different EU member states (and different technologies). Figure 13 shows the long run marginal cost (levelised cost) for selected technologies in GB in 2020 and 2030.

Figure 13 – Capital cost for selected technologies in Great Britain



For mature technologies (e.g. onshore wind and small hydro) the potential cost decrease is small. For less mature technologies, such as offshore wind and solar PV, a continued drop in prices is expected over the projection period. Levelised cost for solar PV is expected to drop 37% between 2020 and 2030, and offshore wind is expected to drop 12% within the same timeframe. The capex differ among the Member States and is indexed with labour costs (for civil engineering) – a country with high labour cost will have a higher capex than a country with lower labour cost. The hurdle rates are mainly determined by the technological maturity. Also countries with low/high credit rating have higher/lower required return on investment.

[14] The Amsterdam Rotterdam Antwerp hub; used as a European reference price

The levelised cost of CCGT and Coal plants increases over the timeframe, under the combined effect of fuel and carbon price movements.

2.3.2.2 Decommissioning of plants

Plant investments that are made up to year 2020 are kept constant for all scenarios, and investment decisions post-2020 are made in accordance with the scenario development principles described in Section 2.1. In the Base scenario plants that do not meet their fixed costs are decommissioned. However, the existing park is kept constant in other scenarios, and power plants are not retired or decommissioned before the end of their economic lifetime. As a result, power plants commissioned before 2020 that are not profitable (in a specific scenario) can remain in the system until the end of their economic lifetime. This is a conscious decision which is a result of the approach: if a very sizeable share of existing plants needs to decommission due to the impossibility of paying for their fixed costs, this would immediately lead to a situation requiring new investments which in turn would be unlikely to recover their fixed costs. This decommissioning-investment cycle would not be sustainable or efficient and therefore other solutions would be likely to be put in place. In this study, we have assumed that this could take the form of a capacity payment mechanism which would at least allow most existing plants to remain on-line and if necessary spark new investments.

2.3.2.3 Capacity markets

The overall market design across the EU is the “energy-only” market, with the exception of GB, Ireland, France, Spain and Greece where capacity markets[15] are applied. Principles for investment decisions differ between the two market designs and a more detailed description of this methodology can be found in Section 2.1.

2.3.2.4 Scarcity rent

In an energy-only market the wholesale power price should reflect the value of capacity. In tight periods, the value of capacity goes up. Generators know there is little competition on the system and can bid into the wholesale market above their short run marginal cost (SRMC). This is not market abuse, but is, in fact, necessary for those plants that run infrequently to recover their capital and fixed costs. This added value above the SRMC is called scarcity rent and is applied to energy-only markets in this study. In looser periods scarcity rent will be small as generators compete with competitors to run and therefore bid close to their SRMC. Markets with overcapacity tend to have very few tight periods and so, on average, scarcity rent in the wholesale price is low. This leads to the absence of further investment in capacity and may even result in some existing plant closures.

2.3.2.5 Technology restrictions e.g. nuclear, coal, etc.

Some countries have applied regulation towards the build out of specific technologies. This is particularly the case for coal and nuclear plants across the EU. It is assumed that current legislation will prevail up to 2030, and that no new policy restrictions will be introduced within the same timeframe 2015 to 2030. The following build out restrictions apply:

[15] Here: the term “capacity market” does not include the strategic reserve model; a mechanism applied to several other EU countries (e.g. Sweden, Finland and Poland).

Table 2 – Restrictions for build out of nuclear and coal/lignite

Country	Nuclear	Comment	Coal/Lignite
Austria	✗		✓
Belgium	✗	Phase out of existing reactors	✓
France	✗	No increase in build out -target 50% nuclear in energy mix by 2025	✓
Germany	✗		✓
Italy	✗		✓
Spain	✗		✓
UK	✓		✗

2.3.3 Base

The Base scenario describes the most likely evolution of the European power market based on existing European and national policies and current legal frameworks. This scenario takes into account the 2020 package and the ambitions for European decarbonisation

2.3.3.1 RES deployment

RES deployment is based on individual countries' NREAPs, which provide technology specific targets. Most member states are assumed to deliver their national target after 2020 as illustrated in Table 3.

Table 3 – Compliance with the national 2020 renewable targets

<table>
<tr><th></th><th>DEU</th><th>FRA</th><th>GBR</th><th>NET</th><th>SWI</th><th>BEL</th><th>POL</th><th>AUS</th><th>NOR</th><th>SWE</th><th>DEN</th><th>FIN</th><th>EST</th><th>LAT</th><th>LIT</th></tr>
<tr><td>2012</td><td>Hist</td><td colspan="7">Hist</td><td>Hist</td><td>Hist</td><td>Hist</td><td>Hist</td><td>Hist</td><td>Hist</td><td>Hist</td></tr>
<tr><td>2020</td><td>2020</td><td colspan="7">Part</td><td colspan="2">GC market targets met</td><td>Part*</td><td>2020</td><td>2020</td><td>Part</td><td>2020</td></tr>
<tr><td>2025</td><td>2020+ 4%</td><td colspan="7">Part</td><td colspan="2" rowspan="2">Flat in capacity terms</td><td>Part</td><td>2025</td><td>2020</td><td>2020</td><td>2020</td></tr>
<tr><td>2030</td><td>2020+ 8%</td><td colspan="7">2020</td><td>Part</td><td>+10% capa.</td><td>2020</td><td>2020</td><td>2020</td></tr>
</table>

It is worth noting that, for most countries, a total energy target of 20% was translated into significantly higher share of electricity in the NREAP. The share of electricity from renewables in the base case by 2030 is therefore significantly higher than 20%. Note also that Germany was assumed to continue adding RES even after its target is met in 2020.

2.3.3.2 Demand

The demand used in the base scenario is Pöyry's Central assumption. It is derived using a combination of short term forecasts from TSOs, in-house econometric models and country expert opinion. It assumes a small amount of energy efficiency, based on existing policies.

Figure 14 in section 2.3.4 shows demand projections for the EU in the base.

2.3.3.3 Carbon

Power sector emissions are constrained by the EU ETS. The cap decreases at 1.74% per year to 2020, consistent with the 2020 package. Beyond 2020 this linear reduction factor is maintained. A market stability reserve is also assumed. See Section A.2 for more detail on this.

2.3.4 Energy efficiency

The Energy Efficiency scenario contains all the same inputs and development principles as the Base, other than a change in electricity demand.

The Energy Efficiency (EE) Scenario investigates the impact of 25% reduction in primary energy demand relative to the demand projections published by DG TREN in 2007. In the communication on the 2030 package there was no mention of a final energy efficiency target for 2030, but an indication that a 25% reduction by 2030 was necessary to achieve 40% emission reduction by 2030. There was no announcement of a new reference point for energy efficiency in the communication, so the original reference point from the Energy Efficiency Directive (EED)[16] is applied in this study. In July 2014, before the publishing of this study, the Commission announced what it calls *an ambitious target* of 30% energy efficiency by 2030[17] against projections published by DG TREN in 2007.

In 2013 DG TREN published a new set of projections for primary energy demand up to 2050. In the EE scenario the 2013 DG TREN projections have been applied to the heating and transport sectors, and electricity demand projections come from Pöyry's long term demand model for electricity in Europe (see Annex A.4 for model description). Post-2030 we assume the same growth in primary energy demand as in the DG TREN 2007 projections.

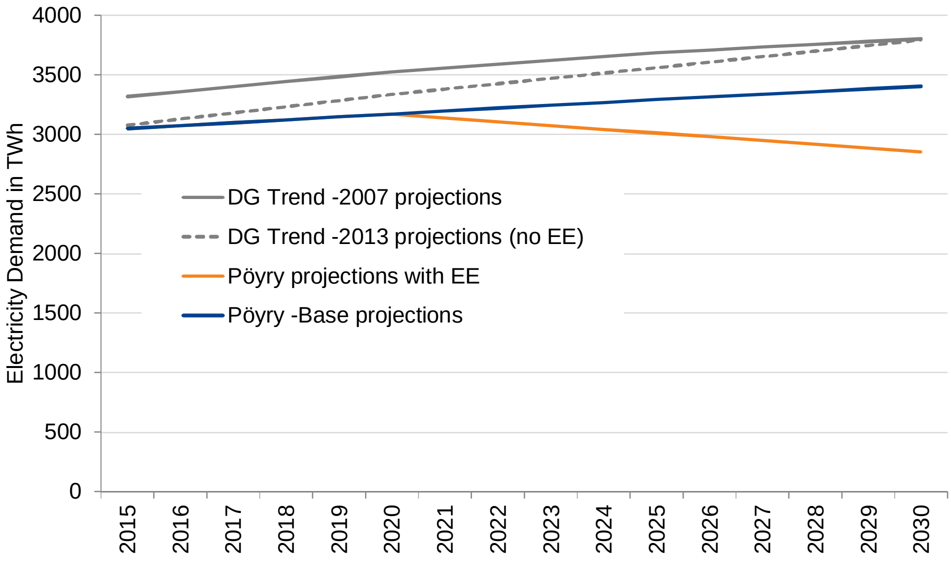
This study does not investigate if energy efficiency is more likely (or cost efficient) to come from the heating or electricity sector. Also the study does not evaluate the burden sharing of energy efficiency between member countries. We have therefore applied a 25% reduction in energy demand across all primary energy sectors, and across all EU member states relative to the DG TREN 2007 projections.

Figure 14 shows the difference in electricity demand projections for all EU member states.

[16] Directive 2012/27/EU

[17] July 2014, COM(2014) 520 final

Figure 14 – Total EU Electricity Demand projections (TWh)



In this scenario the Pöyry electricity demand projection with energy efficiency is applied. It should be noted that the Pöyry Base projection also includes some energy efficiency – accounting for some of the difference between the Pöyry and DG TREN projections.

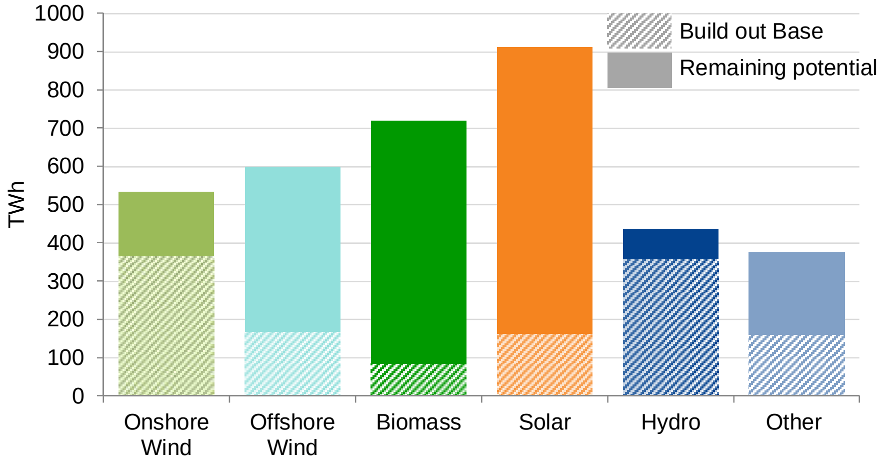
2.3.5 RES

The RES scenario contains the same development principles as the Base, but more renewable capacity is "forced" into the system from 2020 to 2030 to meet the renewable target.

In the RES scenario the overall target of 27% renewables in primary energy demand by 2030 is reached on an overall European level. Deployment of renewable technologies and the distribution of new build between member counties are based on a least cost principle across Europe. The target is reached by building 1877 TWh of new renewable energy, where 53% comes from the electricity sector, and 47% from the heat sector. The burden sharing between different sectors is determined by the same principle of least cost deployment across Europe and different demand sectors.

The Eureno model (see Appendix A.3 for detailed model description) is used to determine the geographic and technological distribution of renewables. Cost assumptions, such as capex, opex and hurdle rates, are input for each technology in each country. Adding technology and potential restrictions for each country gives a renewable supply curve for the EU as a whole. The deployment of renewables is then given by the intersection of the renewable supply curve and the required new build. Figure 15 shows the renewable electricity build out and the potential in the EU up to 2030. The build out up to 2030 is from the Base scenario.

Figure 15 – EU renewable build out and potential up to 2030 (TWh)



Renewables added in the RES scenario comes on top of the renewable growth in the Base scenario. In this scenario it is assumed that renewables receive subsidies on top of the wholesale market price. Using the approach of a European supply curve and the least cost deployment of renewables this would (in theory) be equivalent to a European green certificate market.

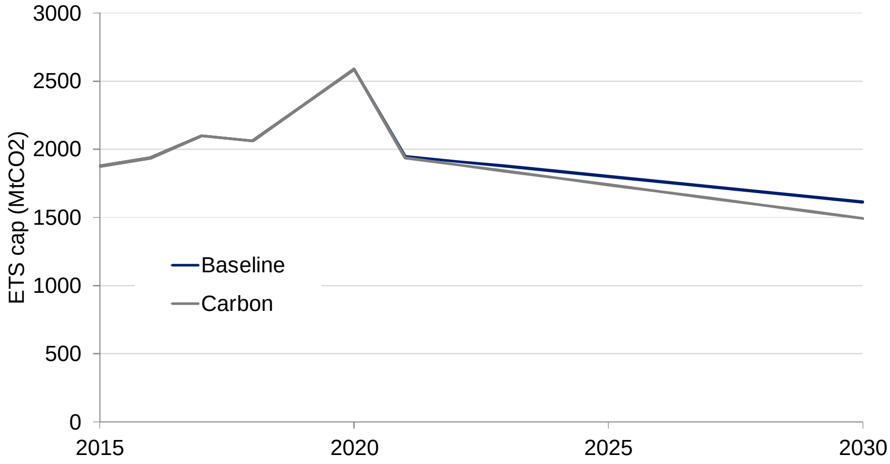
2.3.6 Carbon

The Carbon scenario contains all the same inputs and development principles as the Base, other than a tighter emission cap post-2020.

The Carbon scenario investigates the effect of tightening the cap to 43% in the ETS sector compared to 2005 emission levels. This implies that the reduction in the carbon emissions cap will have to be increased from an annual factor of 1.74% to 2.2% post-2020. Suggested changes to the ETS market also includes a Market Stability Reserve (MSR) that will be introduced in phase 4 trading in 2021. The MSR is designed to make the ETS market less sensitive to market shocks and to ensure market stability and sufficient price signals for low-carbon investments. This market design also seeks to limit the impact of international credits (CDM) and complementary emission reduction policies e.g. renewable energy subsidies and energy efficiency. A more detailed description of the Market Stability Reserve can be found in Annex A. The Carbon Scenario takes into account back-loading of 900 million allowances in phase 3 (2013-2020) in the ETS system.

The ETS cap for our Base –and Carbon scenario is illustrated in Figure 16.

Figure 16 – ETS cap in Base –and Carbon Scenario (Mt CO2)



The difference in the abatement curve looks small, but has a significant impact on the carbon price which will be shown later in this study. The accumulated difference in emissions from the ETS sector between the Base and Carbon Scenario is equivalent to about 660 Mt CO2 in the period 2020-30.

Abatement and emission reduction in the Carbon Scenario is driven by the carbon price alone, by making carbon intensive generation less profitable relative to low emission generation. This means that renewable energy and other capacities do not receive any support or subsidies outside the wholesale market in this scenario.

In this study the modelling has been performed up to 2040 in order to avoid 'edge effects' of the carbon market in 2030. While results are not presented post 2030, they sometimes have an impact on 2030 results due to the banking and borrowing nature of the system: abatement in 2030 can in theory come from a coal plant built in 2035 through borrowing.

2.3.7 Full Package

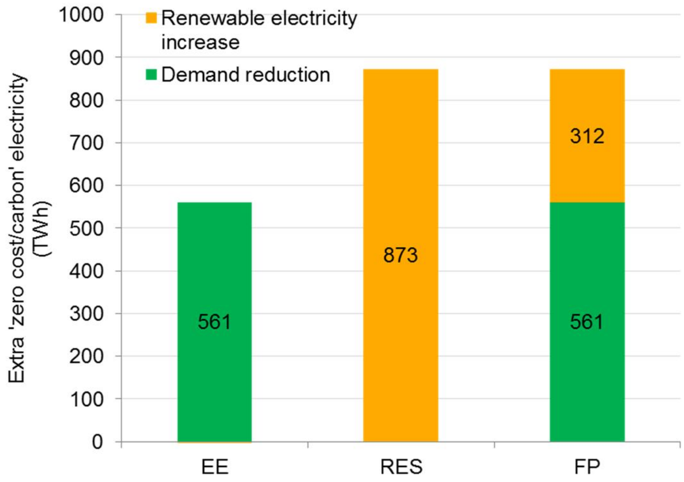
The Full Package (FP) scenario combines all targets in the 2030 package;

- Reduction in primary energy demand of 25%
- Renewable generation equivalent to 27% of primary energy demand
- Tighter ETS carbon cap of 43% compared to 2005 levels

This scenario applies the same TWh amount of energy efficiency as in our Energy Efficiency scenario. However as primary energy demand is reduced the total renewable build-out in electricity (and heat) is reduced accordingly, as less renewables are needed to supply 27% of primary energy demand.

In the electricity sector the FP scenario results in zero cost, zero carbon emission electricity of 873TWh, similar to our RES scenario. Figure 17 shows the added zero carbon generation and reduced demand across the different scenarios relative to the baseline.

Figure 17 – Extra zero cost/carbon electricity in EE, RES and FP



The figure suggests that the EE, RES and FP scenario will have a downward impact on the carbon price, as a significant amount of zero carbon electricity is forced into the system and due to emission reductions in the form of energy efficiency (reduced demand). However in the FP scenario we introduce a tighter carbon cap which has an upward effect on the carbon prices.

3. FINDINGS

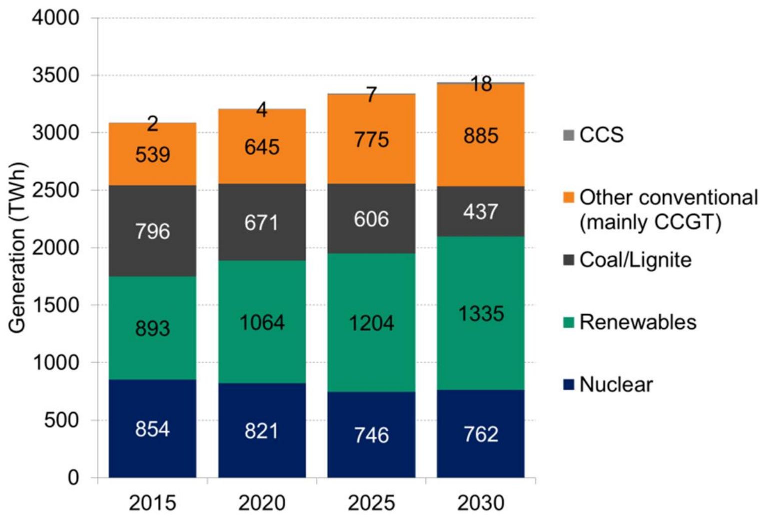
This section describes the results for all scenarios. The findings presented are the outcome after the development of consistent scenarios. Carbon prices, however, are also presented before scenario development. This is included in order to illustrate the impact of different investment decisions on the carbon price.

3.1 Base scenario

The Base case scenario describes the most likely evolution of the European power market based on existing European and national policies and legislation. The scenario therefore assumes no new climate and energy package from 2020 to 2030.

Figure 18 shows the evolution of the generation mix from 2015 to 2030 in the Base scenario.

Figure 18 – EU generation mix Base scenario (TWh)



It is assumed that the share of RES in electricity generation will increase post-2020, reaching 39% of electricity generation and demand by 2030, when we assume most countries meet their NREAPs. This figure is higher than the target for RES as a share of *total* energy consumption (20%) because:

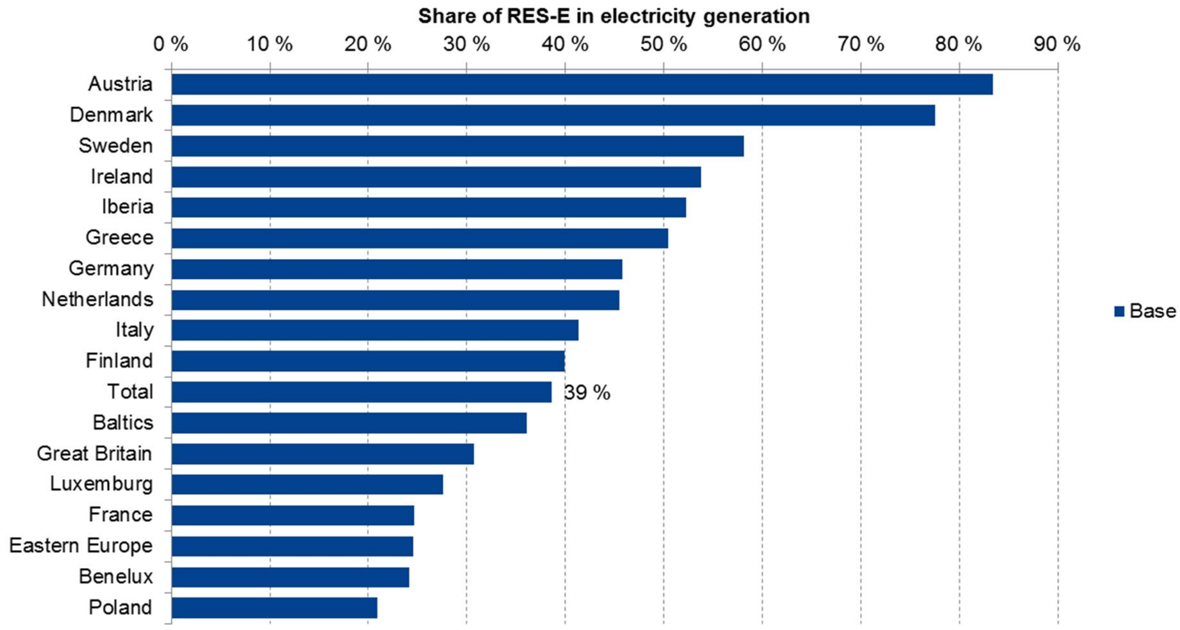
- NREAPs planned for a larger share of RES from electricity than other sectors
- We assume that Germany meets its NREAP in 2020 and continues deploying RES with out of market support, reaching the NREAP + 8% in 2030
- A small amount of RES is actually economic purely based on wholesale prices, and is therefore built on top of the NREAP

The demand weighted average of the NREAP electricity targets is ~34%. Therefore the amount of RES built in the Base on top of the NREAPs is ~5% of demand, or ~170TWh.

Growth in electricity demand is to a large extent met by the growth in renewable generation (and capacity). In the period 2020 to 2030 electricity demand increases by 234 TWh and renewable generation increases by 271 TWh. Generation from coal and lignite is reduced from 18% in 2020 to 13% in 2030, whilst the share of other conventional power plants such as CCGTs and OCGTs increases from 20% in 2020 to 23% in 2030.

Figure 19 shows the renewable share in electricity generation for all member states (excluding Luxembourg, Cyprus and Malta) in 2030.

Figure 19 – Renewable share by country, EU members 2030

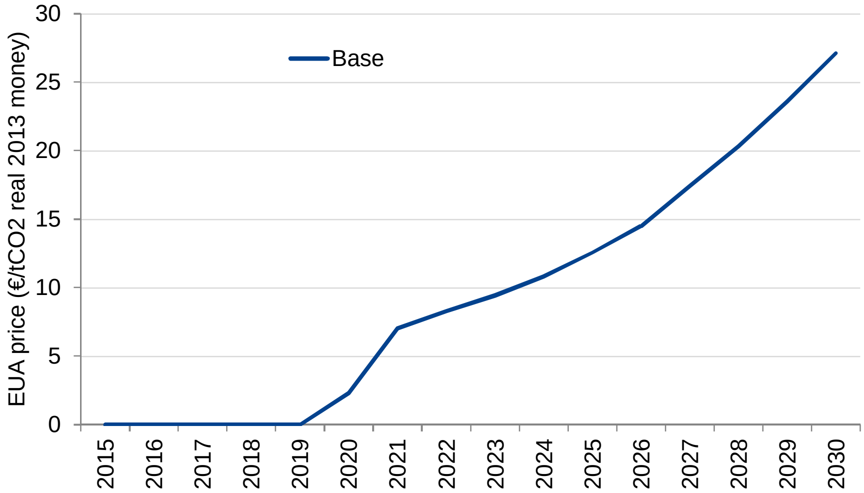


The EU percentage average is 39% in year 2030, but the contribution to renewable investments and generation differs between EU member states. Hydro dominated Austria and Sweden have renewable shares well above the EU average, joined by Denmark and its high wind generation and Portugal with a high share of hydro and wind in her electricity generation. The countries with the lower renewable share are found among the more recent EU members in Eastern Europe (e.g. Hungary, Czech Republic, Slovakia, Poland etc.). Countries such as Hungary has a high share of nuclear and zero emission generation by 2030, whereas the other low RES countries maintain a high level of coal and lignite in their power mix. The biggest contributor in absolute renewable generation is Germany with 198 TWh[18] in 2030.

Figure 20 shows the evolution of the carbon price in the Base scenario.

[18] Equivalent to 38% of Germany's total electricity production in 2030

Figure 20 – Carbon price Base scenario (€/tCO2)



The carbon price, based on fundamentals here, is zero up to 2020. This is mainly due to the large current surplus of about 2 billion allowances[19] in the ETS market that has accrued mainly as a result of the economic recession. The surplus grows towards the end of the third ETS trading period (2013-2020), reaching a total of 2.6 billion in 2020.

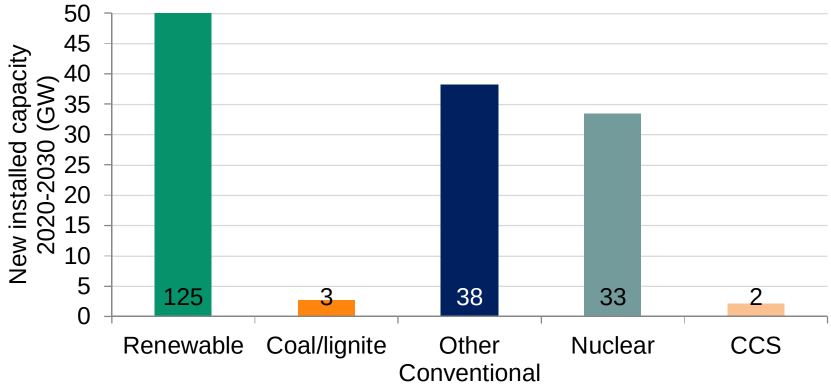
Our modelling assumes an idealised market stability reserve where surplus permits are banked in the short term for use in the long term, reducing costs overall (see Annex A.2 for details). The time horizon for the banking decision is 20 years. A price of zero in, say, 2015, indicates that there is no requirement for abatement over the period 2015-2035.

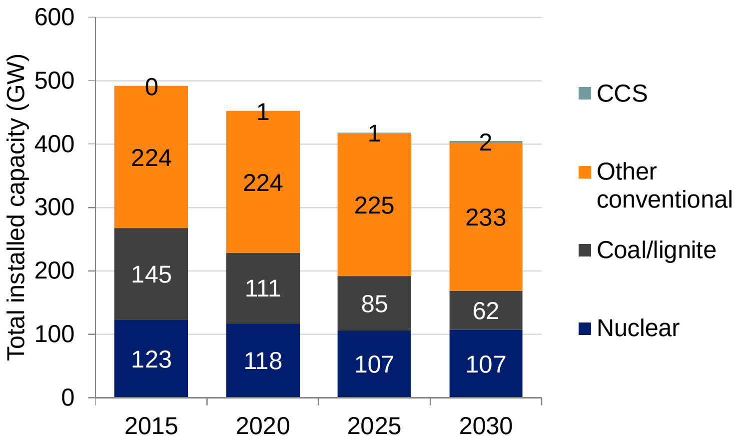
With the ETS cap tightening at a rate of 1.74% per year from 2021, abatement is not needed in the ETS sector until 2020. The carbon price rises to €27.1/tCO2 by 2030.

Figure 21 shows new installed capacity in the Base scenario from 2020 to 2030 (axis as cut at 50GW), and total installed thermal capacity from 2015 to 2030. This includes new investments and repowering.

[19] COM(2014) 20/2

Figure 21 – Thermal installed capacity and investments (GW)



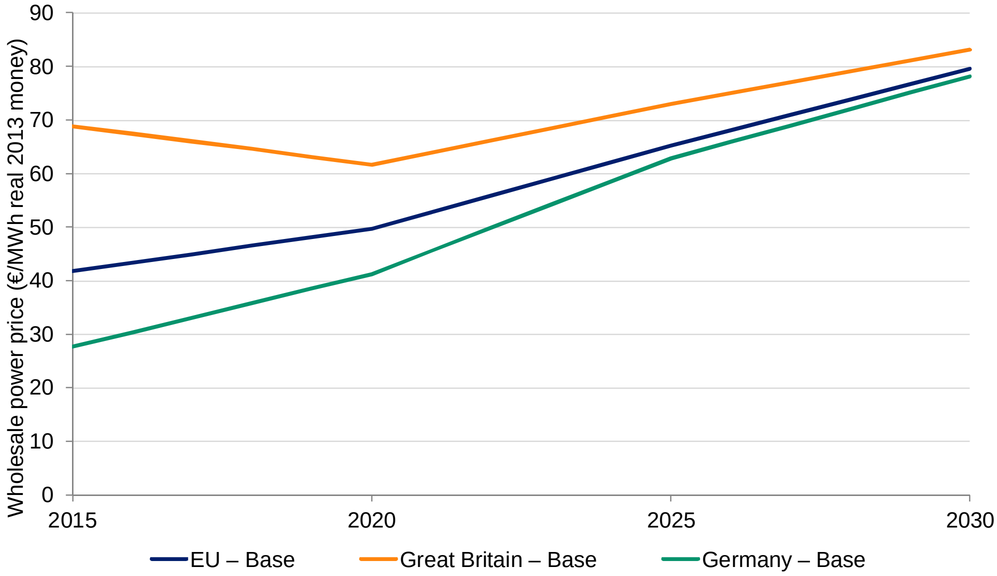


Note that the axis of the top graph is cut for a better readability

About 76GW of new thermal capacity enters the system in the period 2020-2030. Some of these investments are replacing existing capacity that is being phased out from the system within the same time period. As the carbon price starts to pick up from zero after 2020 the relative profitability of carbon intensive generation is reduced, and old carbon-intensive generation (e.g. coal plants) is slowly replaced by less carbon-intensive generation (e.g. CCGTs) and renewables. With the CO2 prices seen in the Base case the dominant new entry technology is CCGT, although a small number of new coal and lignite investments are profitable in some countries (e.g. in Germany, Poland and Hungary). Nuclear capacity investments equal 33GW, and about 53% of this capacity comes from Eastern European countries.

Figure 22 shows the demand weighted wholesale prices for the EU, GB and Germany.

Figure 22 – EU average electricity wholesale prices (€/MWh)



Demand weighted wholesale power prices increase in the EU up to 2030. The price increase is driven by:

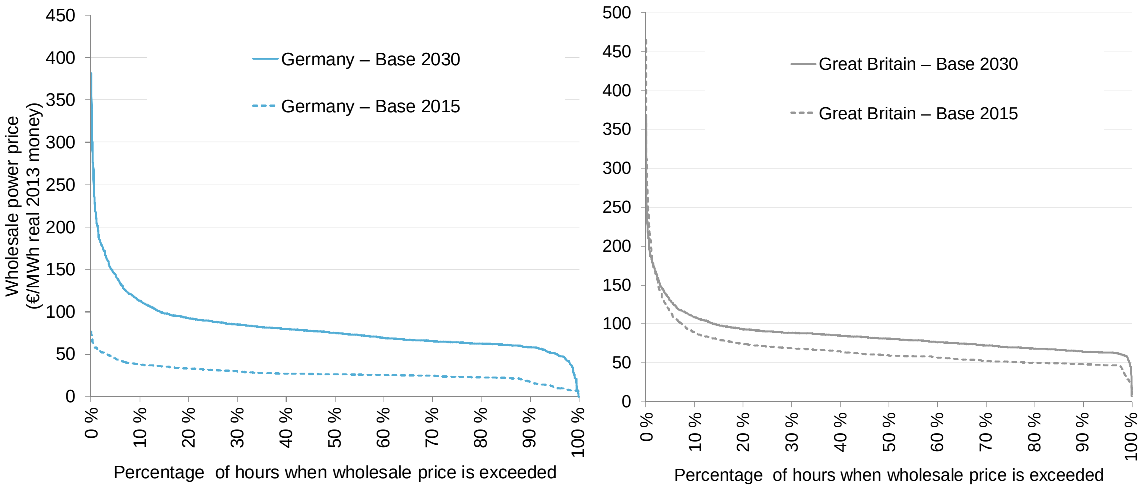
- **A switch of marginal technology** from coal-fired power plants to gas-fired power plants. While there is always a range of price setting plants during the year, the clear tendency is for CCGTs to set the price increasingly often over time due to the decommissioning of existing capacity like coal, lignite and nuclear.
- **Fuel prices**; the wholesale gas prices in Germany which is expected to increase over the whole projection period, driving up the cost for marginal plants such as CCGTs. The price of crude oil and coal is expected to remain more or less flat from 2020 to 2030.
- **Carbon prices**; with the tightening of the emission cap post-2020 carbon prices are expected to increase towards 2030. An increase in the carbon price increases the cost of running carbon emitting thermal plants.
- **A transition from a situation of overcapacity (no new build required) to one of capacity shortage (new build required)**; as demand increases (or remains similar) and existing capacity retires. Prices begin the period with very little 'scarcity rent', with this component eventually rising to cover the capital costs of the marginal new entrant.

In GB the wholesale power price is above the EU average for the projection period. This is due to carbon price floor which supports the wholesale price, and also legislation restricting new build of relatively cheap coal. New capacity therefore comes from more expensive technologies such as nuclear and CCGTs. However, the GB has a capacity market meaning that the wholesale power price is not required to fully cover the cost of new entrants to ensure capacity adequacy.

In Germany the wholesale power price is below the EU average, but slowly converges towards the EU average from 2020 to 2030. Before 2030 Germany is in a situation of overcapacity, and this is reflected in lower wholesale prices.

Figure 23 shows the price duration curves for Germany and GB in 2015 and 2030.

Figure 23 – Duration curve Germany and GB in 2030



Germany and GB have a renewable share[20] of 38% and 25% respectively in 2030. In Germany the increase in renewables results in about 48 hours of zero or low prices when renewables set the price and there is no need for additional thermal generation. In GB the increase in renewables has little effect in terms of zero/low price hours[21], and renewables set the price in less than 0.1% of the hours during the year.

The occurrence of high price hours is also very similar in 2015 and 2030 for the GB. In Germany however there is a higher occurrence of high price hours, indicating a drop in the regional capacity margin towards 2030, and in Germany this gives an average scarcity rent of about 10 €/MWh. However, the flat duration curve for both Germany and the GB shows that the wholesale price is mostly set by thermal plants (e.g. coal and CCGTs) during the year.

Both duration curves shifts upwards from 2015 to 2030. This is mainly due to the increase in gas and CO2 prices which increase the short run marginal cost (SRMC) of CCGTs and coal. This impacts the wholesale power price when carbon emitting technologies and gas plants set the price.

3.2 Energy efficiency scenario

In the Energy Efficiency (EE) scenario total EU electricity demand increases up to 2020 and then decreases linearly at an annual rate of 1.1% from 2020-2030. Demand falls from 3402TWh in 2020 to 2860TWh in 2030. In 2030 electricity demand in the EE scenario is 561TWh (16%) lower compared to the Base scenario.

The overall effect of this decreased demand is therefor to (a) delay the need for new capacity; (b) provide a large quantity of 'free' power sector abatement, putting downward

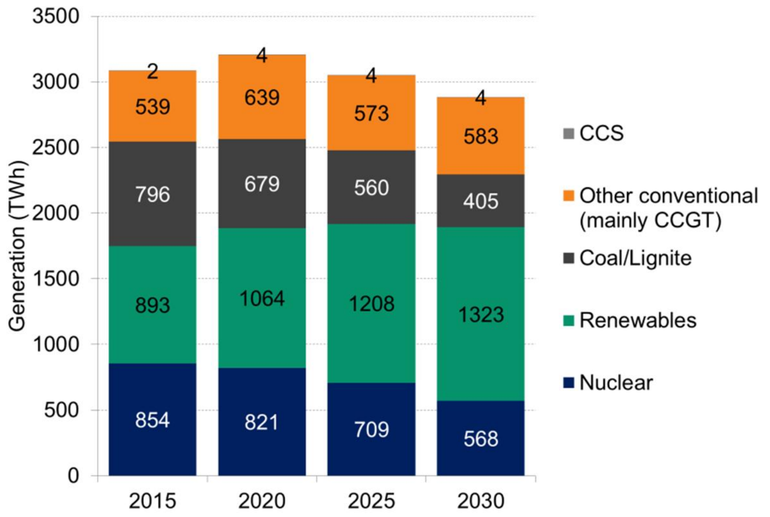
[20] Renewable share of total electricity demand

[21] We note, however that this is for 2006, an average weather year. More extreme weather years yield more zero prices

pressure on carbon prices; and (c) allow power plants with lower marginal cost to set the price more frequently.

Figure 24 shows the evolution of the generation mix from 2015 to 2030 in the EE scenario.

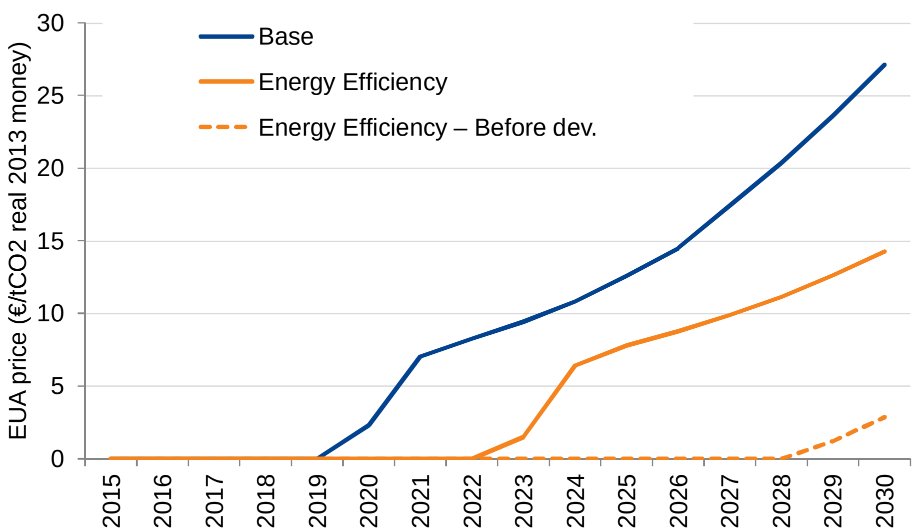
Figure 24 – EU generation mix Energy Efficiency scenario (TWh)



As renewable investments are the same as in the Base scenario the share of renewable generation naturally increases with the lower demand assumptions - RES generates 46% of electricity in 2030. The share of conventional generation is reduced from 37% to 34% as existing capacity retires, but is not replaced to the same extent as in the Base.

Figure 25 shows the results for the carbon prices in the energy efficiency scenario before and after the scenario is developed with a realistic market reaction.

Figure 25 – Carbon price Energy Efficiency scenario vs. Base (€/tCO2)

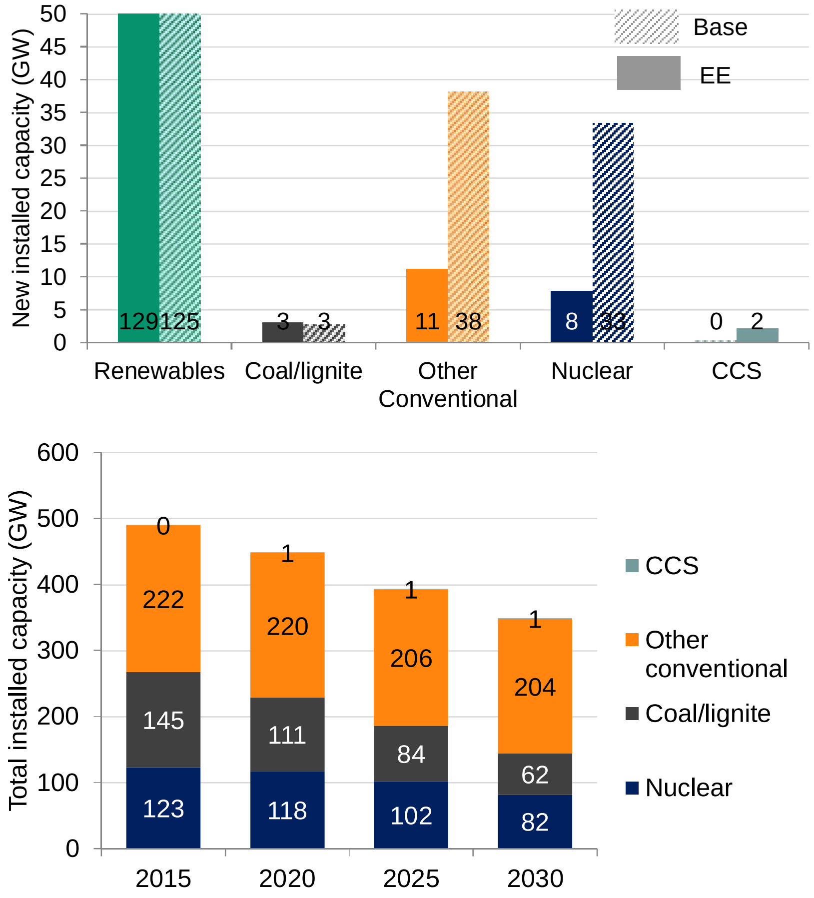


The dotted line represents the straight effect that applying the package would have if the market didn't react to increased Energy Efficiency. However, this dotted line is not internally consistent and the solid line represents the scenario once a realistic market reaction in included. The market tends to react to reduce the impact of perturbations. Lower carbon prices lead to a shift in the balance of low vs. high-carbon new investments, increasing carbon prices back towards the Base.

The reduction in demand caused by energy efficiency measures removes the emissions associated with 561TWh of electricity generation from the EU ETS. Before the scenario is developed (i.e. the change has been made to demand, but the investment decisions by the market in response to that change have not yet been made), carbon prices are very low – not rising above zero until 2029. When a realistic market reaction is modelled the capacity mix changes and the carbon price is supported upwards, but still remains substantially below the Base scenario. The carbon price of the fully developed (and consistent) scenario is therefore €11.4/tCO2 higher in 2030 compared with the undeveloped scenario and €12.9/tCO2 lower than the Base.

Figure 26 shows the capacity development comparison between the Base and the EE scenario (axis cut at 50GW), and total installed thermal capacity in 2015 to 2030.

Figure 26 – Thermal installed capacity and investments (GW)



Applying energy efficiency directly to the Base scenario, with no change in investment input, would lead to very high overcapacity across all EU countries and low profitability for existing and new capacity. The market response to a drop in demand is therefore, first and foremost, to build less capacity. New thermal investments from 2020 to 2030 add up to 23GW, which is 54GW (70%) lower than in the base. The majority of new build in the base case was a mixture of CCGT and nuclear. In the EE scenario, the drop in demand is so severe that there is limited room for either of these technologies.

Table 4 shows the first major (above 200MW) generic[22] investments for selected countries after 2020. These investments exclude named capacity in the pipeline.

Table 4 – First investment post-2020 for selected countries (≥ 200MW)

Country	**France**	**Germany**	**Hungary**	**Poland**	**GB**
EE					
Investment Type	CCGT	Lignite	Lignite	CCGT	CCGT and OCGT
Capacity (MW)	1000	350	250	1000	2800
Year	2026	2035	2029	2024	2020
Base					
Investment Type	CCGT	CHP gas	Lignite	OCGT	CCGT
Capacity (MW)	1200	500	500	1000	3000
Year	2023	2020	2023	2020	2020

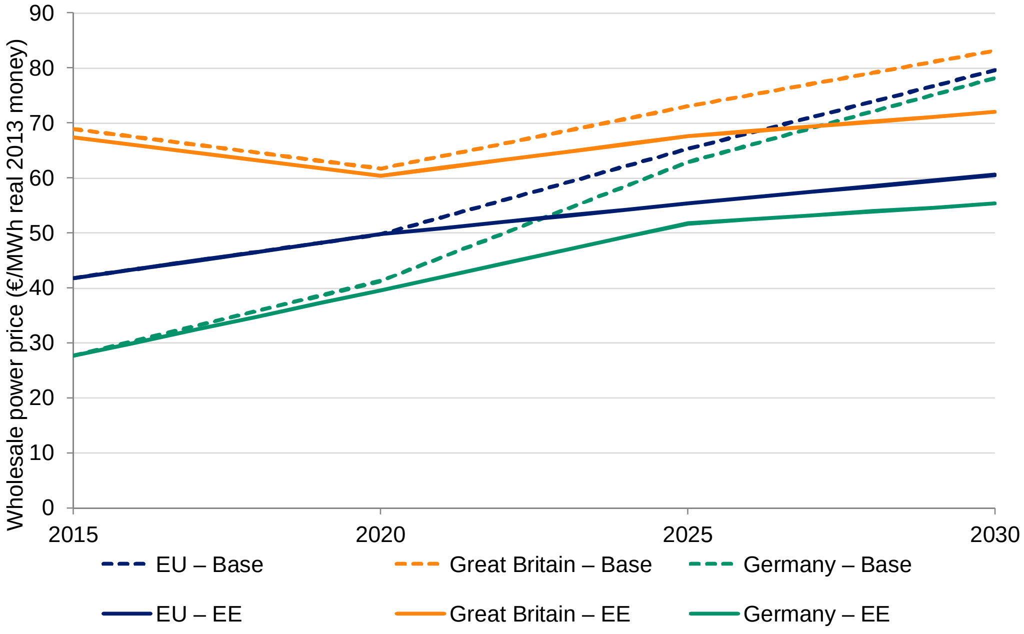
A large share of investments in the EE scenario comes from Eastern Europe where there is still a need for new capacity, even with the overall fall in EU electricity demand. Some of this new investment is already in the pipeline, including 4.7GW of nuclear capacity to be commissioned before 2030. Also, for some Eastern European countries generic investment in conventional capacity is needed before 2030, whereas for most of the other Member States a large share of investments is delayed until after 2030.

Reduced quantities of nuclear on the system increase the generation required from higher carbon technologies (e.g. existing coal and CCGT), putting upward pressure on carbon prices. A key driver of carbon prices is the investment in coal plants which materialises in the decade starting in 2030 as a result of the Energy Efficiency scenario – these coal plants provide a relatively cheap abatement source.

Figure 27 shows the demand weighted average wholesale prices for the EU, Germany and the GB.

[22] The term generic refers to plant build economically during the scenario development. This contrasts with named projects that are under construction and will be built regardless of economics.

Figure 27 – Average wholesale electricity prices, EE- vs Base scenario (€/MWh)



Average annual wholesale prices are the same in the EE and Base scenario up 2020, as there is no change in capacity input and demand up to this point. The difference between the European wholesale price in the EE scenario is €19/MWh below the Base in 2030.

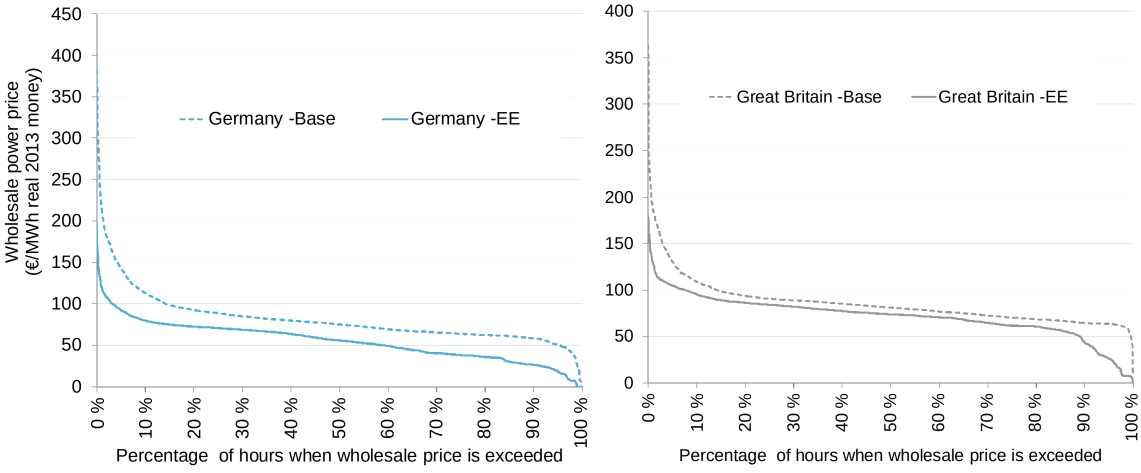
The following factors contribute to lower wholesale prices across Europe:

- **Lower carbon prices**; the carbon price is equivalent to a fuel cost for carbon emitting technologies, so lower carbon prices mean the SRMC for carbon emitting plants is reduced
- **Power plants with lower SRMC set the price for more hours**; with lower demand there is less need to utilise all capacity in the system and in particular coal plants set the price more often than in the Base. Following the merit order curve power plants with lower SRMC will meet demand before plants with higher SRMC, thereby bringing down the average short run cost of meeting demand.
- **Low scarcity rent**; Decreased peak demand means very little new capacity is required in most countries for several decades (see Table 4). Overcapacity supresses wholesale prices by preventing generators from bidding above their SRMC. Put another way, in energy-only markets, where the value of capacity is reflected in the wholesale price, overcapacity reduces this value, suppressing wholesale prices.

The driver for the average EU increase in wholesale prices is the need for new capacity to enter the market and replace plants that are being phased out in countries with currently low capacity margins. Also gas prices increase by almost €10/MWh from 2015 to 2030, thereby increasing the marginal cost of meeting demand with gas plants in the system.

Figure 28 shows the duration curve for Germany and the GB in the Base and EE scenario.

Figure 28 – Duration curve Germany and Great Britain in 2030, EE vs. Base



The duration curve for both Germany and GB shows a shift downwards, and this is mainly due to the factors already mentioned above. The shape of the duration curve for GB is very similar to the Base scenario but with an increase in low price hours and reduced number of high price hours. This gives an average annual wholesale price of €11/MWh below the Base scenario in 2030.

With the increased share of renewables there are a higher number of zero/low price hours in Germany and the GB. The EE renewable share is 52% in Germany and 37% for the GB. Prices in Germany are below €10/MWh for 3% of the hours, and in the GB for 2% for the hours.

The German duration curve shows the same pattern as the GB in terms of extreme prices, but a more pronounced shift downwards in the duration curve. Overcapacity and the renewable share in Germany are higher compared to GB, resulting in a more significant drop in prices. In Germany the EE average annual wholesale price is €23/MWh lower than the Base scenario in 2030.

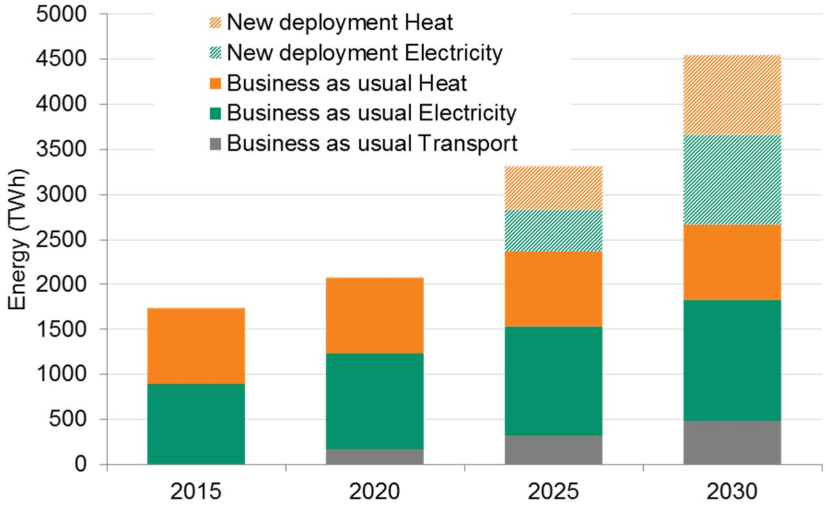
3.3 RES scenario

In the RES scenario 27% of EU primary energy demand comes from renewable generation. Compared to the Base scenario this requires an additional 1877TWh of new renewable heat and electricity to enter the market by 2030. We use the Pöyry Eureno model to determine the cost optimal distribution between different renewable technologies around the EU, and the split between renewable heat and electricity (see Annex A.3 for detailed model description of Eureno).

The overall effect of forcing more renewable electricity into the system is (a) delaying the need for new capacity; (b) forcing a large quantity of zero emitting generation into the system, putting downward pressure on carbon prices; and (c) allow power plants with lower SRMC to set the price more often.

Figure 29 shows the evolution of renewables in the electricity, heat and transport sector, including the output new build from Eureno.

Figure 29 – Renewable energy in electricity, heat and transport (TWh)



We assume that renewable transport can contribute 498TWh by 2030. This leaves a requirement for 1877TWh of new renewable generation from the heat and electricity sector up to year 2030. Eureno finds that 53% of the contribution comes from the electricity sector and 47% from the heat sector.

The overall impact of the RES target is similar to that seen in the Energy Efficiency scenario, delaying the need for other new capacity, and injecting large a large volume of zero carbon generation. There is a subtle difference, though, in the effect of EE and RES targets on the *need for new capacity* and the *displacement of high-carbon generation*:

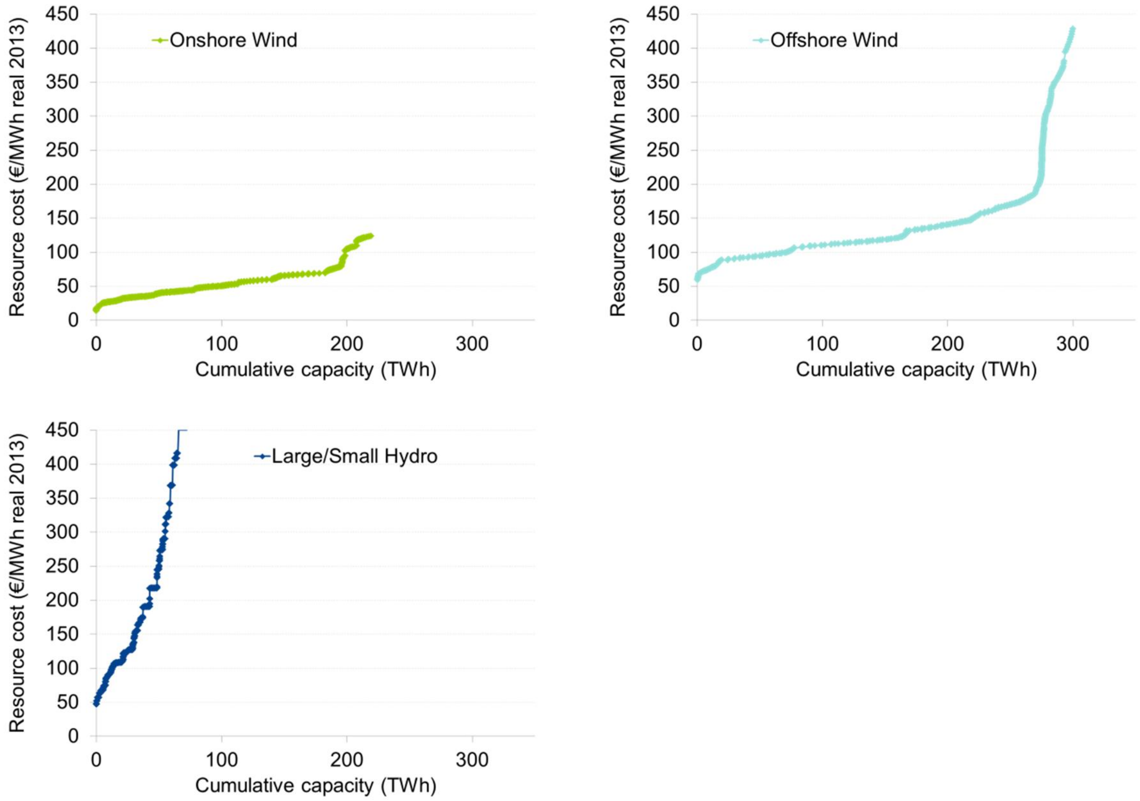
- **Impact on need for new capacity***:* The RES target results in a **smaller** reduction (52GW) in the need for new build than the EE target (23GW)
- **Impact on displacement of high-carbon generation**: The RES target results in a displacement of 873TWh of high-carbon generation, which is **greater** than the 561TWh of demand removed by energy efficiency measures.

With no increase in renewable investments the total share of renewables is less than 14% in 2030. It should be noted the projected increase in primary energy demand is 1377TWh from 2020 to 2030, meaning that the relative increase in renewables adds up to 873TWh in total.

3.3.1 Renewable build out – the European supply curve

Figure 30 shows the European RES supply curves for new build up to 2030 for selected technologies.

Figure 30 – European supply curve; selected renewable technologies



In the Eureno model we aggregate the renewable supply curve for each EU member to get an overall European supply curve for new investments in renewable generation. The supply curve is based on resource cost of each technology, this is calculated as the long run marginal cost (LRMC) for each technology in each country minus the wholesale price. For detailed information on cost assumptions of renewable technologies see Annex B.

Investment cost for renewables are mainly differentiated by country based on civil engineering and construction costs. This means that countries with lower labour cost have a lower cost of construction. Hurdle rates also differ by country, based on S&P's ratings e.g. a country with an S&P rating of AA will have a lower required rate of return than a country with a BBB rating. For technology specific required rates of return this is determined by the technological maturity and operational risk for that technology. Some investment costs are expected to fall over time as the technology matures.

The supply curves illustrated in Figure 30 only show potential and the cost for wind-, solar- and hydro technologies. The Eureno supply curve also includes heat and other technologies such as biomass, biogas, biowaste, geothermal, wave and tidal technologies. The potential for less mature technologies such as wave and tidal (with the exception of tidal barrage plants) is not utilised in our scenarios under the least cost approach in Eureno, as these technologies are found far out on the supply curve. Some of these technologies could still be deployed, but through targeted publicly funded programmes and not through what would be a European least-cost build out approach.

The actual build out of renewables, and the technical and geographical distribution, is determined by where the demand for (new) renewables crosses the EU supply curve.

3.3.2 Renewable deployment and curtailment challenges

High penetration of intermittent capacity can lead to curtailment challenges. Curtailment situations can occur when renewable generation exceeds demand, when there are local or regional congestion issues on the grid, or due to operational issues[23].

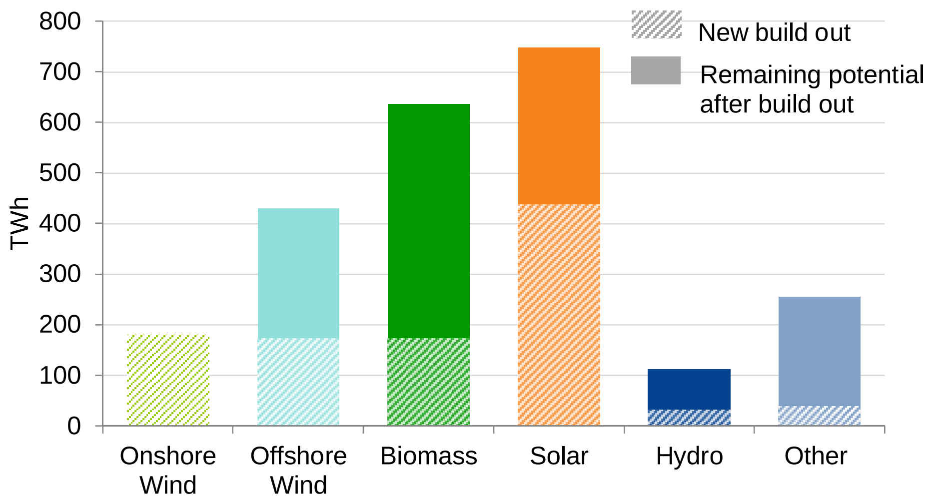
When the RES deployment suggested by Eureno was implemented in BID (which models a greater granularity of RES output, being an hourly model), significant quantities of curtailment were observed in some markets. Several responses are available in building the scenario:

- Accept curtailment and the lower load factors
- Increase demand in response to the low prices that naturally occur with larger quantities of renewables (for example, increased electric heating, or demand side response)
- Increase interconnection capacity in response to the low prices that naturally occur with larger quantities of renewables
- Shift renewable deployment in one country to a different sector (e.g. heat) or a different country, on the assumption that the economics of building more RES in a country with significant curtailment is unlikely to be as economic as Eureno first estimated

3.3.3 Results

Figure 31 shows the RES build in the period 2020 to 2030 (in addition to what is built in the base) and the remaining potential for each technology.

Figure 31 – Renewable electricity build out and potential from Eureno (TWh)



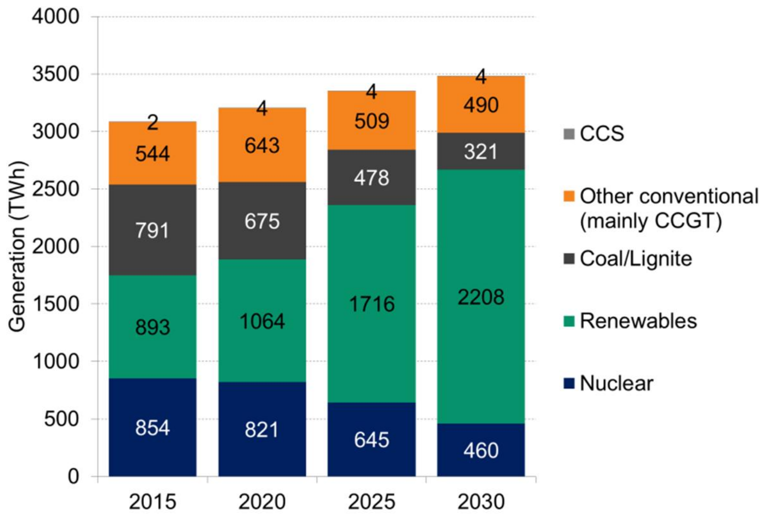
New renewable investment in the electricity sector is distributed between all technologies and all EU member states. The full 2030 potential for onshore wind (179TWh) is deployed as this is one of the most cost efficient and mature technologies. New solar generation

[23] E.g. large deviations in planned and actual generation

gives the highest contribution with more than 430TWh of new generation, and this is mainly distributed to areas with high solar irradiation. Remaining potential for solar is mainly found in the Northern European region, where low solar irradiation gives a higher cost per MWh. The biomass category includes biomass electricity (e.g. with pellets fuels), biowaste and biogas. The biomass category therefore includes several high-cost technologies, which are not deployed. The remaining potential for biomass adds up to 462TWh in 2030. Only 33TWh of hydro generation enters the system. The total hydro potential is small relative to other technologies, as hydro resources are already highly utilised across the EU. The potential for large scale hydro is limited, and new build mainly consists of small scale, more expensive plants (per MWh produced). It should be noted that the hydro potential does not include upgrading of existing plants. The Other category includes geothermal capacity and less mature marine technologies (wave and tidal). The total build out in this category is 39TWh, where 72% comes from geothermal. In total the new renewable investments in the electricity sector add up to 873TWh from year 2020 to 2030.

Figure 32 shows the evolution of the EU generation mix up to 2030 in the RES scenario.

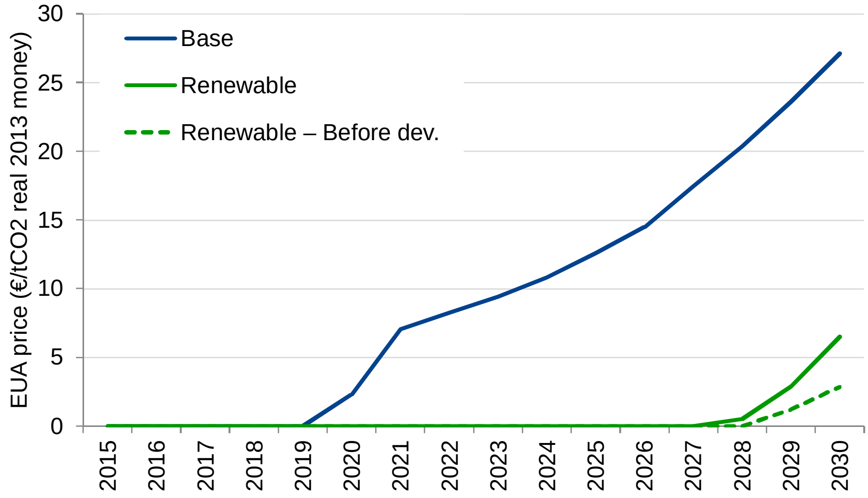
Figure 32 – EU generation mix Renewable scenario (TWh)



With 873TWh of renewables forced into the power system the renewable share of EU generation is 63% in 2030. As the bidding price for renewable generators in our modelling is zero this pushes out generation from conventional power plants and thermal generators. There is an absolute reduction in thermal power plant generation of 814TWh from 2020 to 2030 (including nuclear).

Figure 33 shows the results for the carbon price in the Renewable scenario before and after scenario development.

Figure 33 – Carbon price Renewable scenario vs. Base (€/tCO2)

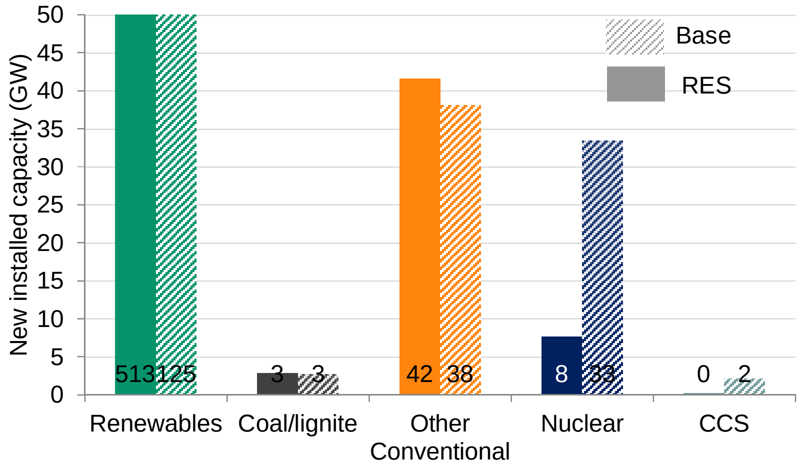


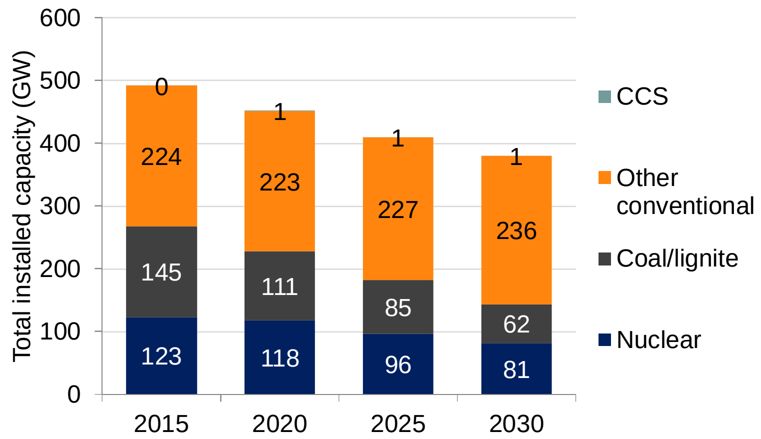
The RES scenario adds 873TWh of zero emission generation and this has a significant downward effect on the carbon price. The price of CO2 before scenario development is €2.9/tCO2 in 2030. The low carbon price increases the relative profitability of carbon intensive technologies, and the market reacts by increasing carbon emitting generation in the power mix. For the developed scenario the carbon price is therefore somewhat higher, but the carbon price still remains at zero up to 2027 and reaches €6.5/tCO2 in 2030.

The price impact on CO2 is more severe in the RES scenario than in the EE scenario. This is mainly due to more zero generation entering the system (873TWh) compared to the drop in demand in EE which is equivalent to 561TWh.

Figure 34 shows new thermal and renewable capacity entering the market between year 2020 and 2030 (axis is cut at 50GW), and total installed thermal capacity from 2015 to 2030.

Figure 34 – Installed thermal capacity and investments (GW)





Note that the axis of the top graph is cut to improve readability

Total thermal (non-renewable) investments and repowering add up to 52GW in the RES scenario, and this is 24GW less compared to the Base. This is due to the renewable capacity being forced into the system, which delays the need for other new investment.

Due to the low carbon price the profitability of nuclear plants is reduced relative to other more carbon intensive technologies. As a result nuclear investments are reduced by 25GW –more than the absolute reduction in new thermal investments relative to the Base. With low carbon prices investments are shifted from zero-carbon technologies to more carbon intensive generation. Investments in CCGTs and OCGTs are 4GW higher in the RES scenario, whilst investments in coal/lignite are equal to the Base scenario. A large share of investment post-2030 is in coal and lignite.

Table 5 shows the first major generic investment (above or equal to 200MW) for selected countries after 2020. As for the other scenarios these investments excludes named power plants in the pipeline.

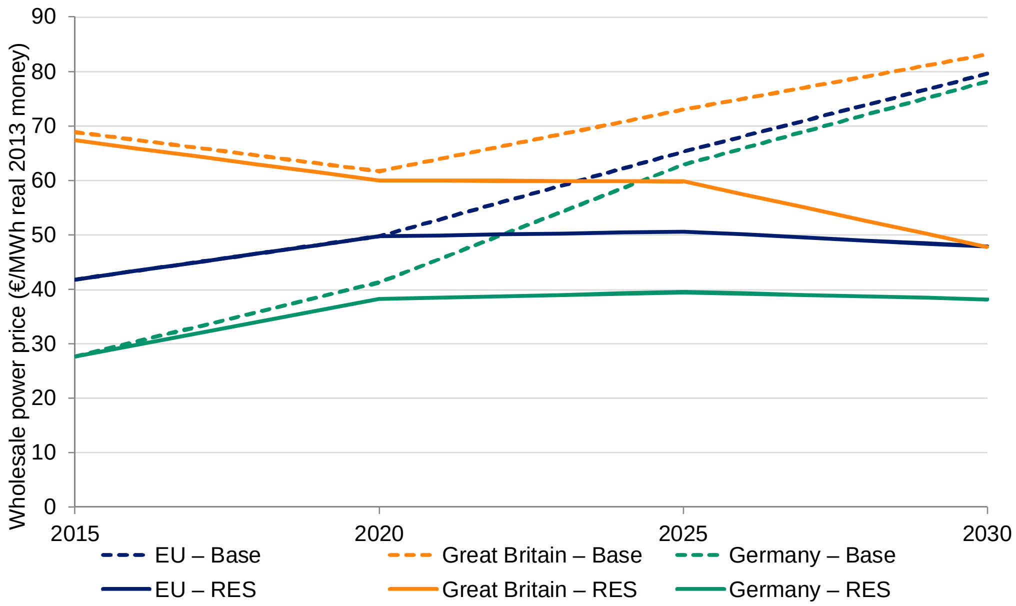
Table 5 – First investment post-2020 for selected countries (≥200MW)

Country	France	Germany	Hungary	Poland	GB
RES					
Investment Type	CCGT	–	Lignite	CCGT and Lignite	CCGT
Capacity (MW)	1200	–	1200	2250	1000
Year	2023	–	2035	2035	2020
Base					
Investment Type	CCGT	CHP gas	Lignite	OCGT	CCGT
Capacity (MW)	1200	500	500	1000	3000
Year	2023	2020	2023	2020	2020

Due to overcapacity there is no need for new generic investments in some countries (e.g. Germany and the Baltics). In most countries investment decisions are delayed to after 2030.

Figure 35 shows the average wholesale power price for the EU, Germany and GB.

Figure 35 – Average wholesale prices, RES- vs. Base scenario (€/MWh)



Demand weighted wholesale power prices for the EU increase up to 2020 and then remain flat at €50/MWh from 2020-2025. Prices start to decrease post-2025, and end up at €47.8/MWh in 2030. The price impact varies across the different EU countries, depending on how much renewable generation is entering the system.

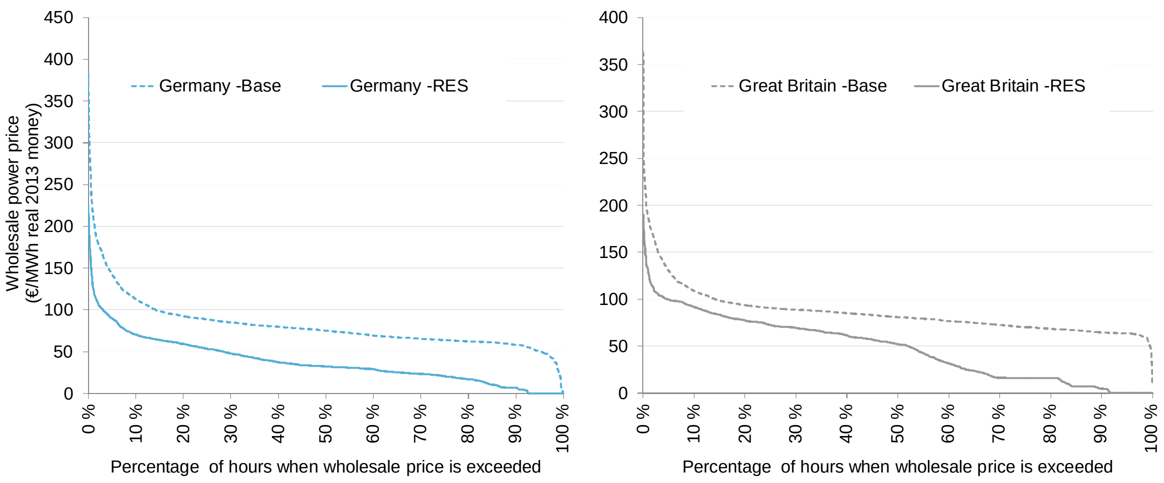
The lower wholesale prices compared to the base are mainly driven by:

- **Sharp decline in the carbon price**; this reduces the marginal cost for carbon emitting thermal generators, and lowers the wholesale price in hours where these plants set the price.
- **Large increase in intermittent renewable production**; renewable generators set the wholesale price in more hours over the year. With SRMC close to zero this reduces average annual wholesale price.
- **Low scarcity rent**; The introduction of large quantities of renewable capacity delays the need for new build in most countries. Overcapacity supresses wholesale prices by preventing generators from bidding above their SRMC.

In both Germany and GB the large entry of renewables contributes to overcapacity in the market. The two countries has a similar evolution in wholesale prices compared to the overall EU average up to 2025, but GB has a significant drop in prices of €12/MWh from 2025 to 2030. This is mainly due to the second of the above points, as the renewable share increases from 29% in 2020 to 69% in 2030. In Germany the renewable share increases from almost 30% in 2020 to 49% in 2030.

Figure 36 shows the duration curve for Germany and GB in 2030.

Figure 36 – Duration curve Germany and Great Britain in 2030, RES vs. Base



In both Germany and GB the duration curve shifts downwards – meaning lower average wholesale prices. This is due to the lower carbon price –reducing the marginal cost of thermal plants, the increase in renewables setting the price for more hours during the year and thereby pushing out generation from less efficient thermal plants, and the overcapacity which reduces the scarcity rent in the market.

The large increase in low cost renewable generation has a big impact on the number of zero/low price hours over the year for both Germany and GB. The price is set by renewables in 7% of the hours in Germany, and in 17% of the hours in GB.

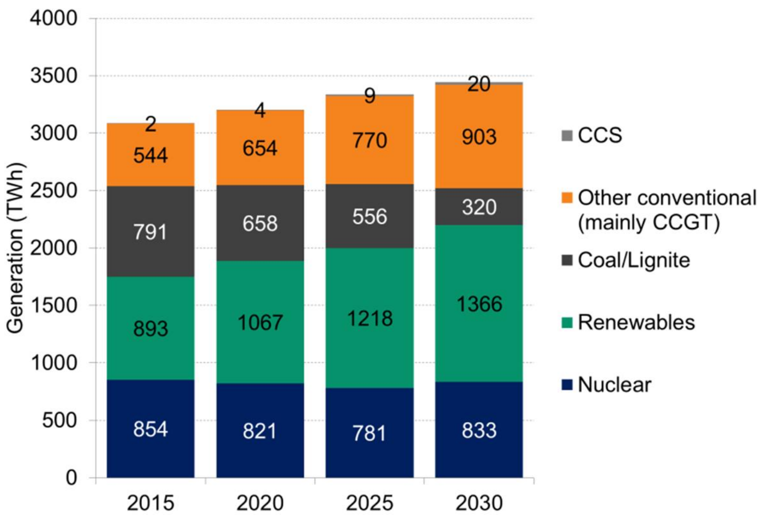
For Germany there is a significant drop in the number of high price hours. This is due to the already mentioned drivers of overcapacity and low scarcity rent. In GB the drop is less severe for high price hours, this is because GB is a capacity market and scarcity rent is limited even in the Base scenario.

3.4 Carbon scenario

In the Carbon scenario the ETS emission cap is decreased from an annual factor of 1.74% to 2.2% in the period after 2020, and the carbon market is to deliver 40% reductions in emissions relative to 1990 levels. No zero-emission generation is forced into the system, and demand is equal to the Base scenario. The overall effect of this tighter ETS cap is to (a) increase carbon prices; and (b) shift investments to less carbon intensive technologies.

Figure 37 shows the evolution of the EU power mix up to 2030.

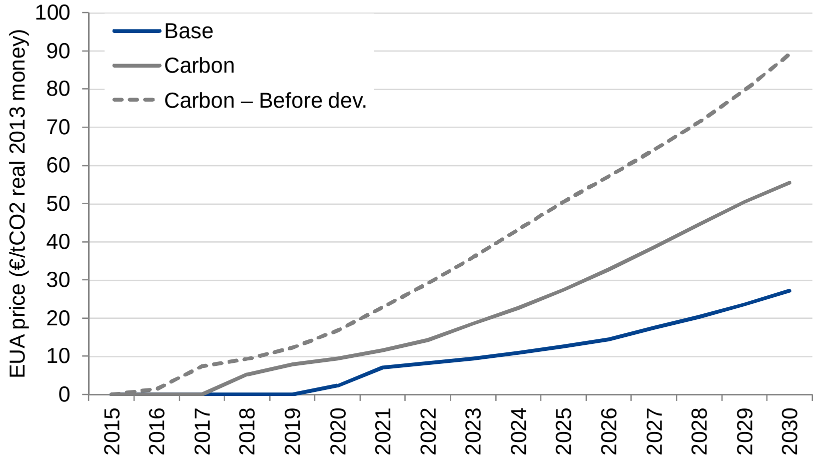
Figure 37 – EU generation mix Carbon scenario (TWh)



There is an absolute increase in nuclear generation from 2015 to 2020, but the nuclear share drops from 26% in 2015 to 24% in 2030. Relative to the Base, though, nuclear generation is higher and coal and lignite generation lower. The renewable share increases from 29% in 2015 to 40% in 2030. This is marginally higher than in the Base (39%), since the higher carbon price brings on a small amount of additional RES.

Figure 38 shows the results for the carbon price in the Carbon scenario before and after development.

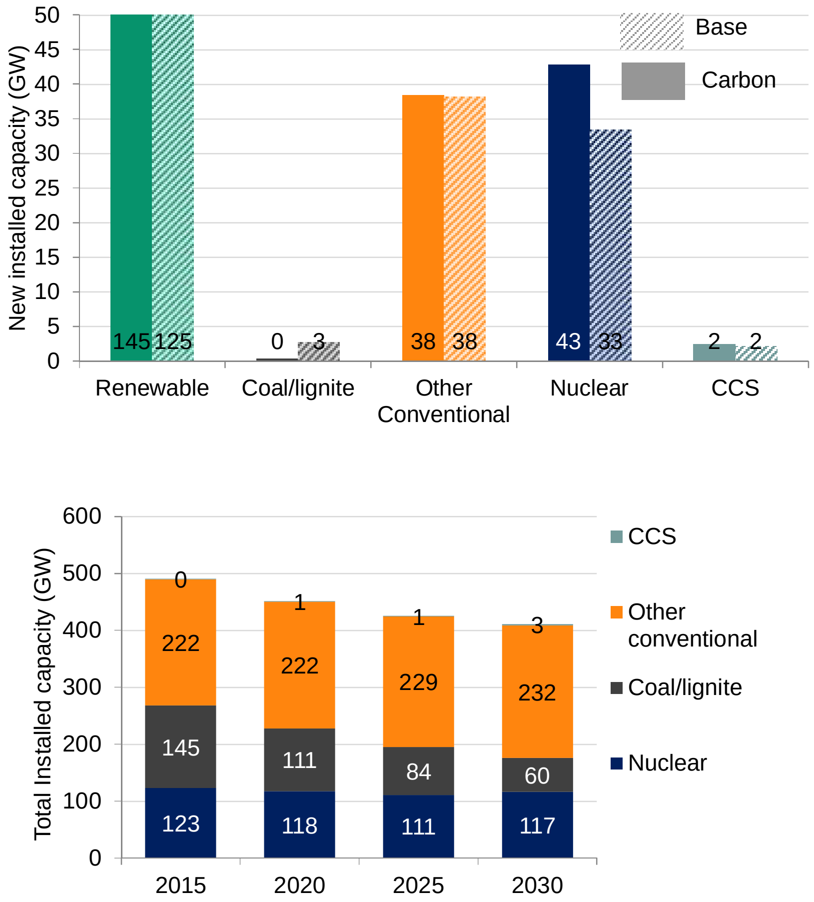
Figure 38 – Carbon prices in the Carbon and Base scenarios (€/tCO2)



A tighter emissions cap increases demand for abatement, and results in higher carbon prices relative to the Base. Applying the Base capacity mix to the Carbon scenario the carbon prices would increase to about €89/tCO2 in 2030. However, as a response to high carbon prices the carbon intensive capacity is replaced by nuclear and renewables, and this brings the carbon price down to €55/tCO2 in 2030. Still, the price remains €28/tCO2 higher than the Base scenario in 2030.

Figure 39 shows investments in thermal and renewable capacity for the Base and the Carbon scenario (axis cut at 50GW), and total installed thermal capacity from 2015 to 2030.

Figure 39 – Installed thermal capacity and investments (GW)



Note that the axis of the top graph is cut to improve readability

Zero emission capacity becomes more profitable in the Carbon scenario, and this is reflected in the new thermal capacity investments in the period 2020-2030. The Carbon scenario results in 10GW more nuclear capacity relative to the Base, and coal and lignite investments are close to zero (this trend also continues post-2030).

Table 6 shows when the first major generic investments (above or equal to 200MW) occur for selected countries after 2020. This excludes named power plants in the pipeline.

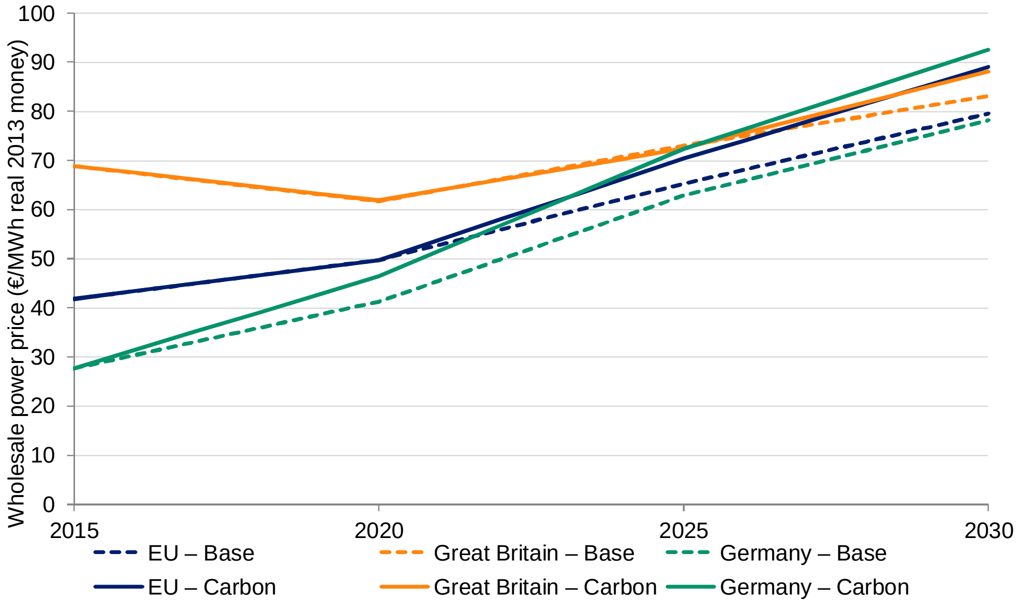
Table 6 – First investment post-2020 for selected countries (≥200MW)

Country	France	Germany	Hungary	Poland	GB
Carbon					
Investment Type	CCGT	CCGT	CCGT	Nuclear	CCGT
Capacity (MW)	1800	300	500	1500	3000
Year	2023	2026	2023	2024	2020
Base					
Investment Type	CCGT	CHP gas	Lignite	OCGT	CCGT
Capacity (MW)	1200	500	500	1000	3000
Year	2023	2020	2023	2020	2020

As there are no factors influencing the need to build more capacity in the Carbon scenario the timing of investments is similar to the Base scenario.

Figure 40 shows demand weighted average wholesale prices for the EU.

Figure 40 – EU average wholesale electricity prices, Carbon vs Base (€/MWh)



The demand weighted EU wholesale price in the Carbon scenario is €9.5/MWh higher in 2030 compared to the Base.

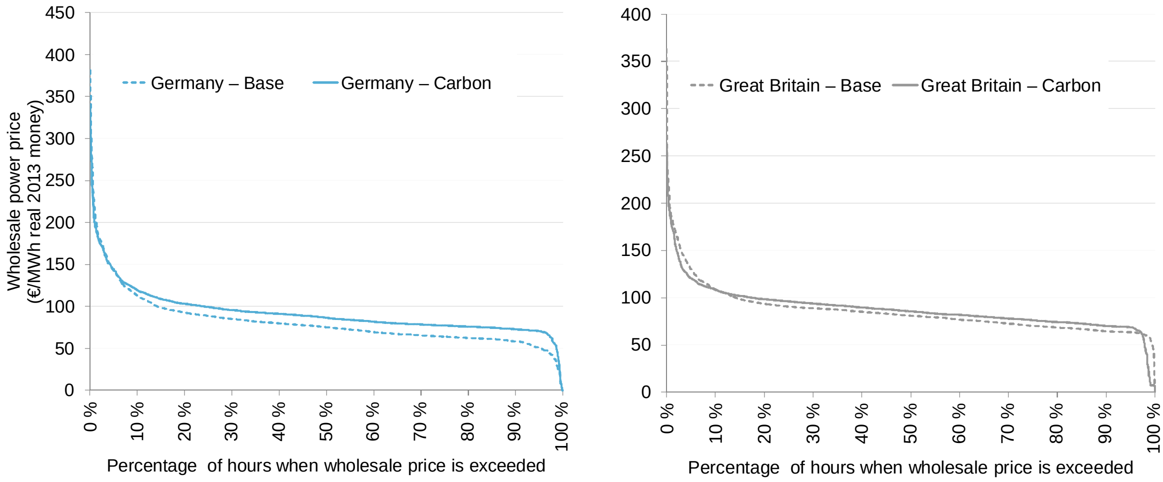
The following factors contribute to higher wholesale prices across Europe:

- **Higher carbon prices**; a higher carbon price increase the SRMC for carbon emitting plants. This contributes to a higher wholesale price when these plants set the price.

In the Carbon scenario wholesale prices increase by almost €5/MWh in GB and €14/MWh in Germany. The impact is higher in Germany due to a higher carbon intensity in the energy mix. Whereas GB can shift investments to nuclear, this is not an option for Germany and more than 53% of generation comes from conventional capacity in 2030.

Figure 41 shows the duration curve for Germany and GB.

Figure 41 – Duration curve Germany and Great Britain in 2030, Carbon vs. Base



The duration curve for Germany and GB shows a small upward shift in the duration curve, and this is caused by the higher carbon prices.

The number of zero/low price hours is very small for both countries, with 0.45% and 1% for Germany and GB respectively. This is due to the relatively small share of renewable generation in the Carbon scenario, with a total of 40% across the EU -only 1% higher than the Base scenario. The reduced share of zero/low price hours in German contributes to an increase in average wholesale prices. There is a small increase in low price hours for GB, but this has little impact on the average wholesale price.

For (high) extreme prices there is little difference between the Base and Carbon scenario in the two countries. Capacity margins are similar to the Base scenario, and scarcity levels are therefor also similar in the two scenarios.

3.5 Full package scenario

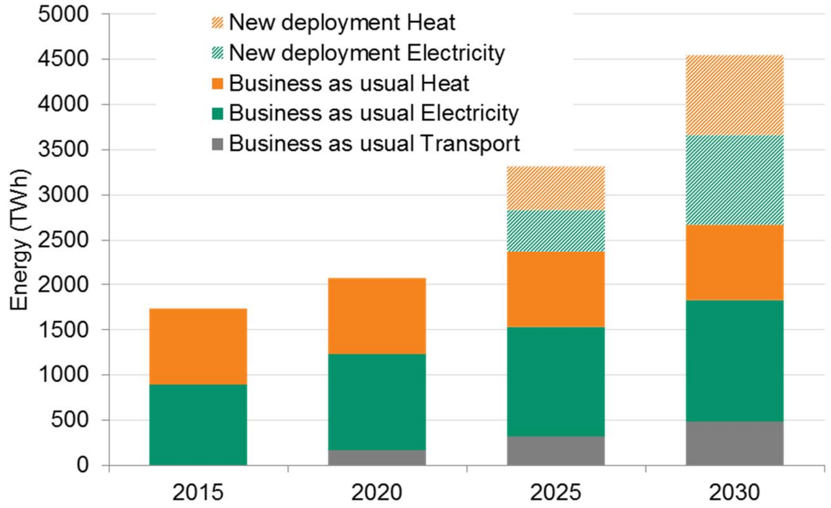
In the Full Package (FP) scenario we include all 2030 targets; energy efficiency (25%), renewable targets (27%) and the new carbon cap applied in the Carbon scenario (43% in ETS sector versus 2005).

The overall effect of applying the whole package is therefore (a) to delay in the need for new capacity; (b) high share of 'free' zero-emission capacity putting downward pressure on carbon prices; (c) tighter emission cap that gives upward support to the carbon price; and (d) allowing power plants with lower marginal cost to set the price more frequently.

In the FP scenario, like in the RES scenario, we use the Eureno model to determine the cost optimal distribution between different renewables technologies, and the split between heat and electricity.

Figure 42 shows the evolution of renewables in electricity, heat and transport in the FP scenario.

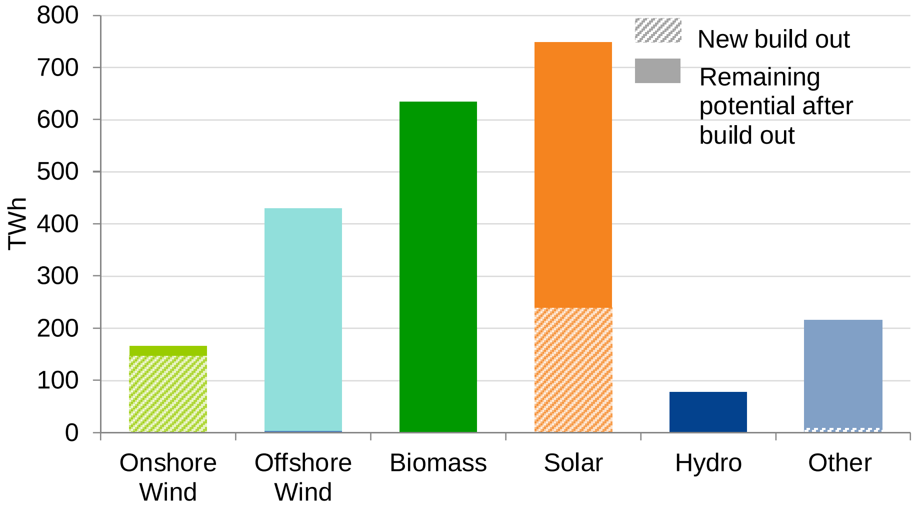
Figure 42 – Renewable energy build out (TWh)



Because of energy efficiency the total build out of renewables is smaller compared to the RES scenario. In total 816TWh of renewable electricity and heat is required to meet the renewables target in the FP scenario, this is 1061TWh lower than the RES scenario.

Figure 41 shows the new build out from Eureno in the FP scenario.

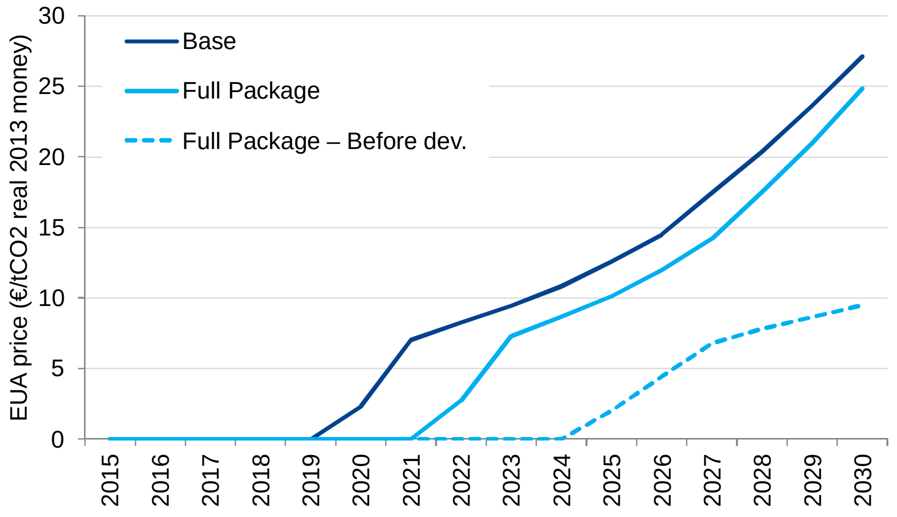
Figure 43 – Renewables electricity build out and potential from Eureno (TWh)



The renewable build out distribution in FP shows the same pattern as in the RES scenario. Wind and solar is the most cost optimal technologies, and therefore accounts for almost 97% of new build out.

In Figure 46 we compare the Full Package carbon price before and after scenario development with our Base scenario.

Figure 46 – Carbon price Full Package scenario vs. Base (€/tCO2)

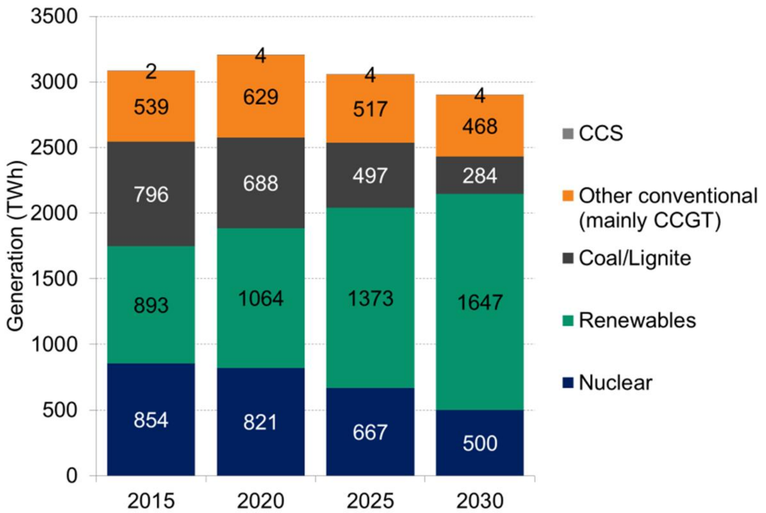


Due to energy efficiency and renewables being “forced” in to the energy mix a total of 862TWh of free abatement and zero emission capacity puts downward pressure on the carbon price. However due to the tighter emission cap there is a need for earlier abatement than in the EE and RES scenario, and this helps support the carbon price, moving prices closer to the Base scenario. In the 2030 the FP carbon price in the developed scenario is €2.3/tCO2 below the Base scenario.

Figure 47 shows the capacity development comparison between the FP and Base scenario from 2020 to 2030 (axis cut at 50GW), and the total installed thermal capacity from 2015 to 2030.

Figure 44 shows the evolution of the generation mix in the EU from 2015 to 2030.

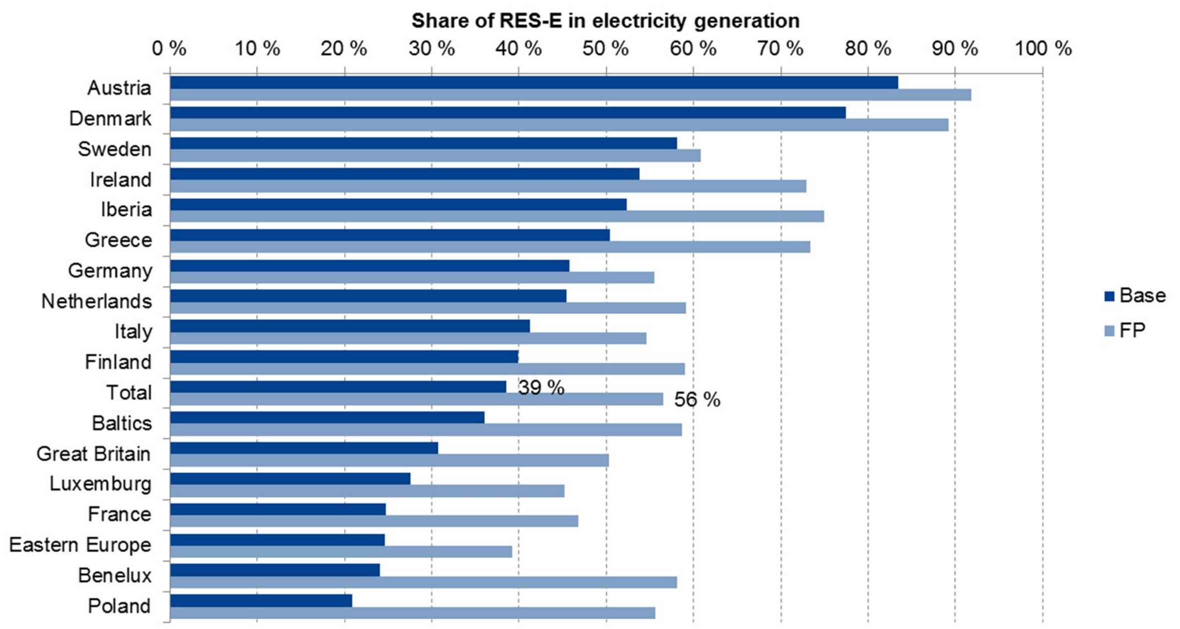
Figure 44 – EU Generation mix Full Package scenario (TWh)



Due to reduced primary energy demand as a result of energy efficiency targets, the absolute need of new renewable capacity to meet the RES target is reduced in the FP (see Figure 17). The renewable target results in an additional 312TWh of renewable generation in addition to the renewable baseline. Generation share from coal and lignite is reduced from 11% to 9%, and generation from other conventional capacity is reduced by 8% relative to the Base in 2030. The renewable share of generation is 56% in that scenario.

Figure 45 shows the renewable share of electricity demand in EU member countries (excluding Luxembourg, Cyprus and Malta).

Figure 45 – Renewable share by country, EU members 2030

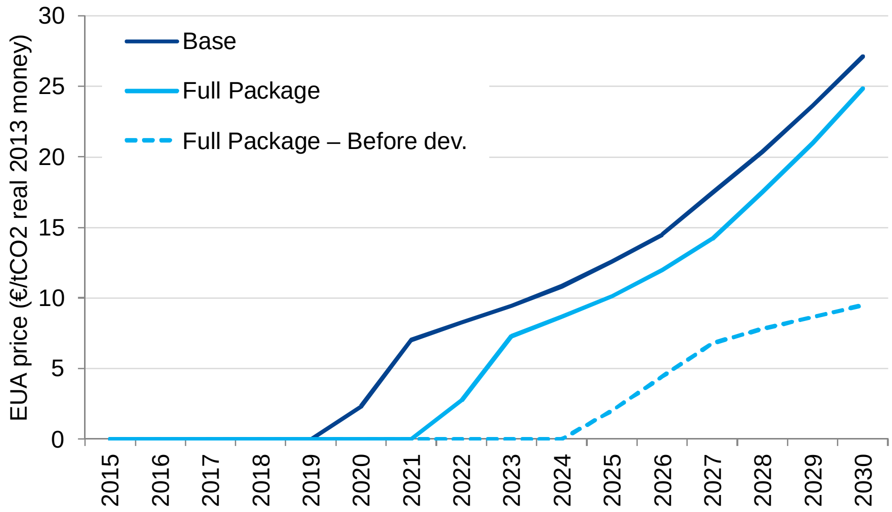


The total renewable share is 56% of electricity demand on an EU level. This is more than the minimum level expected by the European Commision[24], and this figure is highly influenced by the share of renewable energy in the heat and transport sector. The biggest absolute contributor to the renewable share is Germany with an installed renewable capacity of more than 90GW.

[24] The communication (COM/2014/15) from the commission states that "[…] the share of renewable energy in the electricity sector would increase from 21% today to at least 45% in 2030." as a result of the package.

In Figure 46 we compare the Full Package carbon price before and after scenario development with our Base scenario.

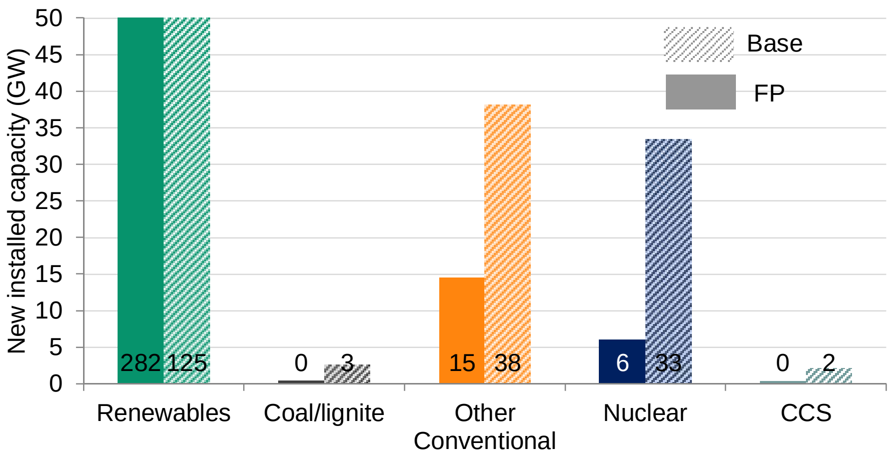
Figure 46 – Carbon price Full Package scenario vs. Base (€/tCO2)

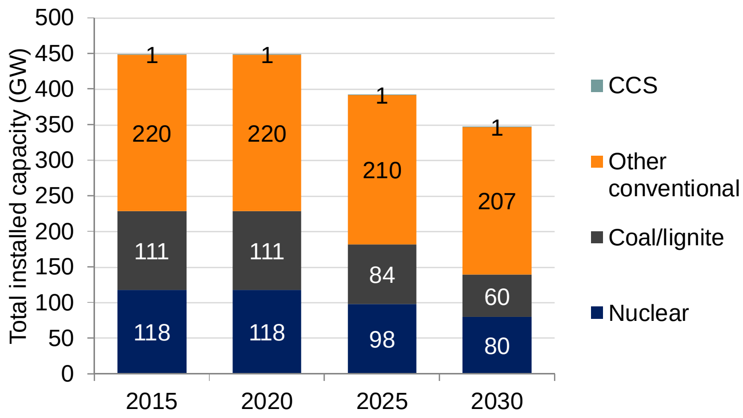


Due to energy efficiency and renewables being "forced" in to the energy mix a total of 862TWh of free abatement and zero emission capacity puts downward pressure on the carbon price. However due to the tighter emission cap there is a need for earlier abatement than in the EE and RES scenario, and this helps support the carbon price, moving prices closer to the Base scenario. In the 2030 the FP carbon price in the developed scenario is €2.3/tCO2 below the Base scenario.

Figure 47 shows the capacity development comparison between the FP and Base scenario from 2020 to 2030 (axis cut at 50GW), and the total installed thermal capacity from 2015 to 2030.

Figure 47 – Installed thermal capacity and investments (GW)





Note that the axis of the top graph is cut to improve readability

Thermal investments from 2020-2030 in the FP scenario is 55GW below the Base scenario. This is due to overcapacity limiting the need for new thermal plants to enter the market before 2030. Investment in coal and lignite is 2.3GW lower than the Base, and investment in CCGTs/OCGTs and nuclear is reduced by 23 -and 27GW respectively. The absolute largest drop in investments is for nuclear capacity, and this is caused by the lower carbon prices making nuclear less profitable relative to conventional plants. Table 7 shows the first major generic investment (above or equal to 200MW) for selected countries after 2020. As for the other scenarios these investments exclude power plants in the pipeline.

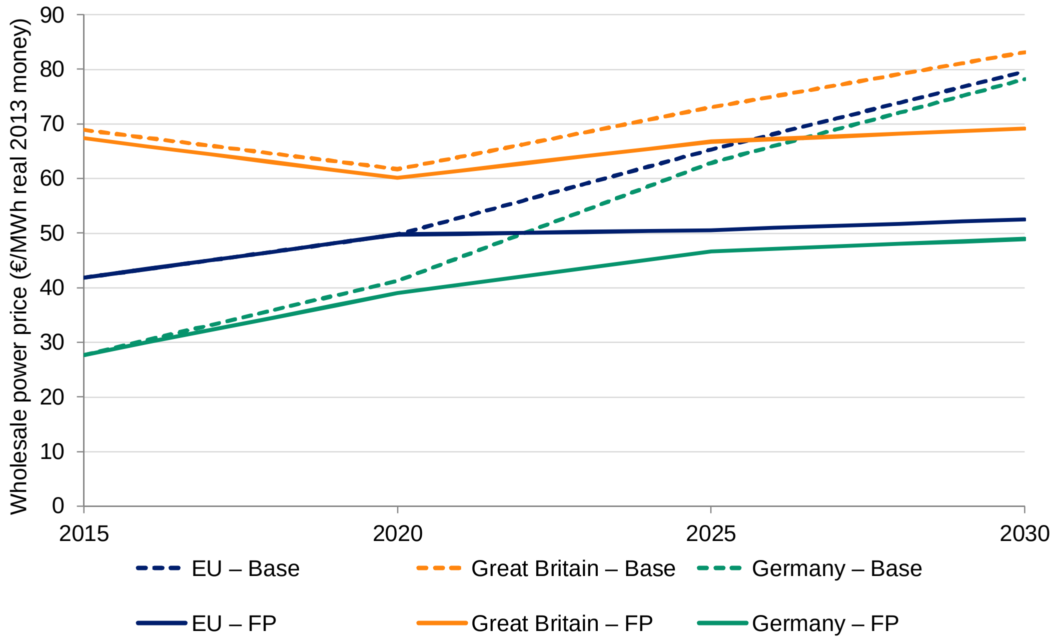
Table 7 – First investment post-2020 for selected countries (≥ 200MW)

Country	**France**	**Germany**	**Hungary**	**Poland**	**GB**
FP					
Investment Type	CCGT	–	Lignite	OCGT	CCGT and OCGT
Capacity (MW)	1000	–	1000	1000	2800
Year	2026	–	2034	2037	2020
Base					
Investment Type	CCGT	CHP gas	Lignite	OCGT	CCGT
Capacity (MW)	1200	500	500	1000	3000
Year	2023	2020	2023	2020	2020

For some countries lower demand and renewable build out results in no need for investments before 2030. Countries with limited overcapacity and renewable share and countries with capacity markets do however build more capacity before 2030. In e.g. Poland and GB first investment is not delayed, but the size (MW) of the investment is reduced.

Figure 48 shows the demand weighted average wholesale prices for the EU, Germany and GB.

Figure 48 – EU average wholesale electricity prices, Full Package vs Base (€/MWh)



Average EU wholesale power prices remain almost flat from 2020 to 2030. The difference between the European wholesale price in the FP and Base scenario is €27/MWh in 2030.

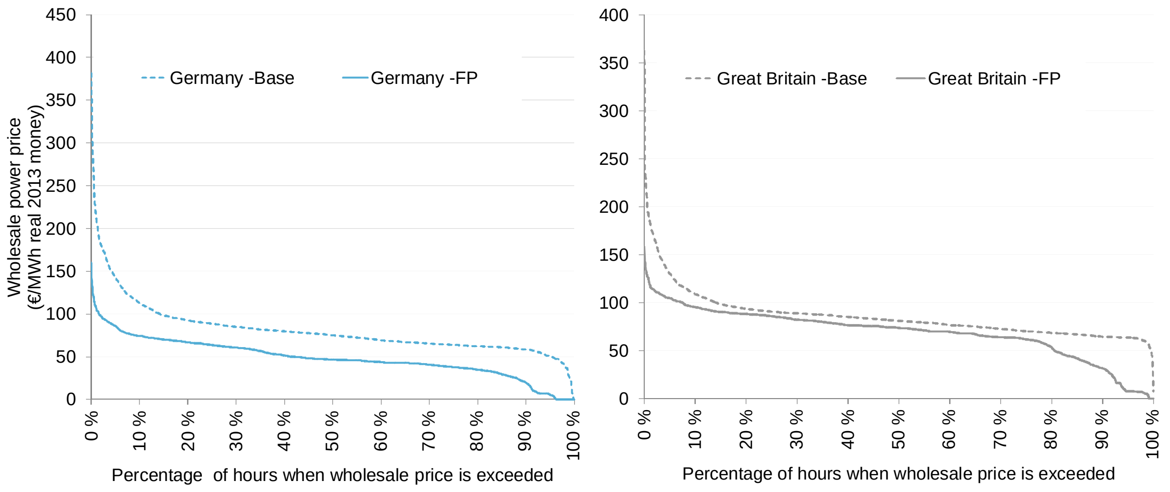
The following factors contribute to lower wholesale prices across Europe:

- **Lower carbon prices**; the lower carbon prices puts downward pressure on the wholesale price as the SRMC for carbon emitting plants is reduced.
- **Power plants with lower SRMC set the price for more hours**; with lower demand and more RES capacity there is less need to utilise thermal capacity in the system and in particular coal plants set the price more often than in the Base. Power plants with high SRMC will be forced out of the merit order curve reducing the cost of meeting demand.
- **Low scarcity rent**; due to overcapacity generators cannot bid into the wholesale market above their SRMC. This puts downward pressure on the wholesale price in peak demand hours.

Overcapacity in Germany is persistent, and this causes a large drop in wholesale prices at €29.3/MWh relative to the Base. The drop in prices for GB is less severe at €14/MWh in 2030. This is because GB has a capacity market, meaning 'scarcity rent' is already close to zero in 2030, even in the base.

Figure 49 shows the duration curve for Germany and GB in the FP and Base scenario.

Figure 49 – Duration curve Germany and Great Britain in 2030, FB vs. Base



The duration curve shifts downwards in both Germany and GB. The downward shift is larger in Germany, and this is mainly due to a higher share of renewables compared to GB. Also Germany has a higher share of coal and lignite in the energy mix, meaning that the drop in carbon prices to a larger extent is reflected in the hourly wholesale price.

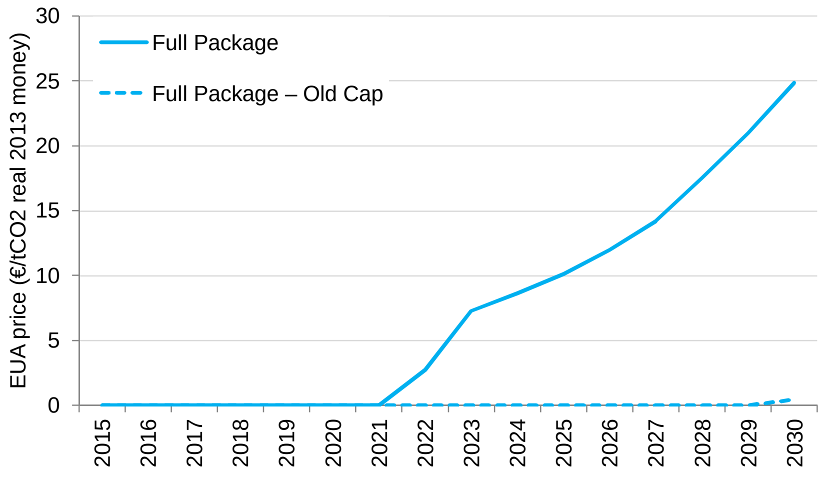
The number of zero/low price hours increase for both countries in the FP scenario. The share of low price hours is almost 9% for Germany and 6% in GB.

The number and level of high price hours is also reduced in Germany and is caused by overcapacity and reduced scarcity rent.

3.5.1 *Full package scenario with Base emission cap*

A sensitivity was run on the Full package to test the result of using the emissions cap from the Base scenario. Figure 50 shows the impact.

Figure 50 – Carbon prices in the Full Package and the Old Cap sensitivity



If the lower emissions cap (used in the Base scenario) is used in the Full Package scenario, the fundamental CO2 price is zero up to 2030. The sensitivity illustrates the importance of adjusting the emission cap when forcing zero carbon generation into the energy mix, and with increased energy efficiency.

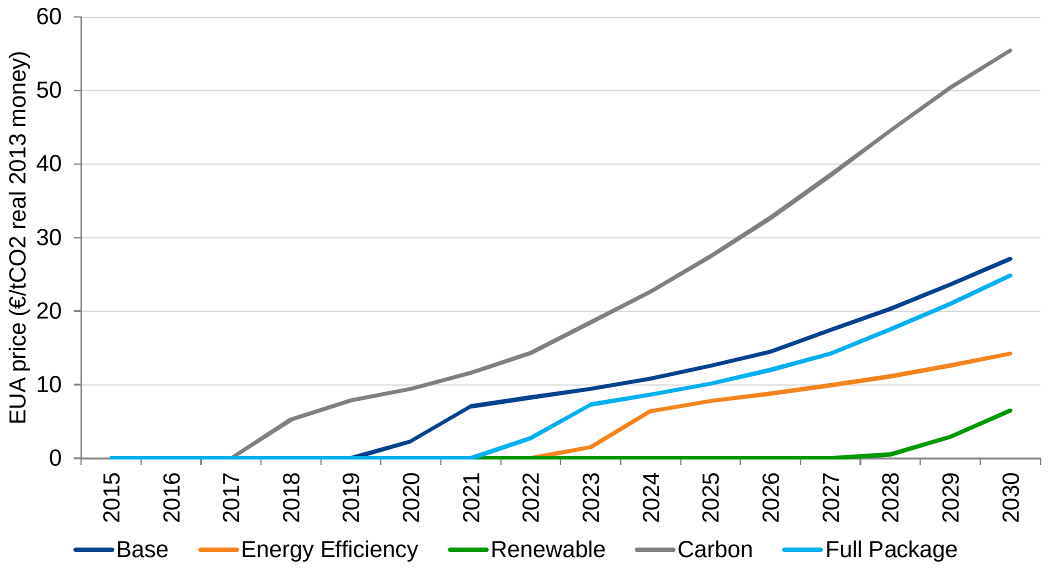
3.6 Cross-scenario comparison

This section gives a brief summary and a comparison of all scenarios investigated in this study. The section mainly focuses on the carbon price, wholesale power prices and the cost of generation for each scenario.

3.6.1 Decarbonisation

Figure 51 shows the cross-scenario comparison of the carbon price.

Figure 51 – Carbon price, all scenarios



There is a large spread in carbon prices between the different scenarios in 2030. The RES scenario gives the lowest carbon price of €6.5/tCO2, and the large drop is mainly caused by the 873TWh of renewables entering the system. The EE scenario also drops the carbon price, though to a smaller extent, as demand is only dropped by 561TWh.

The Carbon scenario gives the highest carbon price of €55/tCO2 in 2030. The significant increase in carbon prices is caused by the tightening of the ETS cap alone, and the effect is reduced by the market reaction which is to shift investments to zero emission capacity.

The FP carbon price gives a carbon price close to the Base scenario. The 873TWh of “free” abatement and zero emission capacity has a significant downward effect on the carbon price. However the tightening of the cap supports the price, and brings it from €0.5tCO2 to €32/tCO2 in 2030.

Table 8 summarises the most important factors influencing the carbon price across the different scenarios.

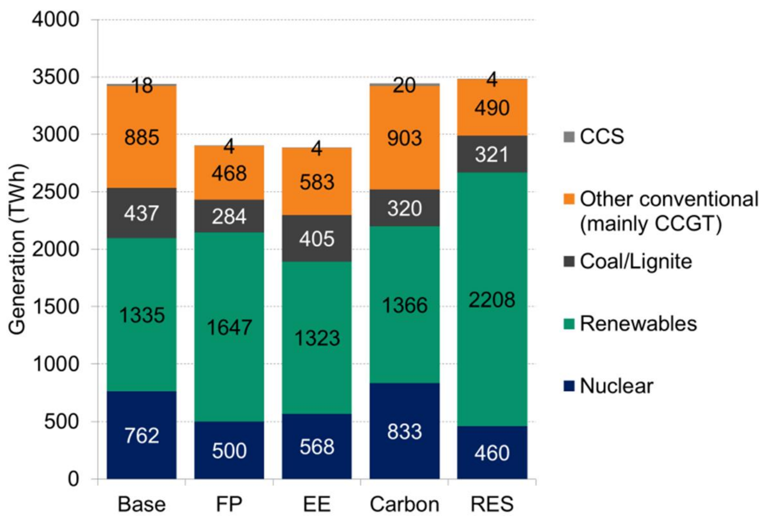
Table 8 – Summary of factors influencing the carbon price

	Free abatement (demand)	Zero emitting generation	ETS emission cap	Effect before market reaction	Market reaction
EE	Reduction in demand relative to Base provide 551TWh of free abatement ↓	No effect —	Annual factor of 1.74%	Sharp decline in carbon prices of 24.3 EUR/tCO2	Investments are reduced and shifts to more carbon intensive technology
RES	No change in demand —	998TWh of renewable generation forced into the system ↓	Annual factor of 1.74%	Sharp decline in carbon prices of 24.2 EUR/tCO2	Investments are reduced and shifts to more carbon intensive technology
Carbon	No change in demand —	No renewable forced into the system	Annual factor of 2.2% ↑	Sharp increase in carbon prices of 61.9 EUR/tCO2	Investments are similar to Base but shifted to less carbon intensive technology
FP	Reduction in demand relative to Base provide 551TWh of free abatement ↓	311TWh of renewable generation forced into the system ↓	Annual factor of 2.2% ↑		Investments are reduced -largest reduction in zero emission capacity

3.6.2 *Generation*

Figure 52 shows generation in 2030 across all scenarios.

Figure 52 – Generation in 2030 in all scenarios



There are large differences between scenarios, for all generation technologies.

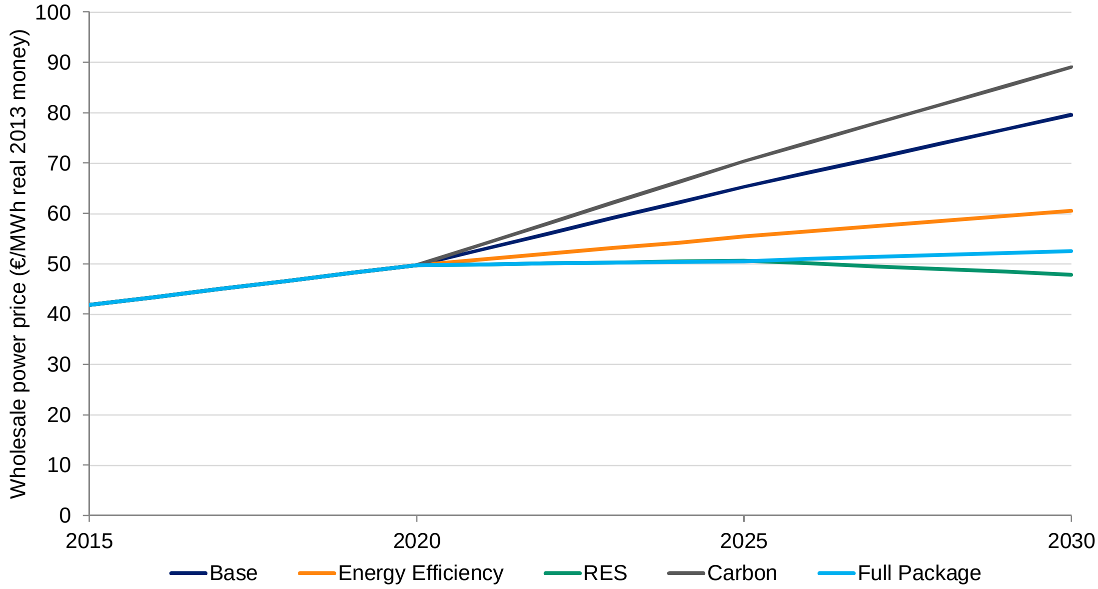
- Nuclear clearly benefits from a higher carbon price, given the fact that it is cheapest zero carbon technology on a Long Run Marginal Cost basis in our assumptions;
- Renewables highest when explicitely supported by a specific target – a high carbon price gives a slightly higher renewable investments (market-based), but this remains limited.

- CCGT and coal/lignite provide the remainder of the generation, as CCS investments remain limited. The balance between CCGT and coal/lignite generation is driven by the CO2 price.

3.6.3 Electricity prices

Figure 53 shows the demand weighted wholesale prices for all scenarios.

Figure 53 – EU average wholesale prices, all scenarios



The Carbon scenario results in the highest wholesale price, and is also closer to the Base relative to the other scenarios. The difference between the Base and Carbon wholesale price is caused by difference in carbon prices.

The RES scenario gives the lowest wholesale price and is €14/MWh below the carbon price in 2030. The RES scenario has the lowest carbon price and the highest level of renewable generation in the system. This has a significant downward effect on the wholesale price.

Table 9 summarises the most important factors contributing to the change in wholesale prices:

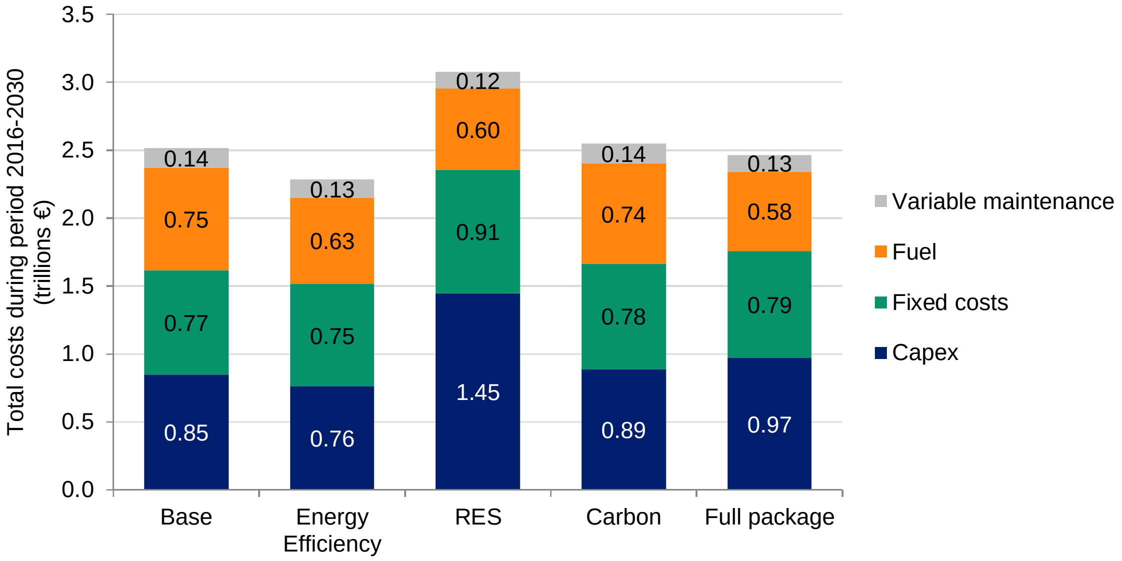
Table 9 – Summary of factors contributing to change in wholesale prices

	Renewable capacity	Demand	Merit order effects	Carbon Price	Scarcity Rent
EE	Same as in Base	551TWh lower in 2030	Overcapacity pushing out power plants with higher SRMC ↓	Lower carbon price reducing SRMC of carbon emitting plants ↓	Decreased peak demand prevent generators from bidding above their SRMC -few or no hours with capacity scarcity ↓
RES	Increase of 998TWh	Same as in Base	Overcapacity caused by increase in renewables capacity -push out plants with high SRMC ↓	Sharp decline in carbon price - reduce SRMC for carbon emitting plants ↓	Increase in renewable capacity creates overcapacity and prevent generators from bidding above their SRMC -few or no hours with capacity scarcity ↓
Carbon	Same as in Base	Same as in Base	No effect —	Sharp increase in carbon price increase the SRMC for carbon emitting plants ↑	No effect —
FP	Increase of 311TWh	551TWh lower in 2030	Overcapacity caused by increase in renewables capacity and lower demand -push out plants with high SRMC ↓	Lower carbon price reducing SRMC of carbon emitting plants ↘	Increase in renewable capacity and decreased peak demand prevent generators from bidding above their SRMC -few or no hours with capacity scarcity ↓

3.6.4 Scenario costs

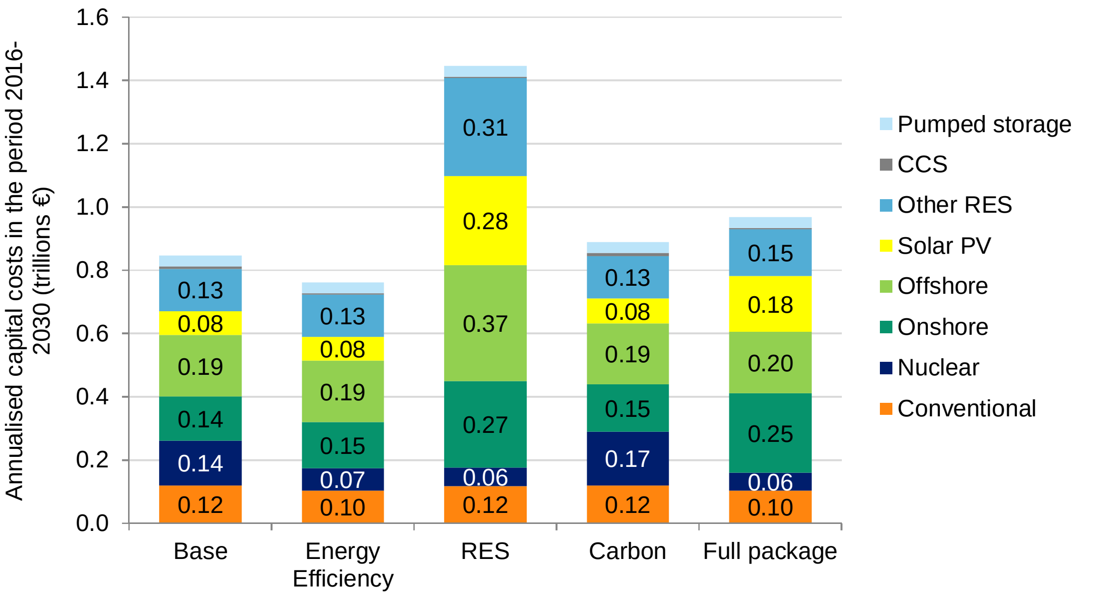
Figure 54 shows the cost of generation in each scenario between 2016 and 2030, split into cost components. Figure 55 shows total annualised capital costs. Costs are not discounted. Transmission costs are not included, but are small, and very similar between scenarios. The annualised cost of a technology is its capital cost spread across its economic lifetime, taking account of its discount rate (technology-specific required rate of return). An investment made in 2025 will have 6 years of annualised costs included in the total i.e. not all of its capital costs would be included. Note that these scenario costs apply to the power sector only.

Figure 54 – Total cost of generation by scenario (excludes cost of carbon and energy efficiency measures)



Note: Not discounted

Figure 55 – Total annualised capital costs by scenario



Note: Not discounted

It is useful to group our comparison into scenarios that achieve the same thing in terms of carbon emissions i.e. those with a looser ETS cap (base, EE, RES) and those with a tighter target (Carbon, Full Package).

The energy efficiency scenario achieves roughly the same carbon emissions as the Base, but at an apparently lower cost (-9%). It is important to note, however, that scenarios with energy efficiency appear cheap since the costs of reducing electricity demand (if any) are not included, but the benefits (lower capex, lower fuel use) are.

The RES scenario achieves the same overall carbon emissions as the Base, but does so at higher cost (+22%). This is mainly driven by higher capex spending to meet RES targets.

The Carbon scenario achieves lower emissions than the Base at only a slightly higher cost (+1%).

The Full Package achieves lower emissions than the Base at a slightly lower cost (-2%). The amount of investment is curbed to a great extent by assumed lower primary energy demand as a result of energy efficiency. RES investments are still significantly higher than in the Base, but these are offset by the benefits of low electricity demand (lower capex, lower fuel use).

It would appear at first glance that the Full Package was the cheapest way to achieve the tighter carbon target. However, the comparison between the Full Package and the Carbon scenario is not on a level playing field. Were the Carbon scenario also to benefit from reduced electricity demand on a similar scale to the delta between the Base and Energy Efficiency scenario, its costs would easily be lower than the Full Package scenario.

There is however a more general consideration to make when looking at these costs: these costs are representative of a perfect market (e.g. efficient and timely investments) and/or a perfect regulation (e.g. perfect renewables support). These cost figures are therefore likely to be the lower bound of actual costs, and real-world inefficiencies in some of these scenarios may actually be more important than the difference between scenarios.

3.6.5 A functioning market?

If demand must be met in all periods then there will be a requirement for some plant to be built that run extremely rarely. For this capacity to be built in an energy-only market, prices would need to rise to extremely high levels in some periods to ensure that the plant that only run in these periods recover all of their capital and fixed costs. The plant also faces significant volume risk – it does not know exactly when it will be called to run. It may therefore demand even higher prices when it does run to compensate for this risk. As RES penetration increases, so does the volume risk for thermal plant, and prices in tight periods have to rise to ever higher levels to compensate.

In this study we have limited the amount that generators can bid over and above their short term marginal costs to levels that have been observed historically. In the Base this poses few problems, and the price signals in energy-only markets are potentially sufficient to bring forward the investment required to meet demand. This however assumes that all stakeholders leave market prices to rise to levels consistent with new entry, in the form of price spikes during periods of tightness.

In the Full Package scenario, however, this is not the case. Some energy-only markets fail to bring forward the required investment. For example, the Full package delays the need for new investment until 2037 in Poland. However, even when wholesale prices are allowed to rise above short run marginal costs to the extent observed historically, they are not high enough to incentivise new build. If this capacity is not forthcoming then Poland experiences loss of load. Even more importantly, power prices and margins do not support the recovery of annual fixed costs for the existing production park, which could lead to wide-spread bankruptcy and sub-optimal outcomes like for example an important cycle of plant closure followed by a need for investment in new plants.

There are a number of solutions to this issue:

1. **Allow prices to rise further**. Price volatility any higher than historic levels is deemed by many not to be an acceptable solution
2. **Allow loss of load**. Most economists would argue that this is the correct solution – a select few consumers would be more willing to shed load for a small number of periods per year, rather than pay for the capacity to cover them
3. **Develop and invest in demand side response** (flexible demand). DSR has the potential shift load from tight periods to looser periods. The cost of doing so may be lower than the cost of building new capacity, so prices would not need to rise to such high levels to incentivise investment.
4. **Remunerate capacity outside the energy-only market**. This could take the form of capacity payments or more innovative and adaptable products such as energy options. An alternative, regular revenue stream outside the energy-only market reduces the amount of money that must be recovered from the energy-only market to cover fixed and capital costs. It also reduces volume risk by providing a regular payment, regardless of whether the plant runs. The risk premium for new capacity is therefore reduced.
5. **Build strategic reserve**. This is peaking capacity that is only permitted to bid in at a fixed €/MWh value. It does not recover its costs in the energy-only market, but is 'made whole' by out-of-market government subsidies

In our modelling we have assumed that option 4 occurs. In Poland, the 'missing money' from the energy-only market for a variety of technology candidates is bid into the capacity market. CCGT has the least missing money at ~€80/kW/year and is the technology that is built. The capacity market clearing price is therefore ~€80/kW.

4. CONCLUSIONS

Pöyry has conducted a detailed quantitative analysis over the period from today to 2030, using four detailed in-house Pöyry models: BID3 modelling the power market over the whole of Europe at an hourly resolution, a carbon model covering the entire EU ETS, a European renewable energy model covering electricity, heat and transport and finally an econometric model of electricity demand in Europe. These four models have been used in order to produce fully internally consistent scenarios taking into account the interaction between the different packages and the potential market reactions on investments. In this study, the different elements of the 2030 package are implemented in a harmonised and cost-effective way.

Pöyry concludes that the 2030 climate package is likely to lead to a very significant transformation of the electricity system, with far reaching consequences all over Europe. Pöyry finds that the carbon price may not vary significantly as a result of the 2030 package, but that wholesale power prices could decrease by more than 30% by 2030 under the combined pressure of renewable and energy efficiency objectives. The continuation of low power prices and low profit margins is likely to result in a continued period of difficulties for utilities, and the problem of 'missing money' will need to be addressed both in order to maintain existing plants online and to build new ones where necessary.

Pöyry's analysis suggests that adopting either the renewables target or the energy efficiency target in isolation may lead to unintended outcomes due to their negative impact on the carbon price. In particular, an unrestricted market outcome could see coal plants being built instead of low carbon technologies, therefore 'locking' Europe away from a longer term decarbonisation path. On the contrary, the tightening of the carbon market in isolation would deliver carbon emission reductions by incentivising lower carbon generation (e.g. CCGTs) and investments (in particular nuclear), at the expense of a higher wholesale electricity price.

Future energy markets are full of challenges and opportunities for Norwegian consumers and producers. The way that these climate objectives are implemented have the potential be game-changers for the whole industry, and careful qualitative and quantitative analysis should be at the heart of decision processes for all stakeholders.

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ANNEX A –MODELS

A.1 BID3 –power market model

BID3 is Pöyry's power market model, used to model the dispatch of all generation on the European network. We simulate all 8760 hours per year, with multiple historical weather patterns, generating hourly wholesale prices for each country for each future year and dispatch patterns and revenues for each plant in Europe.

We have developed BID3 out of our previous power market models: *BID 2.4* which has sophisticated treatment of hydro dispatch, using Stochastic Dynamic Programing to calculate the option value of stored water; and *Zephyr*, which has underpinned our ground-breaking studies quantifying the impacts of intermittency in European electricity markets and the role flexibility could play in meeting the challenges of intermittent generation. BID3 is highly flexible to use and incorporates the best aspects of our previous models.

BID3 is extensively used;

- It is the modelling platform used for Pöyry's *Electricity Market Quarterly Analysis* reports, giving European power price projections used by major banks, utilities, governments and developers;
- We use BID3 for bespoke projects for a wide range of clients; and
- BID3 is available to purchase, and is used by Energinet, Fingrid, Norsk Hydro, NVE, Statnett, Transnet BW, and Svenska Krafnät.

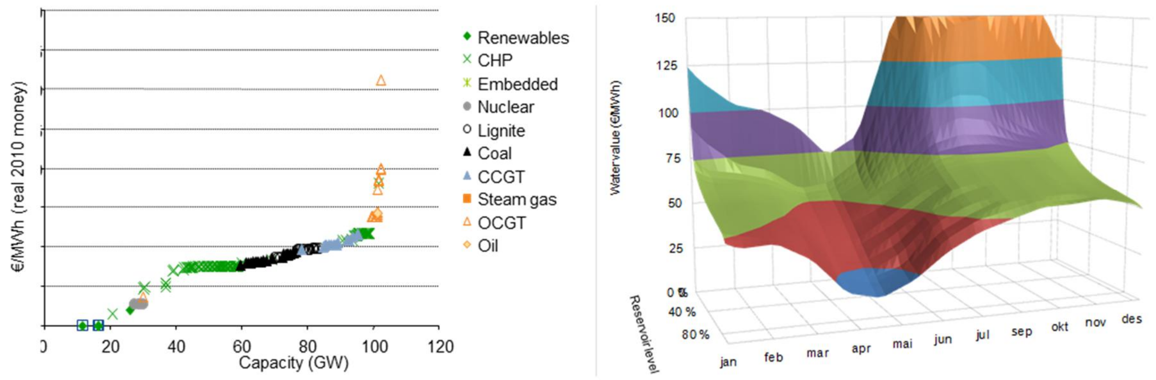
Modelling methodology

BID3 is an economic dispatch model based around optimisation. The model balances demand and supply on an hourly basis by minimising the variable cost of electricity generation. The result of this optimisation is an hourly dispatch schedule for all power plant and interconnectors on the system. At the high level, this is equivalent to modelling the market by the intersection between a supply curve and a demand curve for each hour.

- **Dispatch of thermal plant.** All plants are assumed to bid cost reflectively and plants are dispatched on a merit order basis – i.e. plants with lower short-run variable costs are dispatched ahead of plant with higher short-run variable costs. This reflects a fully competitive market and leads to a least-cost solution. Costs associated with starts and part-loading are included in the optimisation. The model also takes account of all the major plant dynamics, including minimum stable generation, minimum on-times and minimum off-times. Figure 56 shows and example merit order curve for thermal plant.
- **Dispatch of hydro plant.** Reservoir hydro plants can be dispatched in two ways:
  - a simple perfect foresight methodology, where each reservoir has a one year of foresight of its natural inflow and the seasonal power price level, and is able to fix the seasonality of its operation in an optimal way; or
  - the water value method, where the option value of stored water is calculated using Stochastic Dynamic Programming. This results in a water value curve where the option value of a stored MWh is a function of the filling level of the reservoir, the filling level of competing reservoirs, and the time of year. Figure 56 shows an example water value curve.

- **Interconnector flows.** Interconnectors are optimally utilised – this is equivalent to a market coupling arrangement.

Figure 56 – Thermal plant merit-order, and water value curve



Power price

The model produces a power price for each hour and for each zone (which may be smaller than one country, for example there are different price areas within Norway). The hourly power price is composed of two components:

- **Short-run marginal cost.** The SRMC is the extra cost of one additional unit of power consumption. It is the minimum price at which all operating plant are recovering their variable costs. Since the optimisation includes start-up and part-load costs all plant will fully cover their variable costs, including fuel, start-up, and part-loading costs.
- **Scarcity rent.** A scarcity rent is included in the market price – we assume power prices are able to rise above the short-run marginal cost at times when the capacity margin is tight. In each hour the scarcity rent is determined by the capacity margin in each market. It is needed to ensure that the plants required to maintain system security are able to recover all of their fixed and capital costs from the market

Input data

Pöyry's power market modelling is based on Pöyry's plant-by-plant database of the European power market. The database is updated each quarter by Pöyry's country experts as part of our *Electricity Market Quarterly Analysis*. As part of the same process we review our interconnection data, fuel prices, and demand projections.

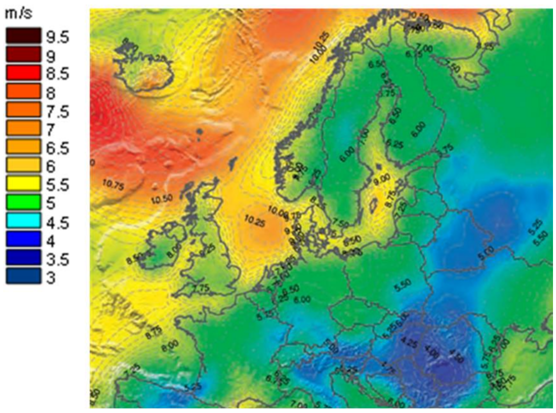
- **Demand.** Annual demand projections are based on TSO forecasts and our own analysis. For the within year profile of demand we use historical demand profiles – for each future year that is modelled we use demand profiles from a range of historical years.
- **Intermittent generation.** We use historical wind speed data and solar radiation data as raw inputs. We use consistent historical weather and demand profiles (i.e. both from the same historical year). This means we capture any correlations between weather and demand, and can also model a variety of conditions – for example a particularly windy year, or a cold, high demand, low wind period.

- – Our wind data is based on reanalysis of satellite observations and weather modelling[25], and gives hourly wind speeds at grid points on a 20km grid across Europe, at hub height. Figure 57 shows average wind speeds based on this data. Hourly wind speed is converted to hourly wind generation based on wind capacity locations and using appropriate aggregated power curves.
- – The solar radiation data[26] is converted to solar generation profiles based on capacity distributions across each country. Figure 57 shows average solar radiation based on this data.

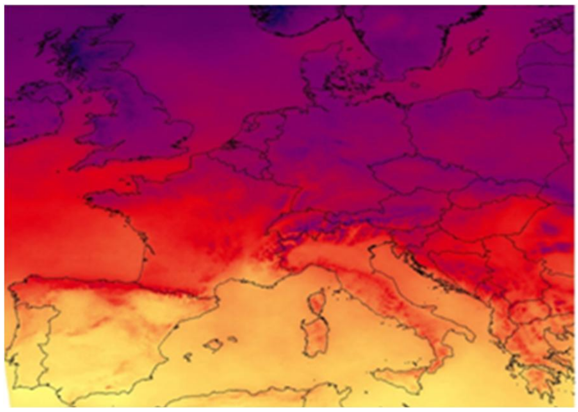
- **Fuel prices.** Pöyry has a full suite of energy market models covering coal, gas, oil, carbon, and biomass. These are used in conjunction with BID3 to produce input fuel prices consistent with the scenarios developed.

Figure 57 – Average wind speeds and solar irradiation in Europe

Average wind speeds in Europe



Average solar irradiation in Europe



Economic development (demand and renewable investments) Model results

BID3 provides a comprehensive range of results, from detailed hourly system dispatch and pricing information, to high level metrics such as total system cost and economic surplus. As selection of model results is show below in Figure 58 and Figure 59.

25 Provided by the company Anemos, http://www.anemos.de

26 Data from Transvalor, http://www.soda-is.com

Figure 58 – Hourly dispatch and related metrics

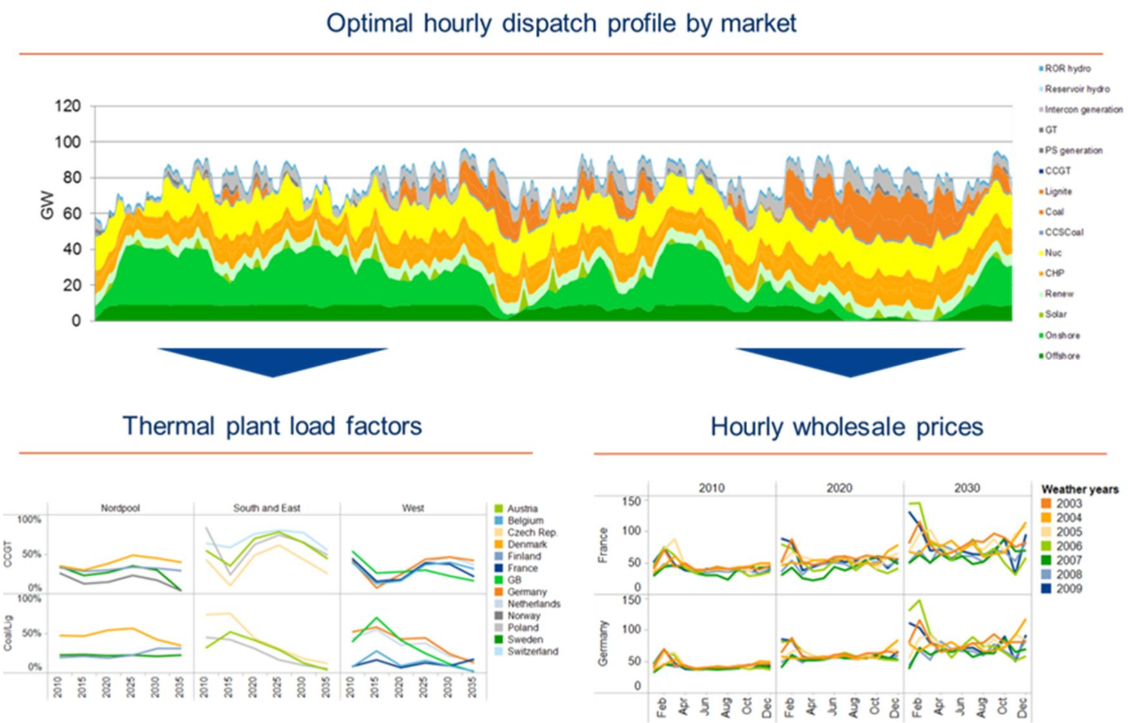
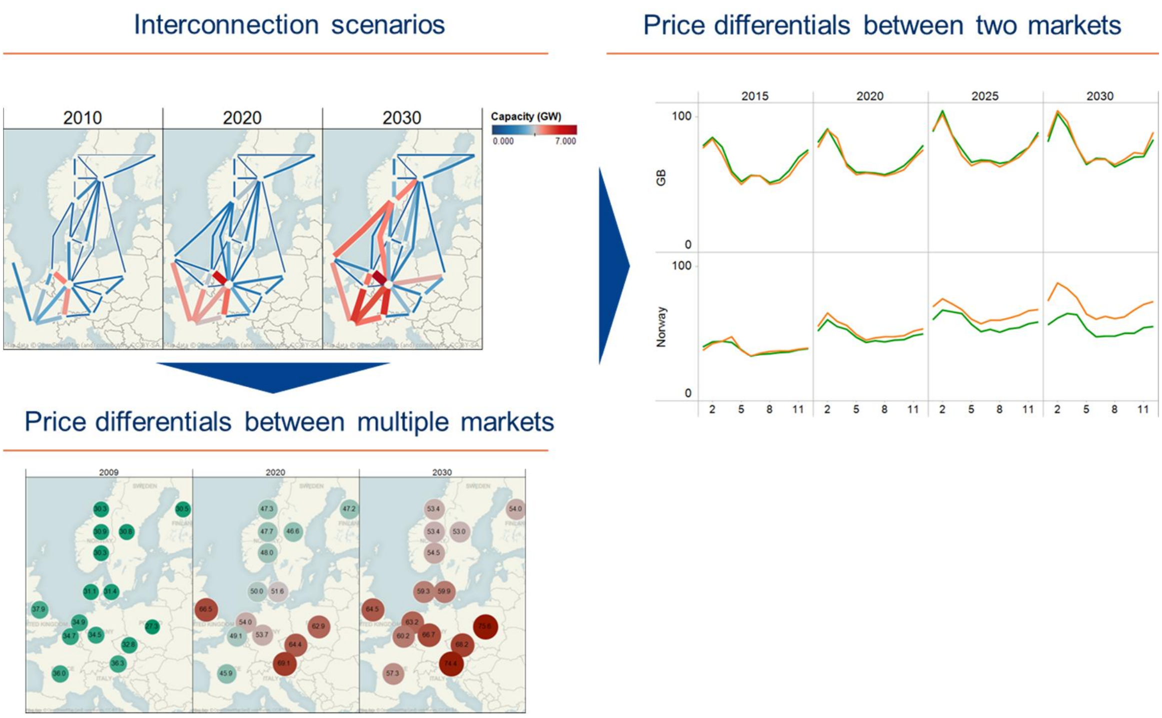


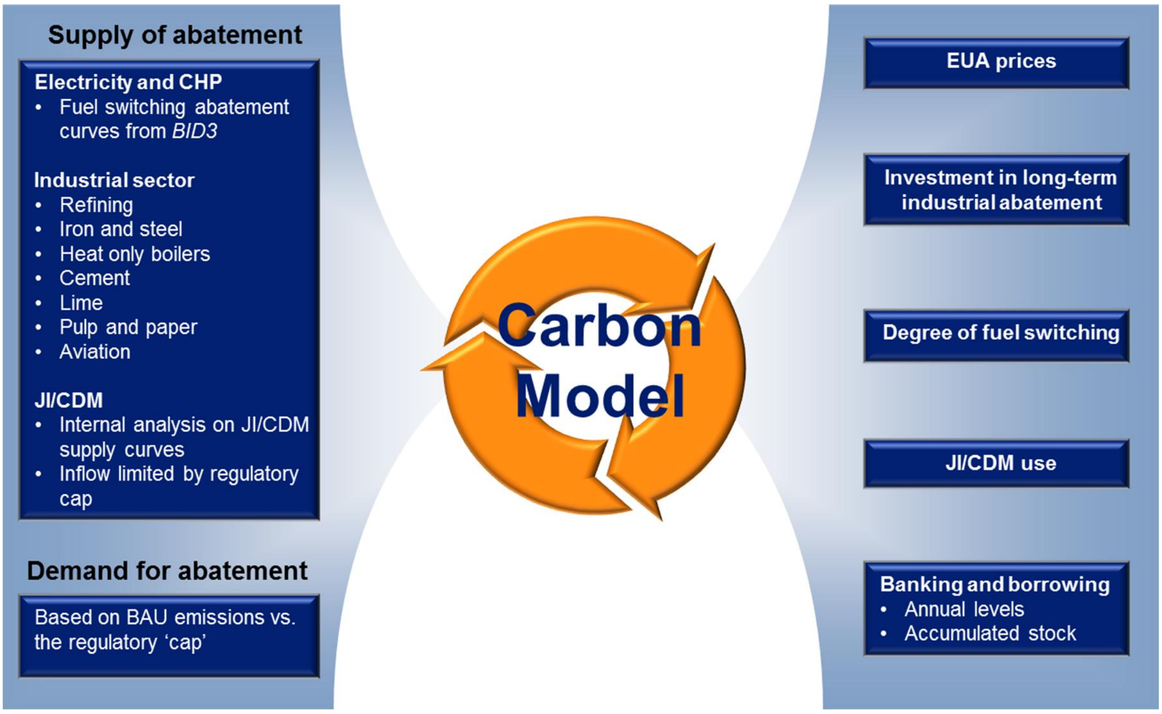
Figure 59 – Interconnector value assessment



A.2 Pöyry Carbon Model

Pöyry's carbon model is used to derive projections of European Union Allowance (EUA) prices that are consistent with the fuel prices and electricity demand projections in each of our electricity price scenarios. The structure of the model is shown in Figure 60. Prices are set by minimising the overall cost of meeting the EU ETS cap on emissions. Demand for allowances is driven by the difference between the baseline level of emissions from the EU ETS sectors if the carbon price was zero (known as the business as usual, or BAU emissions level) and the cap on emissions in the EU ETS. As long as the BAU level is above the cap some EU ETS participants must restrict their emissions thereby creating a market for emissions abatement. The supply of abatement comes from switching away from carbon intensive fuels in the power sector, non-power sector abatement and the import of Kyoto credits.

Figure 60 – Structure of the carbon model



Demand for abatement

Demand for abatement is calculated as the difference between a business as usual baseline (expected emissions with a zero price of carbon) and the overall cap on emissions.

- Baseline: The baseline comprises emissions from both power generation and industry.
  - Baseline power generation emissions are calculated by running our BID3 model with a carbon price of zero. The model therefore fully incorporates our assumptions on future European generating capacity, including the growth of low carbon forms of generation, which we assume are driven by European and national renewable targets, and their associated subsidy schemes.
  - Emissions from the industrial sectors are calculated based on Pöyry's assessment of industry sector growth rates. These assumptions are linked to

historical and short, medium and long term European projections, as well as Industrial Production Indexes (IPI) for the corresponding sectors.

- Emissions Cap:
  - to 2020: The overall cap on carbon emissions is set out in the EU ETS Directive and declines by 1.74% per year from 2013. This is consistent with the target to reduce GHG emissions in the EU ETS by 21% by 2020
  - beyond 2020: a 'Business as Usual' case can continue the path of decarbonisation of 1.74% per year, whilst modelling the 2030 package would involve a 2.2% after 2020

Supply of emission reductions

The carbon price is determined by the marginal cost of the abatement source required to meet the demand for carbon credits. There are three sources of emissions reduction:

- Fuel switching in the power sector: Power sector abatement curves are derived from our BID3 model using the fuel prices in the relevant electricity price scenario. By iterating between our electricity, carbon and gas models we are able to get an internally consistent view of the abatement potential from fuel switching in the power sector.
- Abatement from the industrial sectors covered by the EU ETS: Abatement curves for the industrial sectors are based on sector specific analysis of technology switching, efficiency gains and fuel switching potential.
- Imports of CDM and JI credits: The EU ETS Directive stipulates that only 50% of the abatement needed between 2005 and 2020 can come from the use of offset credits, with the overall volume limit estimated to be ~1.6 billion tCO_2. We assume the supply will be greater than the limit imposed, and that these credits will be submitted for compliance at the maximum level allowed within the rules of the scheme in all scenarios. Beyond 2020 the policy landscape is still uncertain and we use a range of approaches depending on the scenario considered.

These three sources of abatement have differing cost structures and combine to create a supply curve of abatement in each modelled year which differs by scenario.

European CO_2 price formation

In a simplistic model, a carbon price for a year in isolation could be determined by the intersection of our abatement supply and demand curves in that year. However, the ability of market participants to bank credits between years makes this methodology incomplete. If market participants foresee a much tighter market in future, credits would be banked, bringing prices up in the short term and down in the longer term.

The Pöyry Carbon Model uses a linear optimisation to minimise the cost of meeting demand for abatement over a number of years simultaneously. The number of years over which the model calculates this is referred to as the 'optimisation window'. The carbon price is determined by the cost of the marginal abatement source required to meet the total demand for all years in the optimisation window. As we move forward through our modelled period, the optimisation window moves forward as well. For example, in 2020 the carbon price is determined by an optimisation that covers the period from 2020 to 2035.

At present the EU ETS is expected to be long on credits for a number of years. Prices have not fallen to zero for two main reasons (both of which are modelled by the Pöyry Carbon Model):

- Market participants may see a tighter market in the longer term and are banking credits now to minimise future costs (which we model using a rolling 'optimisation window' approach); and
- Market participants believe there is some possibility of the EU reducing the supply of allowances into the market in the future. To capture the value that this uncertainty brings to the carbon price, the Pöyry Carbon Model is able to optimise under a number of possible future caps, with associated probabilities. The use of this feature varies by scenario.

The Market Stability Reserve

Alongside its framework for climate and energy policies up to 2030, the commission also submitted a proposal for a market stability reserve in the EU ETS.

The aim of the reserve is to provide an automatic mechanism to adjust the supply of permits depending on the demand for permits. In principle, at times of economic recession, when the demand to emit is relatively low, supply of permits would be withdrawn from the market into a reserve. Conversely, when demand for permits is relatively high, permits in the reserve would be re-injected into the market.

The mechanism's design is rule-based in order to avoid government interference and reduce regulatory uncertainty. In the current proposal the rules for injection / withdrawal are based on the market surplus, defined as:

Surplus = [Allowances allocated since 2008] + [International credits used in the ETS since 2008] – [Verified emissions since 2008]

On 15th May of each year, the Commission publishes the surplus for the previous year. If the surplus in the previous year is greater than 833Mt then the following year 12% of the surplus is withheld from the market in the reserve. If it is less than 400Mt then 100Mt is returned from the reserve to the market.

In the absence of any market stability reserve, the bankability of credits between years makes the determination of the least cost abatement solution an inter-temporal problem. Players can choose to abate more than necessary in the short term in order to bank credits for use in the long term, where abatement costs may be higher. Similarly, a purely financial player could buy and bank permits in the short term and sell them in the longer term when prices are higher. The timeframe over which the market looks when making these decisions varies by player, but many commentators argue that the market is currently rather myopic. Our market modelling suggests that, left unattended, such short-sightedness leads to very low prices in the short term but, once the market tightens very high prices. Arguably the market stability reserve can act as a more long-sighted overseer to the market, 'artificially' banking allowances now and releasing them later when the market is tight.

In Pöyry's modelling of EU ETS market fundamentals, we use a market foresight window of 20 years for the following reasons: (a) many low-carbon investments are made with economic lifetimes of 15 or 20 years. For example, investment in an arc furnace or low-carbon power plant is not based on the expected carbon price over the next 5 years but the next 15 or 20. (b) the overall cost of abatement is significantly lower with a longer-sighted investment window. It is therefore likely that either government (seeking to reduce costs for consumers) or financial players (seeking arbitrage opportunities between low short-term and high long-term prices) will take a longer term view than today's. Therefore, while the exact details of the market stability reserve are not explicitly modelled, we effectively model a 'perfect' market stability reserve. Our prices therefore represent the value of carbon in an efficient, long-sighted market.

A.3 Pöyry Eureno Model

Pöyry Management Consulting's pan-European renewables model, *Eureno*, was developed to analyse the impacts of the EU's 2020 renewables targets on the twenty seven member states. It uses databases that hold data on the realisable potential of each type of renewable technology (in the electricity and heat sectors) for each country, the cost of those resources and supply chain constraints.

The model has been extended to produce a pan-European supply curve of renewable technologies for the period to 2030, to project the volume of generation by each renewable technology in each country, allowing identification of market size in the coming decades. It also includes up to date information on the National Renewable Energy Action Plans to ensure that existing renewable build is included in the modelling. Its flexibility allows to be honed to client's specific requirements, to run multiple scenarios and to undertake extensive sensitivity analysis. It has been used in a number of renewable strategy projections to provide first-pass assessments of market attractiveness for investors.

The model can be used to analyse the economic costs of meeting the European renewables targets under different scenarios, and to assess the resulting carbon abatement.

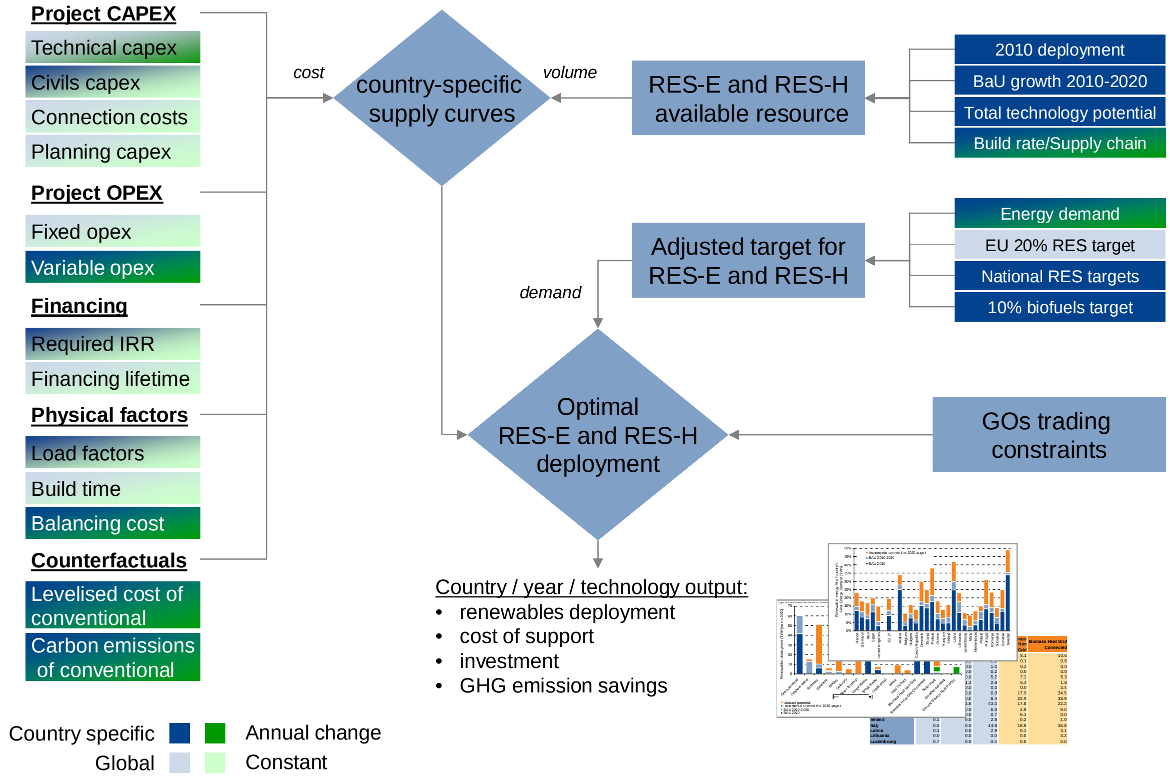
Through the model we are able to assess:

- the cost of the policy;
- different burden sharing scenarios;
- different trading scenarios;
- sensitivity to key parameters;
- fundamental drivers of relative renewables costs;
- the potential price of a 'European Green Certificate', and
- achievable potential.

Approach to the modelling

The model is designed to build a supply curve from cost and volume information, focussing on the incremental effort to meet the 2020 target, over and above business as usual deployment (e.g. what already exists and what will be deployed under current policies). An overview of the model structure is presented in Figure 61, below:

Figure 61 – Detailed modelling methodology



Note: this figure corresponds to the modelling of the 2020 target – the model has subsequently been developed to model the 2030 timeframe

A.4 Demand model

Our projections for electricity demand are based on a new methodology developed in Pöyry. The underlying demand growth is estimated by an econometric model: the model assumes a long-term relationship between electricity demand and GDP, and deviation from the long-term relationship is captured by the short-term dynamics. Thus, growth in power demand in a certain country in year t is related to growth in GDP, as well as the gap between the variables in the previous period, as shown in the following expression:

$$\Delta\, power\ demand_t = \alpha + \beta * \Delta\, gdp_t - \gamma * (power\ demand_{t-1} - \delta * gdp_{t-1}) + \ \varepsilon_t$$

Where;

Δ *power demand*$_t$ *= Growth in power demand from year t-1*

Δ *gdp*$_t$ *= Growth in GDP from year t-1*

Power demand$_{t-1}$ *= Power demand in year t-1*

gdp$_{t-1}$ *= GDP in year t-1*

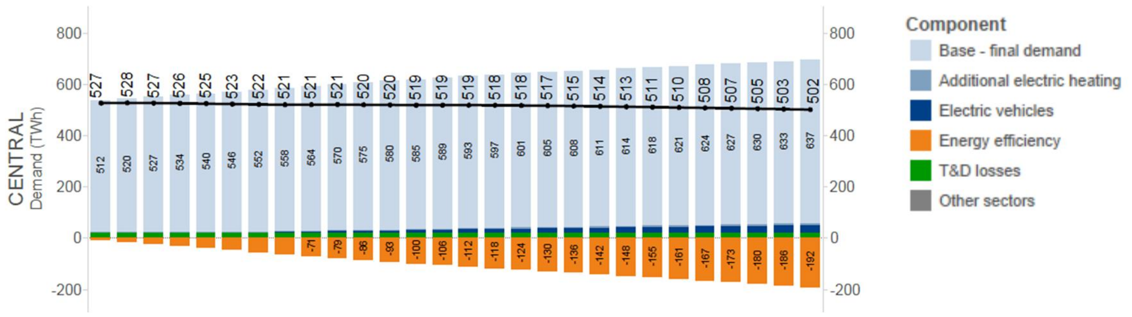
The base demand for each future year is calculated by using annual Gross Domestic Product (GDP) growth assumptions. For Central scenario we have assumed International Monetary Fund (IMF) projections from 2013-2018, and extrapolation later on.

In addition to the underlying demand development due to economic growth/recession, the demand model also captures the impact of energy efficiency and shift of energy demand from transport and heat sectors into electricity. This results in an adjustment (i.e. reduction for energy efficiency and increase due to electrification of heat and transport sectors) in the base demand levels.

- Energy efficiency: we have assumed a certain reduction in energy demand due to energy, based on national information when available.
- Electric vehicles (EV): Projections of the total stock of vehicles are adjusted according to population growth. The penetration of EV assumed is increased from existing levels to a certain share of total vehicles later on.
- Electricity share of heat demand: we assume a certain increase in the electricity share of heat demand from today's level onwards. The assumed increase is based on the business-as-usual scenario of the EU 2050 Heat roadmap where heating is assumed to cover most of the increased heat demand.
- Other sectors: in addition, where relevant, we have added some specific new sectors of demand that can't be captured by past correlation between GDP and Demand levels. For example, the electrification of the extraction of Oil and Gas in Norway is added on top of the other factors.

Figure 62 shows an example result for Germany: Base demand increases from 512TWh/year to 637TWh/year, but electric vehicles and energy efficiency combined bring the total demand from 527TWh/year to 502TWh/year. Changing the level of energy efficiency requirements for all countries would allow us to model the possible effect of the 2030 package.

Figure 62 – Example result (Germany), 2013-2040



ANNEX B – COST OF NEW CAPACITY

Table 10 shows the capex (€/kW) and fixed opex (€/kW/year) for thermal and renewable technologies in year 2015-2030.

Table 10 Cost of new investments (2015-2030)

	Capex	Opex	Capex	Opex	Capex	Opex	Capex	Opex	Hurdle rate	Financial lifetime (years)
	2015		2020		2025		2030			
Biogas	4776.3	311.2	4619.5	305.7	4617.1	305.7	4617.1	305.7	10 %	15
Biomass	1880.9	595.3	1830.1	595.3	1779.4	595.3	1731.3	595.3	12 %	15
Biowaste	4337.7	284.6	4248.6	279.6	4179.2	279.6	4116.3	279.6	10 %	15
CCGT	790.0	32.0	790.0	32.0	790.0	32.0	790.0	32.0	9 %	20
Coal	1650.0	56.6	1650.0	56.6	1650.0	56.6	1650.0	56.6	11 %	20
Offshore Wind	3020.7	36.8	2888.0	36.8	2760.6	36.8	2639.5	36.8	12 %	20
Onshore Wind	1259.0	36.8	1230.3	36.8	1200.5	36.8	1172.7	36.8	9 %	15
Geothermal	550.0	27.3	550.0	27.3	550.0	27.3	550.0	27.3	9 %	20
Hydro	2698.8	55.8	2698.8	54.8	2698.8	54.8	2698.8	54.8	9 %	15
Nuclear	4000.0	70.0	4000.0	70.0	4000.0	70.0	4000.0	70.0	10 %	25
OCGT	513.0	30.0	513.0	30.0	513.0	30.0	513.0	30.0	10 %	20
Solar PV	1000.0	26.3	789.5	15.8	710.6	15.8	631.6	15.8	10 %	20

Cost input for thermal investments is the same across Europe, whereas renewable costs are from Great Britain and vary between different European countries.

QUALITY AND DOCUMENT CONTROL

Quality control		Report's unique identifier: **2014/012**
Role	Name	Date
Author(s):	Alan Whitaker, Cathrine Torvestad, Michel Martin	
Approved by:	Michel Martin	December 2014

Document control			
Version no.	Unique id.	Principal changes	Date
v3_0	2014/012		December 2014

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