JRC REFERENCE REPORTS

Future Fossil Fuel Electricity Generation in Europe: Options and Consequences

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2009

JRC EUROPEAN COMMISSION

Institute for Energy

Report EUR 23080 EN

The mission of the JRC-IE is to provide support to Community policies related to both nuclear and non-nuclear energy in order to ensure sustainable, secure and efficient energy production, distribution and use.

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Joint Research Centre
Institute for Energy

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This publication is a Reference Report by the Joint Research Centre of the European Commission.

JRC 42187

EUR 23080 EN
ISBN 978-92-79-08176-7
ISSN 1018-5593
DOI 10.2790/38744

Luxembourg: Office for Official Publications of the European Communities

Printed in the Netherlands

Assessment of Energy Technologies and Systems (ASSETS)

The objective of ASSETS is to provide the scientific and technical reference information needed to identify and promote the strategies that the EU can pursue to accelerate the development and deployment of advanced energy technologies and systems that can help Europe meet the goals of its energy and energy research policies.

Contents

Executive Summary

Electricity demand in the European Union (EU) is rising, and there are no indications that this demand will be curbed significantly in the short and medium term, despite the energy savings and improved efficiency measures that have been implemented. At the same time, the electricity generation infrastructure is aging and a large number of power plants are scheduled for retirement. Unless new electricity generation capacity is developed to fill the emerging gap between electricity demand and supply, the European power generation sector will be under severe strain in the coming years, with negative consequences for the European economy and the standard of living of Europe's citizens.

Capacity planning for new electricity generation facilities has traditionally been carried out on the basis of economic criteria, with a focus on the minimisation of both the capital and operational costs. However, the choice of technologies for these new facilities not only affects the magnitude of the required capital investment, but also impacts greatly on the energy policy goals of the EU, namely reducing carbon dioxide (CO_2) emissions, maintaining a secure energy supply and enhancing the competitiveness of European industry.

Transforming the challenge of renewing and expanding the electricity generation capacity into an opportunity for improving efficiency and reducing CO_2 emissions in the power generation sector requires a carefully planned strategy, since choices for the future technology and fuel mix will bind the sector in the long term, influencing the path to sustainability, competitiveness and energy security.

Concerning the future fuel mix, energy outlooks tend to agree that the contribution of renewable energy sources will increase, but will not dominate the electricity generation sector before 2030, while the nuclear power plant capacity will either shrink or remain unchanged. Therefore, fossil fuel power plants will remain the backbone of the European electricity-generating sector until at least 2030. Continuing reliance on fossil fuels necessitates the deployment of power plant technologies with the minimal possible carbon footprint, such as advanced power plants that capture most of the CO_2 generated. According to the European industry, such plants could be commercially deployed on a large scale as of 2020, while first-of-a-kind plants could be operational around 2015.

Nevertheless, power plants with carbon capture capabilities will be more expensive to build and operate than similar plants that do not capture CO_2. Hence, such technologies would not be deployed in the absence of financial incentives, if the sole criterion for selecting a technology for a power plant were that of the lowest costs. Moreover, power plants with carbon capture facilities are less efficient than conventional power plants, so their deployment could lead to an increase in fossil fuel consumption with impacts on the security of supply. Furthermore, it is suggested that the deployment of such power plants could result in an increase in the cost of electricity with concomitant effects on the competitiveness of the European economy.

These statements highlight the fact that there may not be a unique solution, i.e. an optimal technology mix that could simultaneously satisfy all the objectives of the European energy strategy. A good understanding of the mechanisms that influence the evolution of the power generation sector is therefore necessary to evaluate the different trade-offs in support of policy decisions.

This study attempts to identify the critical factors that influence the development of the fossil-fuel-fired power generation sector in Europe up to 2030 and describe the possible scenarios for its evolution. Through the application of least-cost expansion planning approaches, the technology and fuel mix of fossil fuel power plant portfolios emerging from 24 techno-economic scenarios are described. The different scenarios present alternative views for the role of non-fossil fuel (nuclear and renewable) power generation, the development of the world fuel and carbon markets and the carbon capture power-generating technologies.

More specifically, there are *business-as-usual (BAU)* and *policy* scenarios for the development of nuclear and renewable capacity with moderate and high projections for the penetration of non-fossil power generation. The study considers three alternative cases for the development of the international prices of fossil fuels: '*a high fuel price case*', '*a medium fuel price case*' and 'a *low fuel price case*'. It also considers two alternative cases for the evolution of the price of CO_2 ('*low CO_2 price case*' and '*high CO_2 price case*'). Two different cases are examined concerning the penetration of carbon capture and storage (CCS) in the power sector: '*the CCS case*', that assumes that power plants with this technology are commercially ready to contribute to the power generation system from 2020 onwards;

and '*the no-CCS case*', that does not consider the deployment of power plants that capture CO_2 in the European energy system before 2030.

A key assumption of the study is that the EU is treated as one control area with a single electricity market and without any electricity transmission constraints. Furthermore, it is assumed that there are no energy resource supply constraints, or restrictions in the deployment of a technology once commercialised. This implies that a legal and regulatory framework for CCS is in place and adequate CO_2 storage capacity has become available. Finally, it is assumed that new capacity is built only when a capacity gap exists even if the existing capacity does not represent the best technological solution in economic terms. Whilst this approach is very useful in order to demonstrate the broad sensitivities of investments to various background assumptions, it should not be viewed as a capacity planning exercise as the above assumptions deviate from the reality of a liberalised electricity market.

The study estimates the need for new fossil fuel capacity and identifies the optimal power plant mix for all combinations of the cases mentioned above. The impacts of the resulting portfolios on European energy policy objectives are assessed using the capital investment for the construction of the capacity needed, fuel consumption, fuel mix diversity, CO_2 emissions, and the average production cost of electricity from the fossil-fuelled power plant fleet as indicators.

In a business-as-usual case where fossil fuels maintain their current share in power generation over the next 25 years, the forecasted capacity requirements are estimated at 700 GW (taking into account peak load projections in the period to 2030 and a 20% reserve margin). Hence, 300 GW of additional capacity compared to the 2005 level is needed to meet the growing electricity demand in view of the modest penetration of non-fossil fuel power generation technologies that has been assumed. Moreover, the current operating capacity of 400 GW is expected to decline to 65 GW in 2030 as existing power plants are gradually retired[1]; widening the gap between the required capacity and the operational capacity of power plants built before 2005.

The study finds that between 510 GW and 635 GW of new fossil fuel power plant capacity will need to be constructed in the EU by 2030 to meet the rising demand for electricity and to replace retiring power plants. The low estimate for capacity requirements corresponds to a scenario with increased contributions from non-fossil sources (policy case), while a BAU assumption results in higher needs for new capacity. The capital requirements for the construction of the new fossil fuel capacity range between EUR 250 billion and EUR 630 billion[2] depending on the penetration of non-fossil technologies as well as the technology mix chosen for the new capacity.

If carbon capture technology is not commercialised before 2030, the mix of conventional power plant technologies deployed will be primarily dictated by the cost of CO_2 emissions: low CO_2 prices will promote the use of pulverised fuel coal plants and high CO_2 prices will make natural gas combined cycle plants the technology of choice. Fuel prices will have a secondary role in the technology mix; although they will not have an influence on the type of technology deployed under high carbon prices, they will influence the relative share of pulverised fuel coal and natural gas combined cycle plants under low carbon prices, where higher fuel prices will favour coal technology due to reduced fuel costs.

Even if carbon capture technology is commercialised within the time span of the study, its large scale deployment depends on the CO_2 price reaching a minimum value, which is in the range of EUR 34/t to EUR 55/t in 2020, depending on fuel prices. If this threshold value is exceeded, power plants with carbon capture will become the competitive technology of choice, and assuming that deployment starts in 2020, up to 190 GW to 280 GW of new capacity with CCS could be built by 2030, which corresponds to 33% to 40% of the total installed capacity at the time. These power plants will capture between two and seven billion tonnes of CO_2 until 2030.

The technology and fuel of power generation with CCS is dictated by the assumptions made about the fuel market: Integrated Gasification Combined Cycle (IGCC) plants with pre-combustion capture will be deployed under medium and high fuel prices, while under low fuel prices natural gas combined cycle plants with post combustion capture will take

1 A key assumption of this study is that power plants are retired as soon as they reach a fixed age, 25 or 40 years depending on the technology, and are not retrofitted to have their operational lifetime extended.

2 All costs reported in this analysis are real costs discounted to the reference year 2005.

the largest share of new capacity built during the period from 2020 to 2030. Under the assumptions made in this study concerning the techno-economic performance of power plants, pulverised coal technology with post-combustion capture is not competitive, and so is not deployed in any of the examined scenarios. When CO_2 prices are low, CCS has no role in power generation.

If the power sector is to reduce CO_2 emissions to 20% below 1990 levels by 2020, the significant penetration of non-fossil fuel power generation technologies and high carbon prices will be needed. In a BAU case for the penetration of non-fossil fuel technologies, annual CO_2 emissions only reach this target with the introduction of CCS. In the policy case, this target can be achieved with high CO_2 prices regardless of the prices of fuels and the availability of CCS. Under low carbon prices, significant emission reductions can also be achieved in the policy case, but only in the event of very low natural gas prices. The deployment of carbon capture technology could be a complementary measure to greater use of non-fossil fuel power generation technologies, offering higher emission reductions in the longer term.

A high penetration of non-fossil electricity generation capacity (renewables and nuclear) will not only reduce emissions but will also promote the security of Europe's energy supply by diversifying the energy resource mix and reducing the demand for fossil fuels. In addition, a combination of high CO_2 prices plus the development of CCS technology and medium-high fuel prices, or a combination of low CO_2 prices and medium fuel prices irrespective of the commercialisation of CCS technology, will reduce the share of natural gas in the fuel mix and hence limit the vulnerability of the fossil fuel power generation sector to imported hydrocarbons. In contrast, if the contribution of non-fossil electricity generation is not increased, higher electricity demand and the resulting fuel consumption will lead to greater dependence on imports for the European energy system.

Electricity production costs follow the trends assumed for fuel and CO_2 prices as these costs are transferred on to the production cost of fossil-fuelled electricity. In general, when CO_2 costs are low, fossil electricity production costs are also at a minimum. When CO_2 prices are high, power generation becomes more expensive irrespective of the availability of CCS technology. Where CCS is not available, this is due to the CO_2 penalty and the increased use of natural gas, which is a more expensive fuel. On the other hand, CCS technology based on coal is inherently more expensive and less efficient. While the cost components may be different, the effect is the same: fossil electricity production costs are predicted to more than double by 2030. While capital requirements increase when the deployment of CCS technologies is considered, the penetration of CCS does not have a negative impact on the average production cost of fossil-fuelled electricity. A significant finding of the analysis is that, despite the higher capital costs associated with it, the deployment of carbon capture technology can help to control the increase in the production cost of fossil-fuelled electricity in a carbon-constrained environment where the price of CO_2 permits or penalties are high.

The study has identified the conditions that are favourable for the introduction of CCS technology in the power plant fleet. If CO_2 prices are high, making CCS compulsory will have no effect, as CCS technologies will already be the most competitive option and would have taken the maximum market share soon after commercialisation. Under low CO_2 prices, if conventional power plant options (Pulverised Coal (PC), Natural Gas Combined Cycle (NGCC)) are disregarded and CCS technology is forced as the only option for large-scale power generation, then the analysis indicates that the new capacity has a large share of open cycle gas turbines. This is not a likely development but rather an indication of the inability of the current methodology to cope with such market interventions, when capital and operating costs of CCS technology are much higher than those of conventional large-scale power plants.

Rather than an increased share of open cycle gas turbines, it is likely that there will be delays in the replacement and expansion of the fleet, leading to extensions of the operating life of aged power plants and the shrinkage of the reserve margin. As a result, CCS technology is introduced to the power generation system at a slower rate and does not reach the capacity level achieved through a fully competitive market.

Under the BAU case where fossil fuels maintain their current share in power generation for the next 25 years, the power sector cannot simultaneously meet all the objectives of the European energy policy. Increased shares of non-fossil electricity generation are essential for achieving the energy and environmental goals. In the event of medium to high fuel prices the policy goals are only achieved

with the deployment of CCS technology at greater expense and leading to higher costs which will influence competitiveness.

Without a CO_2 cost incentive, the policy goals are only met in a low fuel price environment. This scenario is also very beneficial in terms of competitiveness as both capital expenditure and electricity production costs are low. However, although CO_2 emissions and absolute fuel consumption could be reduced, irrespective of the CO_2 price and the commercialisation of CCS technology, the power generation sector would depend almost entirely on natural gas in 2030. This would have a detrimental effect on the security of energy supply.

In essence, the portfolio of fossil fuel power plants that will be deployed in the future will only be compatible with the European goal for the development of a more sustainable energy system if the following conditions are met: high CO_2 prices need to be maintained; further development and commercialisation of carbon capture technology is enabled; and medium or high fossil fuel prices prevail. The key conclusion is that for a sustainable and secure energy system we need to invest, both in increasing non-fossil fuel power generation and in CCS technologies to ensure that they are ready to be deployed when needed.

1 Introduction

Electricity demand in the European Union (EU) is rising, and the projection for the foreseeable future, as reported in energy outlooks published by the European Commission, IEA (International Energy Agency), etc., is that this trend will continue at a rate similar to the one experienced today. At the same time, the electricity generation infrastructure is aging and a large number of power plants are scheduled for retirement in the short and medium term. Unless new electricity generation capacity is created, the increase in electricity demand, coupled with a reduction in installed electricity generation capacity, could put the European power generation sector under significant strain in the coming years, with negative consequences for the European economy and the standard of living of Europe's citizens.

The electricity generation capacity that needs to be installed in the EU during the next twenty-five years is reported in pertinent literature to be approximately equal to the capacity installed today. The capital investment required for this expansion is in the order of several hundred billion[3] euros.

However, the expansion of the electricity generation sector has implications beyond the large capital requirements. Despite all efforts to increase the penetration of renewable energy sources (RES), and in view of the fact that nuclear energy remains a controversial subject, it is certain that fossil fuel power plants will remain the backbone of the electricity generation system, at least in the short and medium term. As a consequence, the energy sector will continue to depend on significant quantities of imported fossil fuels, increasing the vulnerability of the European energy system to disruptions to its energy supply. Relying on the use of fossil fuels on a large scale will pose a major obstacle to European efforts to curb carbon dioxide (CO_2) emissions as part of the fight against global climate change. On the other hand, the expansion of the power generation system represents a major opportunity for the replacement of today's old, less efficient and CO_2-emitting power plants with new ones based on advanced, more efficient and (near-) zero CO_2 emission technologies, thus paving the way towards a less carbon intensive electricity sector.

Seizing the opportunities and harvesting the maximum benefit that could come with the expansion of the electricity generation sector requires a carefully planned strategy. With the dawn of the 21st century the energy landscape in Europe has changed. Europe has an overall strategic objective to balance the goals of sustainable energy use, enhanced competitiveness and maintenance of the security of energy supply. The future portfolio of power plants should be designed to be compatible with these targets. Consequently, a key issue emerges: What is the *optimal*, yet realistic, composition of the future electricity generation technology and fuel mix that is best aligned with the goals of the EU policies (energy, environmental, economic, etc.)? And furthermore: Which conditions would lead to the development of such an *optimal* technology mix? Answering these questions necessitates a good understanding of the mechanisms that affect the future development of the electricity generation sector.

Views on the future power generation technology portfolio can already be found in assessments and outlooks for the energy sector, where the power plant technology mix is treated as an intermediate step in studying the effects of policies and current trends (market, demographic, economic, technological, etc.) on the whole energy system. These studies, however, are of little help when investigating how best plan the expansion of the electricity generation sector taking into account the EU's policy goals.

The aim of this study is to explore how the European *fossil fuel power plant fleet* could evolve in the period from now to 2030, given certain assumptions about the economic environment and technology development options. The specific objectives of this study are:

1. to calculate the capacity requirements for new fossil fuel power plants in the EU during the period to 2030 under different assumptions for the penetration of non-fossil power generation;

2. to describe the fossil fuel electricity generation technology mix in the EU under various scenarios for the evolution of fuel and CO_2 prices and technology options;

3. to assess the impact of each alternative scenario and of the corresponding power plant fleet on the European energy policy drivers, i.e. CO_2 emission reductions, competitiveness and energy security.

3 In the context of this study the term 'billion' refers to thousand million (10^9).

The focus has been intentionally set on fossil fuel technologies. The role of renewables in the future electricity sector has been thoroughly assessed in recent studies, the outcomes of which are used as an input in this work. Moreover, as the future role of nuclear energy throughout the EU depends mainly on political decisions rather than on techno-economic factors, this study adopts the related results from published energy outlooks and avoids embarking on speculations about political scenarios on nuclear energy. It thus assumes that the output of nuclear power plants will be either low (-15% compared to current levels) or high (30% greater than current levels).

The study uses a simple and transparent approach to develop and evaluate a number of scenarios on the evolution of the European energy system, in order to present alternative views of the future power generation technology and fuel mix. The influence of the factors mentioned above on the evolution of the fossil fuel power sector is highlighted through a number of indicators for each scenario examined, namely the capital investment required for the expansion of the power plant portfolio, the associated CO_2 emissions, fossil fuel requirements, fuel diversification, and an average production cost of electricity.

Ultimately, this study attempts to assess the impacts on the sustainability, competitiveness, and security of the European energy system by providing answers to the following questions.

- Which fossil fuel power plant technologies will be deployed in the medium term to 2030? At which extent and at what cost? How much fuel will they consume and how much CO_2 will they emit?
- Which conditions promote the development of a fossil fuel electricity generation technology mix that:
  - minimises CO_2 emissions?
  - has a positive impact on the security of supply?
  - supports European competitiveness?
- Under which scenario(s) is the electricity generation technology mix optimised so that it better serves in a balanced way all the objectives of the European energy strategy?

The study is structured as follows.

- The stage for the analysis is set in Chapter 2, where the case is made for the expansion of the electricity generation sector to be treated as an integral element of the overall European energy strategy, highlighting the consequences of expansion decisions for the whole energy system.
- Chapter 3 sets the theoretical background for the analysis, giving an overview of some methods used in expansion planning for electrical generating systems; and Chapter 4 describes the scenarios, the methodology followed and the assumptions made in this study.
- Chapter 5 is a snapshot of the current electricity generation sector, offering a detailed analysis of the fossil-fuel-fired capacity currently in operation and setting a baseline for the study.
- Chapters 6 and 7 describe the evolution of the fossil fuel power generation sector using a number of scenarios regarding the role of non-fossil fuel technologies in the future electricity generation system, the price of fossil fuels, the availability of CCS technology, and, the carbon market. Results are presented for the size and the technology mix of the fossil fuel electricity generation capacity, the capital and fuel requirements, the fuel mix, the electricity production costs and the carbon emissions from fossil fuel power generation.
- Finally, the impacts of all alternative expansion scenarios considered in this study on the goals of the European energy policy are assessed in Chapter 8, and the conclusions of the study are presented in Chapter 9.

2 The Electricity Generation System and the European Energy Strategy

The purpose of the power generation system is to satisfy electricity demand with an adequate quality of service at best cost. Electricity is generated by a portfolio of thermal, nuclear and hydro-power plants and other facilities, such as wind farms and photovoltaic systems that, eventually, have to be replaced for economic or technical reasons. New electricity generation capacity has to be constructed when a gap between electricity supply and demand is anticipated, caused by the retirement of old plants, and/or by an increasing electricity demand beyond the level that can be met by the capacity already installed and operational.

The planning for new electricity generation infrastructure has traditionally been performed based mainly on economic criteria, i.e. the minimisation of the lifetime costs made up by the capital investment and the operating costs. However, the choice of technologies to fill the gap between the installed and required electricity generation capacity not only affects the magnitude of the required capital investment, but also impacts greatly, among other things, on:

1. the emissions of greenhouse gases (GHG) from the power sector[4];
2. the generating cost of electricity, which in turn impacts on the quality of life of the European citizen and on the competitiveness of the European economy at large; and
3. the consumption of primary energy resources, with a concomitant effect on the security of energy supply.

These three issues are the prime drivers of the European energy policy [1, 2].

In this respect, the planning for the expansion of the electricity generation capacity should not be considered as an isolated issue that only concerns the electricity sector, but should rather be treated as a key aspect in the formulation of the overall European sustainable energy strategy.

4 The choice of electricity generation technologies will also affect the emissions of other pollutants, such as acid gases (NO_x and SO_x), heavy metals and particulate matter that deteriorate air quality.

2.1 The European energy challenge

Affordable and plentiful energy underpins European lifestyles and is an essential ingredient of economic prosperity. Yet, at the dawn of the 21st century, the EU, like the rest of the world, is confronted with the challenge of moving to a truly sustainable energy system. Among the most important issues that need to be addressed are the following.

- The threat of global warming [3, 4]: During the 20th century, the global average temperature rose by about 0.6°C, and it is projected to increase by 1.4°C to 5.8°C by 2100, with potentially devastating effects on the environment and human welfare. The energy sector is the main emitter of anthropogenic greenhouse gases, mainly carbon dioxide (CO_2), that are responsible for global warming.
- Promoting the competitiveness of European industry, and the whole European economy, to deliver stronger and lasting growth and create more and better jobs, in line with the Lisbon Strategy [5,6]: Achieving this necessitates, among other things, a reduction in the price of electricity by developing a fully functioning internal electricity market, and a strong investment in the research, development and deployment of advanced power generation technologies that will allow Europe to maintain and enhance its role as a global leader in advanced energy technologies.
- Promoting the security of energy supply [1,2,7]: The EU imports 50% of its energy requirements, and this dependency is projected to increase to 70% by 2030. Moreover, energy reserves are concentrated in just a few countries, increasing the vulnerability of the European energy system to disruptions in the supply of energy resources, mostly hydrocarbons. Furthermore, Europe has to cope with high and volatile energy prices, and the increasing strain on world energy resources caused by growing energy consumption in the developing world.

In January 2007, the European Commission proposed a comprehensive package of measures to establish a new energy policy for Europe addressing these three headline issues. This was subsequently endorsed by the Spring Council of the EU [8]. Among

other things, the energy package[5] proposes a reduction in greenhouse gas emissions to at least 20% below the 1990 levels and an increase in the contribution of RES to total energy consumption to 20%, both to be achieved by 2020 [9]. The package is complemented by a Communication on limiting global temperature rise to 2°C [4].

The energy package ties in with previous initiatives: In the fight against climate change, the EU has ratified the Kyoto Protocol, adopted a number of Directives on the promotion of renewable energy sources and biofuels, and established the CO_2 emissions trading scheme (ETS). Moreover, a set of additional measures has been proposed in the Communication from the Commission entitled *Winning the Battle Against Global Climate Change* [3] and by the European Climate Change Programme (ECCP).

Actions by the Commission to improve competitiveness include a set of measures proposed through the Communication *Common Actions for Growth and Employment: The Community Lisbon Programme* [10] and the creation of a High Level Group on Competitiveness, Energy and Environment that aims to:

1. foster closer coordination between policy and legislative initiatives;
2. contribute to creating a more stable and predictable regulatory framework;
3. explore ways to enhance the growth potential of European industries by further integrating competitiveness, energy and environmental policies.

Finally, concerning the security of energy supply, a series of measures has been implemented to promote energy efficiency and set targets for the penetration of renewables in the electricity generation and transport sectors. A number of proposals for additional measures have been made through the recently published Green Paper *A European Strategy for Sustainable, Competitive and Secure Energy* [2] and in an earlier Green Paper *Security of Energy Supply* [7]. Lastly, a vision of a long term framework for the external energy dimension has been set out jointly by the Commission and the Council.

2.2 The significance of the electricity generation sector

The electricity sector has a central position in the European energy system. Electricity accounts for 20% of the final energy consumption in the EU, meeting 29.4% of the needs of the industrial sector and 27.2% of the needs of services and households [11].

Electricity's dominant position will be reinforced in the future as Europe will continue to shift from primary fuels to electricity as an energy carrier. The demand for electricity has been increasing at an average rate of about 2% annually since the 1990s [11] and there are no indications that this demand will be curbed significantly despite all the energy savings and improved efficiency measures that have been implemented. According to the baseline scenario of the European energy outlook to 2030, the final electricity demand in the EU will increase by about 50% between 2004 and 2030 and its contribution to the final energy consumption will rise to 22.5% [12]. The increasing demand for electricity can only be addressed by building new generation capacity, especially in view of the fact that the potential for electricity imports from outside the EU is small, being estimated to meet just 0.7% of electricity demand in 2030 [12].

It has further been projected [12] that the *additional* capacity needed to meet the growing electricity demand by 2030 is about 400 GW, raising the total installed capacity to 55% above current levels. However the need for new capacity is larger than that required for meeting the increasing demand. The European power plant fleet is aging, and a large number of installations will be retiring within the coming decade. For example, more than half of the fossil fuel power plant capacity, which is equivalent to about a quarter of the total installed capacity in the EU, is over 20 years old, and approximately 6% of the fossil fuel power plants are more than 40 years old (see Chapter 5).

According to the International Energy Agency investment outlook [13], approximately 330 GW of existing power stations in the EU will have to be replaced by 2030. This figure is raised to approximately 400 GW in the Annex to the European

5 More information on the *energy package* as well as the official documents can be found on the internet site of the European Commission, http://ec.europa.eu/energy/energy_policy/documents_en.htm (last accessed by the authors on 9 February 2009).

Commission's Green Paper *A European Strategy for Sustainable, Competitive and Secure Energy* [6]. Overall, the total capacity that will have to be constructed by 2030 to both meet the increasing demand for electricity and replace retiring plants is estimated to reach a staggering 650 – 730 GW [3, 12, 6], which is in the same order of magnitude as the total electrical capacity currently installed (706 GW in 2004 [11]).

Building new infrastructure on such a scale in the coming 25 years is a major challenge, as the financial resources required are massive. According to the IEA [13], the total investment needed for these new power generation projects in the EU could reach USD 525 billion, or approximately EUR 440 billion[6]. The Annex to the Green Paper raises this figure to EUR 625 billion [6]; and the Communication from the Commission *Winning the Battle Against Global Climate Change* [3], increases this further to EUR 1 200 billion. Although these references do not provide any details on how these values have been estimated, the origin of these differences should be sought in the composition of the portfolio of electricity generation technologies that was considered in each case.

Despite their differences in outcome regarding the composition of the future electricity generation technology mix, all energy outlooks tend to agree that the contribution of RES will increase, while not reaching the point of dominating the electricity generation sector. The nuclear power plant capacity will either shrink or remain unchanged. As a consequence, all these studies accept that fossil fuel power plants will remain the backbone of the electricity generating sector, at least until 2030.

Solutions therefore need to be sought to make the continual use of fossil fuels compatible with the goals of the European energy policy. These solutions should be considered during the planning for the optimal electricity generation technology mix of the future.

The fight against climate change necessitates the reduction of greenhouse gas emissions from the electricity generation sector, which in turn can be achieved with the deployment of CO_2-neutral or carbon-lean technologies. But, as was explained above, while renewables, and possibly nuclear power plants, will fill some of the gap between installed and required electricity generation capacity, most of the new plants will inevitably be of the fossil fuel type. The goal of reducing CO_2 emissions from fossil fuel power plants can be achieved in the short term with the development and deployment of power plants with superior efficiency compared to the plants in operation today and by shifting to less carbon intensive fuels, such as natural gas and biomass. However, a stronger shift to gas will have significant negative consequences for the security of energy supply.

Nevertheless, irrespective of the fuel chosen, it is likely that, unless carbon capture and storage technologies are developed and implemented in new power plants, the greenhouse gas emissions from the power sector will increase in the medium and long term. This would nullify any post-Kyoto agreements designed to fight climate change and make it harder to meet the target of a limiting global temperature rise to a maximum of 2°C[7] [3]. According to the Zero Emissions Fossil Fuel Power Plant Technology Platform (ZEP TP), plants featuring carbon capture and storage technologies could be commercially deployed on a large scale as of 2020, while first-of-a-kind plants could be operational around 2015. Therefore, the renewal of the fossil fuel power plant fleet offers an opportunity for the decarbonisation of the power sector, provided that carbon capture technologies are applied to new power plants built from 2020 onwards or even earlier. The utilisation of this technology could offer a temporary solution to the issue of having to use fossil fuels while avoiding further CO_2 emissions, until more competitive renewable energy sources and other decarbonised energy carriers, such as hydrogen, become the main sources and carriers of energy.

It needs to be stressed however, that power plants with carbon capture will be more expensive to build and operate, than similar plants that do not capture CO_2. Hence, if the sole criterion for selecting a technology for a power plant is that of lowest costs, such technologies could never be deployed in the absence of incentives for carbon capture and storage.

Any choices concerning the technology and fuel mix of the fossil fuel power generation sector affect the competitiveness of the European economy. The

6 All costs reported in this analysis are real current costs discounted to the reference year 2005. The annual exchange rate for 2005 according to EUROSTAT was EUR 1 = USD 1.2441.

7 To meet the target of a maximum of 2°C raise in global temperature above pre-industrial levels, global GHG emissions should peak no later than 2025 and then fall by at least 15% to 50% compared to 1990 levels [3].

selection of expensive conversion technologies, or a non-optimal fuel mix from the point of view of fossil fuel pricing, would increase electricity production costs, which could be detrimental to economic growth. Increased costs for electricity generation would raise the cost of European products thus making them less competitive in domestic and international markets; or drain significant financial resources that could otherwise be invested in other sectors of the economy.

It should be noted that the drive for increased competitiveness requires, among other things, the development of a fully functioning internal market based on the competition between utilities, which will bring the cost of energy down and increase the quality of service. This in turn may favour the construction of power plants with low capital and operating costs, as utilities make their expansion planning based on the criterion of maximising profitability. These low cost plants, however, may not be the optimal choice for reducing CO_2 emissions, or may not operate on an ideal fuel mix that maintains the security of energy supply in the medium and long term. On the other hand, the development and construction of advanced power plants, especially those that capture CO_2, will create significant opportunities for European industry to maintain and enhance its role as a key exporter of sophisticated fossil fuel conversion technologies.

Finally, any choices for the future fuel and technology mix will have a major impact on the security of energy supply, which necessitates the development of a diverse fuel mix and a more efficient technology mix for the electricity generation sector that limits the EU's external vulnerability to imported hydrocarbons[8]. Relying on the most economically attractive technology may lead to overdependence on a single energy source, increasing the vulnerability of the energy system to disruptions to the energy supply. On the other hand, pursuing the security of energy supply, e.g. by dictating a predefined fuel mix, could bias the development of the technology mix in the power sector, diverting it from the path that would have been followed if the paramount objective were solely the reduction of greenhouse gas emissions or the strengthening of Europe's competitiveness.

2.3 The role of electricity capacity planning

The arguments made in the previous section imply that there may not be a unique solution, i.e. an optimal fuel and technology mix for the fossil fuel power generation sector that could simultaneously fulfil all of the objectives of the EU energy policy. This has also been recognised in the Green Paper on *an energy policy for Europe* and the Communication from the Commission on *winning the battle against global climate change*, both of which stress the need for an integrated approach to the development of the European energy policy. In this context, in order to take full advantage of all the opportunities that could arise from the construction of a large electricity generation capacity in the coming years, this expansion should be well planned and based on an overall strategic objective to balance the goals of tackling climate change and improving both competitiveness and security of energy supply.

Policy makers and regulatory authorities should have a strongly influence on the expansion of the power sector. Appropriate policies must be in place to guide the evolution of the electricity generation sector in such a way that is aligned with the goals of the energy policy. In this respect, a systematic analysis of information about technology and electricity supply and demand is an invaluable tool for identifying the measures that need to be taken to develop the most suitable policies.

It should be stressed that there is no room for delays or errors in planning for the new fossil fuel electricity generation capacity. Indeed, a large amount of capacity will have to be constructed within the next 25 years, and the planning for this needs to be done 5 to 10 years ahead of construction. In view of the long life of power plants, in excess of 25 to 40 years, the policy maker needs to have a good understanding of the issues surrounding the evolution of the power generation sector if they are to engage in an efficient dialogue with the power industry and achieve their energy policy goals. Unwise choices for the future technology and fuel mix could haunt the energy system through the long term, setting obstacles on the path to sustainability, competitiveness and energy security.

8 Nevertheless, these two conditions, fuel diversification and the adoption of more efficient technologies, may not go hand-in-hand. Power utilities are willing to sacrifice energy efficiency for fuel flexibility as this reduces the risk associated with fuel supply.

3 Basics of Expansion Planning for Electricity Generation Systems

Planning for the expansion of an electricity generation system is an integrated process that involves analysing the anticipated demand for electricity and making an objective choice for the optimal portfolio of new power plants[9] that should be installed to ensure an adequate supply of electricity to users. In this context, the decision for the technology mix of the new power plant fleet is based on a thorough consideration of financial and fuel resources, environmental and policy constraints, the techno-economic performance of different types of power plants and the anticipated evolution of all these factors.

Capacity planning is carried out over a long-term horizon, in view of the long technical lifetimes of power plants and their long-term impact on the energy system. Typically, the aim of planning is to identify the magnitude of new capacity needed, recommend the portfolio of power plant types that will have to be constructed and determine where they should be built as well as the timing of their construction and when they should become operational. However, the planning of new capacity may go a step further and prepare a capital investment plan for the construction of the necessary infrastructure, provide signals to policy makers and regulators concerning the likely evolution of the electricity sector in the future and recommend the development of policies for the power sector.

A number of models and tools have been developed in support of capacity planning activities; these are described in detail in [14]. This chapter outlines the general methodology that is typically followed during capacity planning, describing in more detail the models that are used in this study.

9 The term 'power plant' in this chapter refers to any type of infrastructure that can generate electricity.

3.1 Capacity planning methodology

The planning for new electricity generation capacity is usually performed in three stages (see Figure 3.1).

1. Forecasting the electricity demand within a given control (service) area of an electrical system, which typically covers an entire country, throughout the time span of the planning.

2. Carrying out a techno-economic assessment of all power generation technologies that are mature enough to be deployed during the time horizon of the planning. This step is frequently complemented by an additional analysis of the availability of energy resources, which may set boundary conditions to the planning by recommending or restricting the use of specific types of energy resources (e.g. by promoting the use of indigenous coal, or limiting the use of imported natural gas).

3. Balancing electricity demand and supply within the temporal boundaries of the planning, and estimating the capacity needed and the electricity generation technology mix. This is followed by an impact assessment, before a decision is made.

These steps are described in detail in the following sections.

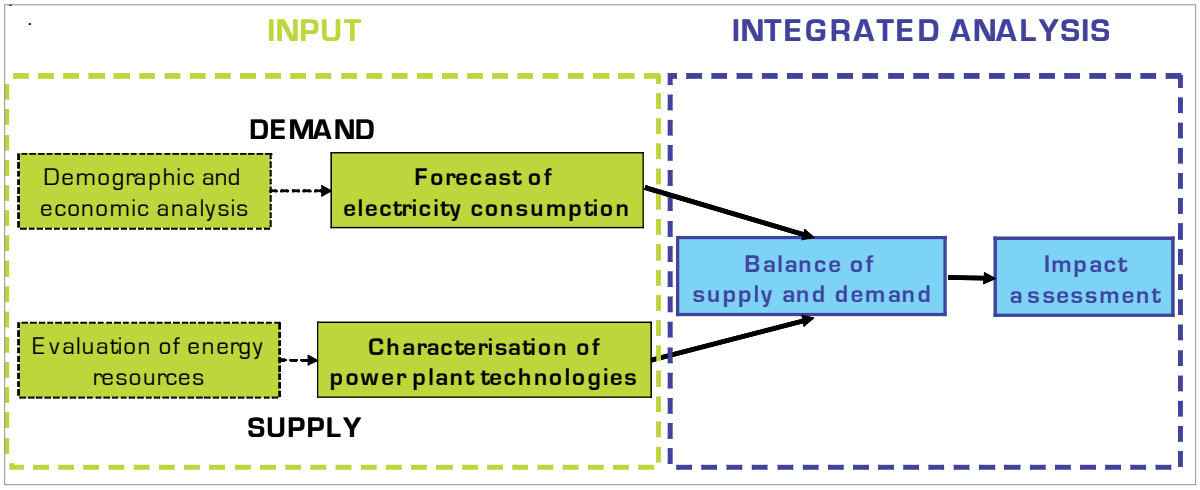

Figure 3.1: Stages in electricity generation capacity planning (after [14])

3.2 Forecast of electricity demand

Forecasting electricity demand is a very complex task due to uncertainties over the time span of the planning. In the short term, hours or days, the profile and magnitude of electricity demand depends mainly on the time of day and the weather conditions. The relationship between demand and the average daily temperature in a control area is, however, stochastic [17], impeding the accurate prediction of electricity consumption a few days in advance, even when reliable information concerning anticipated weather conditions is available. In the medium and long term, the demand for electricity depends on other factors that are also difficult to predict, namely:

1. economic development within the control area: the demand for electricity (as well as for energy) is linked to economic activity and hence to the gross domestic product; this relationship is portrayed through energy intensity indicators;

2. changes in consumption behaviour due to, for example, improvements in living conditions (e.g., wider use of air-conditioning, operation of additional electrical appliances, changes in the opening hours of markets);

3. demographic and population changes;

4. the overall situation in the energy sector and in electricity markets (e.g. changes in electricity and energy resource prices);

5. the implementation of policies such as energy savings, emissions constraints, etc.

In view of this complexity, two different approaches can be followed for forecasting electricity demand [14]: The prospective approach, which is based on the projection of past trends; and the normative approach, which is based on the postulation of scenarios. In the latter approach, scenarios are designed to explore possible future configurations of the energy system by describing hypothetical sequences of events (e.g., evolution of population and economic growth, fuel prices, technological innovation) that could develop over a period of time. It should be emphasised that scenarios do not predict the future, i.e. they do not serve the same purpose as traditional business forecasting tools. As such, a value of likelihood cannot be assigned to any particular scenario. Overall, the normative approach is more advantageous than the prospective approach, as it can take into account structural, political and behavioural changes. For these reasons, it is usually preferred for planning purposes [16].

Forecasts for electricity demand are produced with the help of macroeconomic and sectoral economic analyses based on pre-described scenarios and using econometric models that postulate casual relationships between electricity demand and economic activity, population, technology trends, etc. The forecasts are further treated to yield the type of information required for capacity planning: (i) the *peak load*, and, (ii) the profile of electricity demand, that is typically portrayed in a *load duration curve*. These terms are explained below.

3.2.1 The peak load

As with electricity demand, the electrical load, i.e. the amount of electrical power generated by the electrical system and delivered to consumers, varies with time. Although some patterns of load variation are predictable, for example the electrical load is low at night and high during the day, absolute load values vary between hours or days. An example of the variation of the *average hourly load* during a calendar day in two control areas, Greece and Belgium, countries with comparable populations, is shown in Figure 3.2. In this figure, load data from the electrical system of continental Greece and the islands connected to this, and from that of Belgium (excluding the AIESH grid but including the Sotel Luxemburgish grid), as reported by the corresponding transmission system operators, HTSO S.A. [18] and Elia [19] respectively, are plotted against the hours of the day. The pattern of electrical load in these two control areas is similar: the load reaches a minimum around 8 a.m. and peaks around 1 p.m. and 8 p.m.

The variation of load is typically shown using *load curves*, plots of temporal average loads (hourly, half-hourly, etc.) ranked by the actual time of occurrence. Figure 3.3 shows the load curves for four days in the Greek and the Belgian electrical systems: a summer and a winter Sunday, and a summer and a winter weekday. Although an overall pattern of load variation is identifiable, the load depended on the time of day and the period of the year as a result of the associated activity and the weather conditions that were prevailing in each control area.

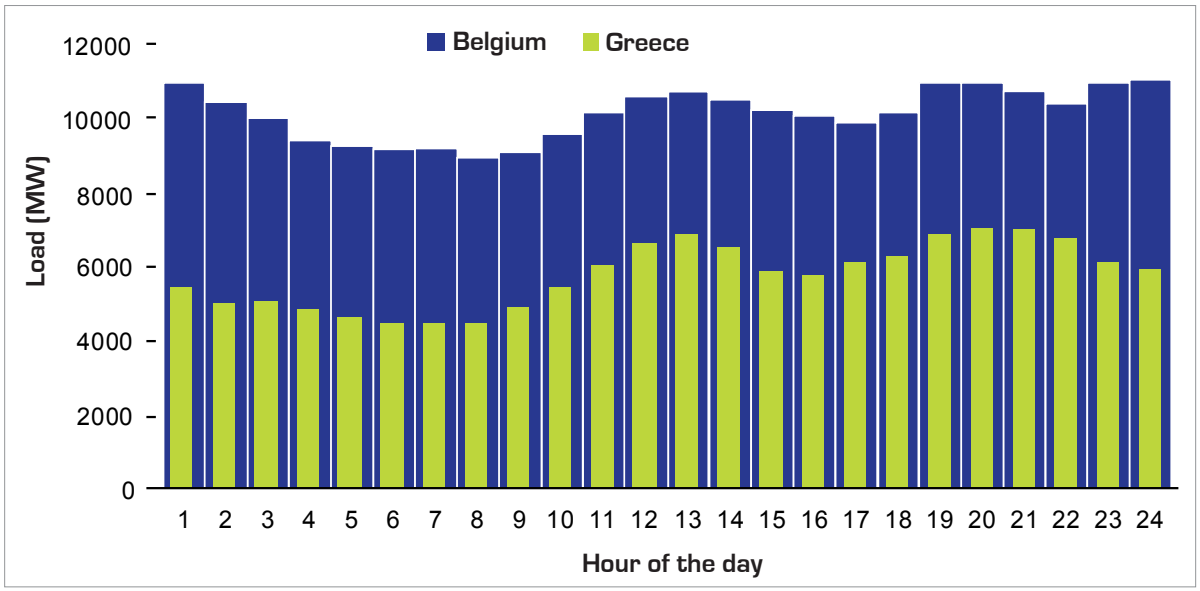

Figure 3.2: Average hourly loads in the Greek and the Belgian electrical systems on 5 February 2006 [18, 19]

It should be stressed that the different control areas within the EU do not reach their maximum and minimum daily loads during the same periods of the year. As can be seen in Figure 3.3, the *peak daily load*, i.e. the maximum load during a day, was the highest in Greece on the summer Sunday (9.3 GW) and the lowest on the winter Sunday (7.1 GW); furthermore, the ratio of the daily peak to the minimum load was highest during the winter weekday (1.71) and lowest during the summer weekday (1.43).

In contrast the load patterns in the Belgian system on the same four days showed the opposite pattern: the peak load was highest during the winter weekday (13.1 GW) and the lowest on the summer weekday (9.3 GW). Meanwhile the ratio of the daily peak to the minimum load was highest on the summer Sunday (1.40) and lowest on the winter Sunday (1.23). Similar observations can be made for the daily electricity consumption which is equal to the area under each load curve. In the same example, the amount of electrical energy delivered to users in Greece was highest on the summer Sunday (186 GWh) and lowest on the winter Sunday (139 GWh).

In Belgium, the consumption pattern during the same four days was also different. The maximum consumption occurred on the winter weekday (284 GWh) and the minimum on the summer weekday (182 GWh). Although these observations are based on a specific example, a more detailed analysis of load data from the EU control areas proves that the above statements hold true and there is a difference in load and consumption data between control areas in the northern and southern Europe.

Forecasting peak load is of paramount importance for capacity planning. At any time, the installed electricity generation capacity in a control area should be able to provide the electricity market

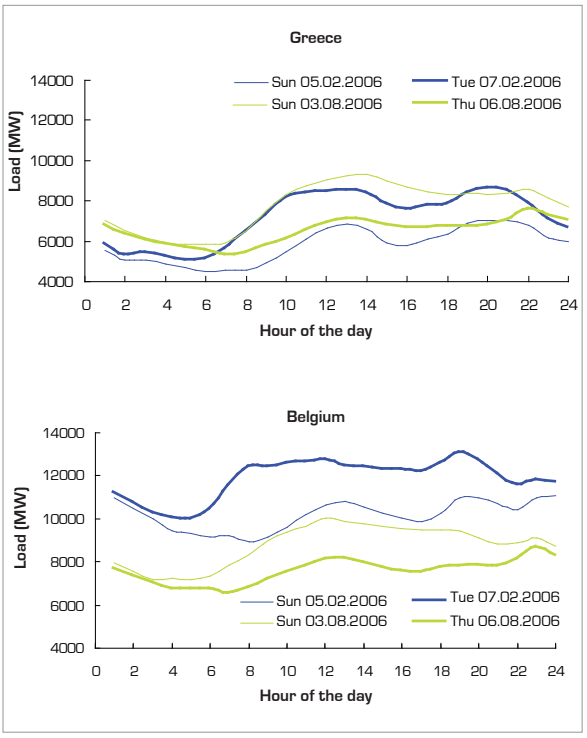

Figure 3.3: Load curves for four days in 2006 (Sunday in summer, weekday in summer, Sunday in winter, weekday in winter) in the Greek and the Belgian electrical systems [18, 19]

with a load at least equal to the anticipated peak to avoid disruptions to the electricity supply. However, the planning must also consider events that could reduce the generation of electricity from the installed capacity, such as the scheduled maintenance of power plants or unexpected equipment breakdown. In addition to this, it should be able to provide additional load, in case the peak load had been underestimated during planning. Traditionally, planners use two basic indicators to assess the ability of a generation system to cover securely the demand for electricity within a given time period, e.g. a year.

1. *The loss of load probability (LOLP)*. This expresses the number of days or hours during the year that the electricity generation system cannot meet the demand and is estimated using a stochastic methodology.

2. *The loss of energy probability (LOEP)*. This is also calculated stochastically and represents the amount of electrical energy that cannot be supplied by the available power plants.

Details for these indicators can be found in the literature, e.g. in [14]. In the context of this analysis it suffices to mention that acceptable values for LOLP and LOEP necessitate an adequate reserve margin in installed capacity of the order of 15% to 20% of the forecasted peak load.

Forecasts for the peak load are traditionally deduced from forecasts of electricity demand, using the *peak load factor* approach. The peak load factor of an electrical system is defined as the ratio of the average electrical load in a year (i.e. the annual electricity demand divided by the number of hours in a year) to the peak load anticipated in the same period:

$$\text{Peak Load Factor} = \frac{\text{Average Annual Load}}{\text{Peak Load}} = \frac{\text{Annual Electricity Demand}}{\text{Peak Load} * 8760 \text{ hours in a year}}$$

The peak load is estimated by solving the above equation, using as input the forecasts for the annual electricity demand (using the methods discussed above) and for the peak load factor[10]. The peak load factor is forecasted judgmentally, or by extrapolating current trends. While the above described approach is easy to implement, it may lead to errors if changes in the peak load factor have not been anticipated. Overall, the accuracy of a peak load estimate depends mainly on the accuracy of the electricity demand forecast and to a lesser extent the peak load factor. Overestimating electricity demand will impose great costs on the electrical system due to the build-up of excess capacity, while underestimating demand will lead to an unreliable electrical system that is unable to meet the electricity demand.

3.2.2 The load duration curve

While the peak load dictates the magnitude of the installed capacity, it does not provide any information on the use of electricity, i.e. how many hours of a given period loads will have a certain value. This information is essential for identifying the power generation technology mix and the operation of the installed capacity, as will be explained in the following section.

This type of information is extracted from a *load duration curve*. The load duration curve is a graphic representation of the distribution of loads in the electrical system; in other words a rearrangement of loads within a time period from the highest to the lowest. Figure 3.4 shows the *daily load duration curves* of the load curves of the Greek electrical system shown in Figure 3.3. In this example, on 5 February 2006, the load in the Greek electrical system was greater than 6 000 MW for 12 hours.

The *annual load duration curve* of a control area is calculated by combining all average (hourly, quarterly, etc.) loads generated within a calendar year. The load duration curves for Greece and Belgium for 2005 are shown in Figure 3.5.

10 Another, more complex forecast approach is the use of time series analysis [14].

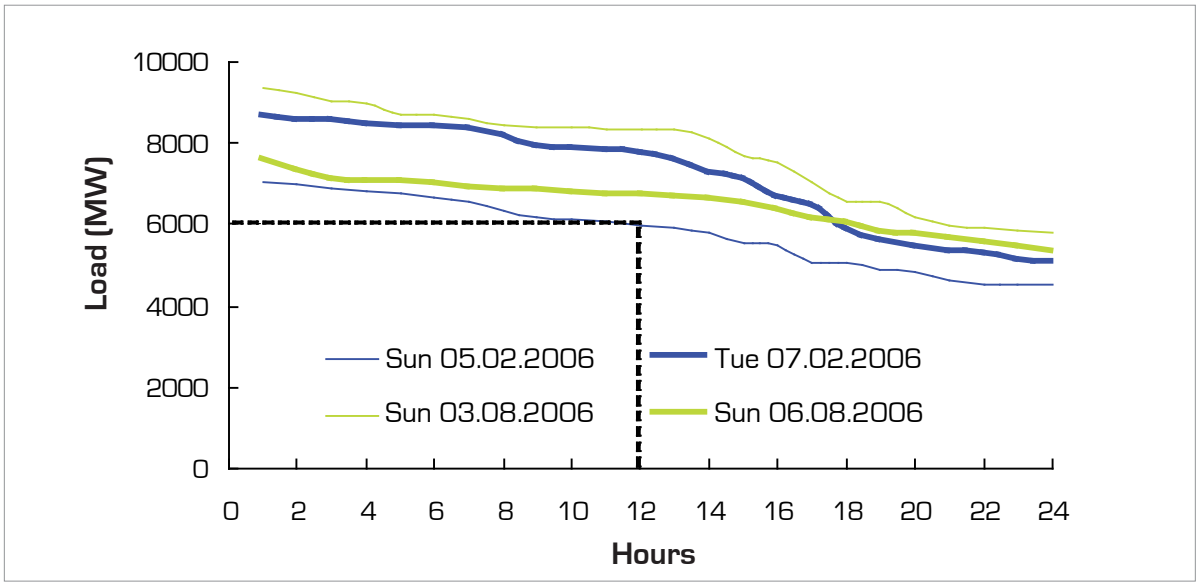

Figure 3.4: Daily load duration curves of the load curves shown in Figure 3.3 for Greece

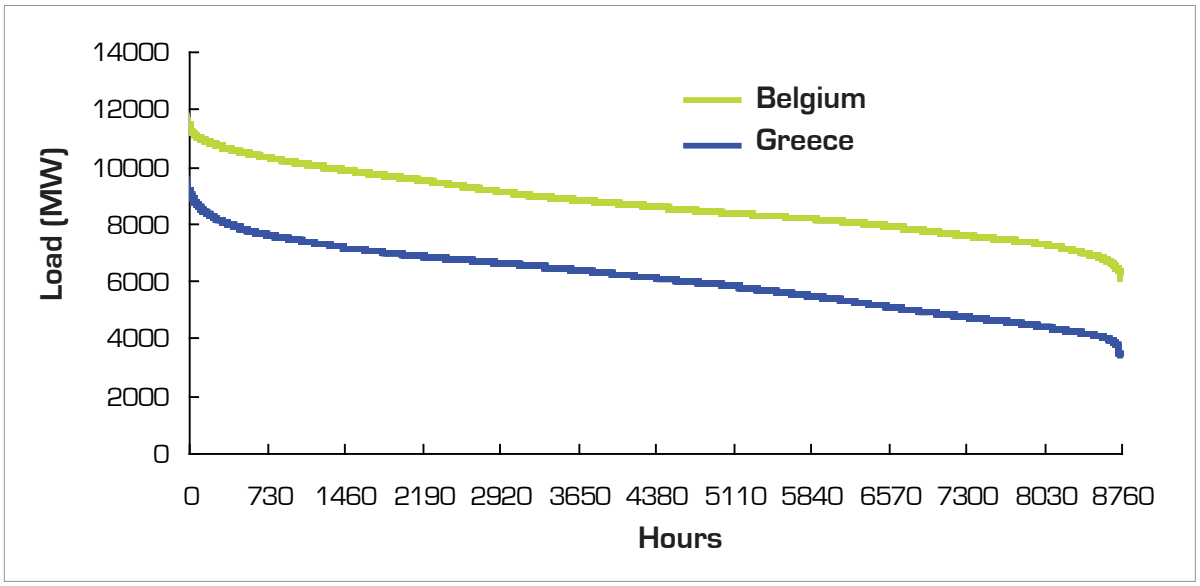

Figure 3.5: Load duration curves for the Greek and the Belgian electricity systems, 2005 [17, 19]

Projecting load duration curves in the future is another very complex task. A simple technique is to use the latest known *normalised load duration curve* and combine this with the projected peak load for each corresponding period [14]. Examples of normalised load duration curves are shown in Figure 3.6. The vertical axis shows the ratio of load over the annual peak load; and the horizontal axis the ratio of time (in hours) over the total number of hours within a year, i.e. 8 760. This method assumes that the pattern of electricity use will not change over time and that the load change will be distributed consistently over all types of demand. Therefore this method cannot cope with changes in the characteristics of demand in the future. In practice, analysts draw on their experience to add or subtract from the shape of the load duration curve, and make the total electrical energy (the area under the load duration curve) correspond to the forecast for the electricity demand. However, such adjustments may lead to significant errors, as the shape of the load duration curve influences the capacity attributed to different power plant technologies [14], as will be explained below.

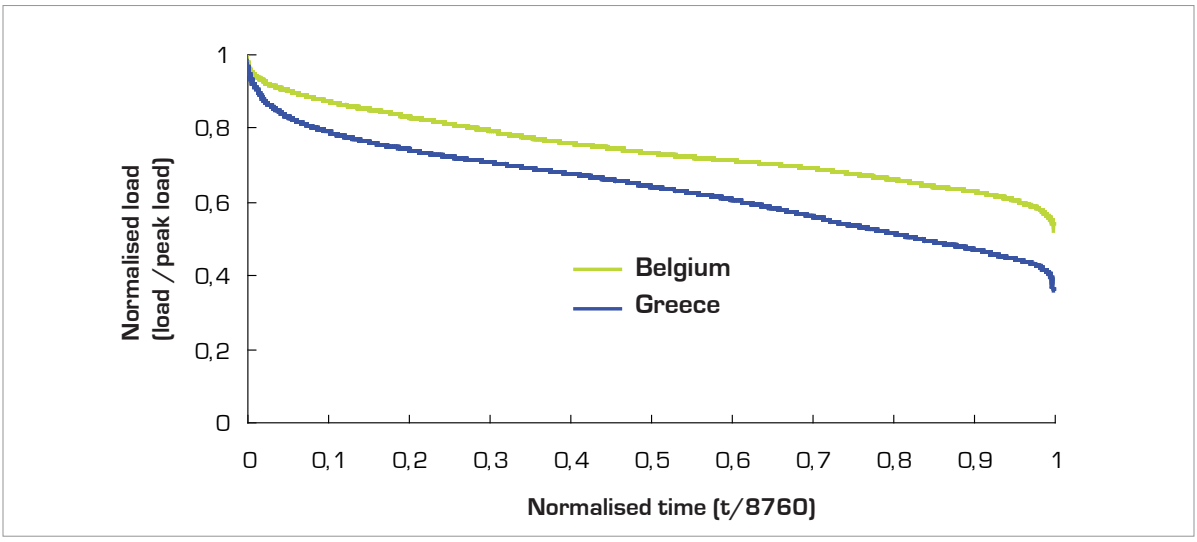

Figure 3.6: Normalisation of the load duration curves shown in Figure 3.5

3.3 The role of power plant technology assessment

Various power plant types are available for the expansion of the electricity generation system, such as pulverised coal plants, gas turbine combined cycle plants, nuclear power plants, hydropower plants, wind turbines, photovoltaics, open cycle gas turbines, diesel turbines and internal combustion reciprocating engines. The selection of the most suitable types of power plant for the power generation portfolio is based to a great extent on their specific operational performance and cost characteristics.

Power plants have traditionally been grouped according to their mode of operation into base load, peak load, and load-following[11].

- Base load plants are large plants designed to operate continuously for at least 60% of the year, generating electricity at a constant rate, irrespective of the electricity demand, except in the case of repairs or maintenance. They have (with the exception of combined cycle plants) low operating costs and high thermal efficiencies, but in general they are more expensive to build and have long start-up times.

- Load following plants operate for approximately 20% to 40% of the year, reducing their output, even shutting down, during periods of low demand, for example during the night or at weekends. Typically, load following plants are older base load plants that have been replaced by more efficient new capacity.

- Peak load plants operate only when there is a high demand for electricity, from as much as few hours a day to a few hours per year (no more than 10% of the year in total). They are not as efficient as the base load plants, hence they have higher operating costs, but they are cheaper to construct and they have very short start-up times.

The sorting of power plants into the above mentioned groups changes over time. Key criteria are the economics of electricity generation and the technical ability of the plant to adapt to rapid changes in power output in response to changes in demand. Until the early 1990s, base load plants included 'must-run' plants such as nuclear and coal-fired units. Load-following plants were predominantly oil-fired plants, while the peak load plants comprised oil and diesel engines. Hydropower plants with a reservoir are also very suitable for load following and peak load operation. By the late 1990s, gas-fired combined cycle plants had a major share in the base load power plant fleet, due to their high efficiencies and low construction costs. This displaced coal plants to the load-following category, while open cycle gas turbines dominated the peak load. However, recent increases in gas prices are likely to reverse the situation again with regards to base load, with new coal plants becoming base load units, displacing natural gas combined cycle plants to a load-following mode of operation.

11 The terms intermediate and mid-merit are also used in the literature in the same context.

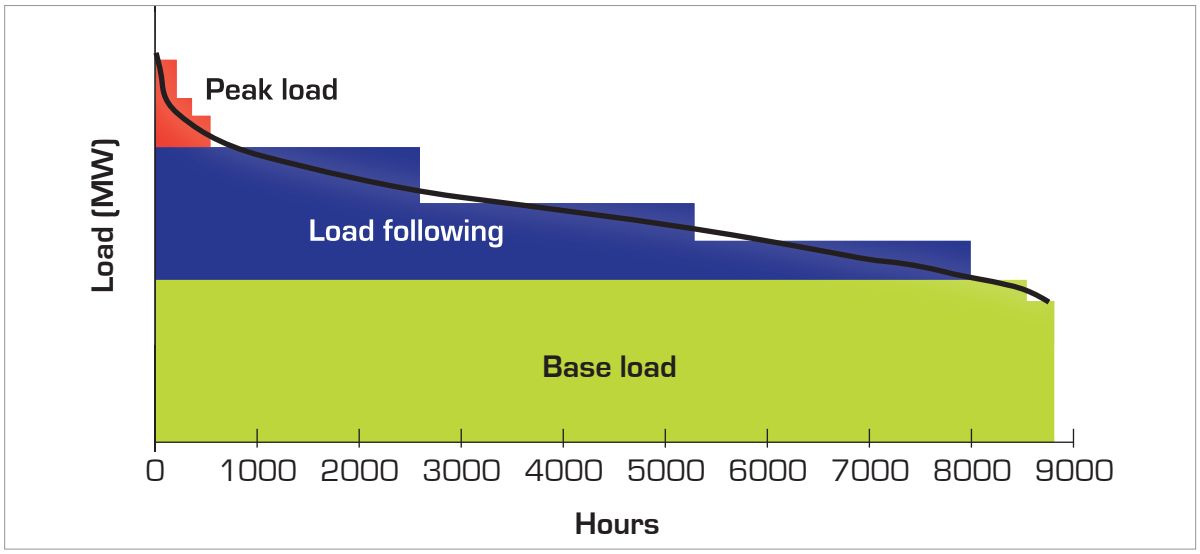

Figure 3.7: Schematic representation of the contribution of base load, load following and peak load plants in the generation capacity of an electrical system as a result of the shape of a load duration curve. The coloured steps in the graph represent the capacity of individual power plants; and the height of each coloured segment is an indication of the capacity of plants in the corresponding mode of operation.

The share of these groups of power plants in the electrical generation system depends on the requirements for peak and base load, which is reflected in the shape of the load duration curve. This is schematically shown in Figure 3.7. The share of base load plants is high when the load duration curve is flattened, while on the contrary, a prominent peak will necessitate a large peak plant capacity. However, the shape of the load duration curve is not the only determinant of the technology mix. This is influenced by the shape of the load duration curve in combination with the cost attributes of the different power plant types.

The annual electricity generation cost for a power plant comprises two components.

- The annual fixed costs that are independent of the amount of electricity the plant generates in a year. These include fixed charges to the capital expenditure (CAPEX) and the fixed operating and maintenance costs (FOM).

- The variable costs that are proportional to the amount of electricity generated, namely the variable operating and maintenance costs (VOM) and the fuel costs.

The CAPEX includes the costs of building the plant and bringing it to commercial operation and the costs related to interest charges accrued during the construction period. The construction costs are further split into direct costs and indirect costs (owner's costs, contingencies, spare parts, etc.). Typically, CAPEX is reported with reference to the power plant capacity using a term called specific capital investment (SCI), expressed in EUR/kW. Capital costs vary greatly between power plant types. Moreover, they even vary between plants of the same type, influenced by the size and location of the plant, the construction schedule, local costs, regulations in place, etc. For example, according to NEA/IEA (Nuclear Energy Agency/International Energy Agency), the specific overnight construction costs for most coal-fired power plants built in the OECD (Organisation for Economic Co-operation and Development) range between EUR 800/kW and EUR 1 200/kW and for natural gas-fired plants between EUR 320/kW and EUR 640/kW [20]. These capital investment costs are recovered annually through a fixed investment charge which is calculated using a capital recovery factor that depends on the time allowed for the pay-off of the investment (N in years) and the discount rate *i*:

$$\text{Fixed Investment Charge} = \text{CAPEX} * \frac{i(1+i)^N}{(1+i)^N - 1}$$

The FOM costs include taxes and insurance, personnel administration costs and, typically, the annual overhaul.

Power plant group	Annual fixed cost (F_i)	Variable cost per unit of electrical energy generated (V_i)
Base load	High	Low
Load following	Medium	Medium
Peak load	Low	High

Table 3.1: Cost characteristics of groups of power plant types (after [21])

The VOM costs include the cost of consumables (chemicals, catalysts, etc.), the cost of waste disposal and the cost of unscheduled repairs. The variable costs may change throughout the life of a plant.

The categorisation of the various cost elements is rather arbitrary. Some planners include the annual overhaul in the variable costs, or attribute a fraction of the fuel costs to the fixed costs to account for the development of a safety stock.

These cost components are used to calculate the total electricity generation cost for a power plant during a given time period, for example a year. The annual costs are typically expressed in relation to the capacity of the plant as EUR/kW per year. The annual costs are made up of both fixed and variable components. Even when the power plant does not operate at all, it still has to pay for its fixed costs (F_j) i.e. the capital investment charge and the FOM that depend only on the size of the plant, i.e. its capacity. These fixed costs are expressed in monetary units per installed power plant capacity (EUR/kW).

The variable costs that accrue during plant operation (V_j), i.e. fuel costs and VOM, depend on the time (number of hours) that the plant runs over the year. Variable costs are expressed in monetary units per electrical energy generated (EUR/kWh). The total annual cost for each kW of capacity of a power plant that operates t hours per year is therefore:

$$\text{Annual cost } (€/kW) = Fj(€/kW) + Vj(€/kWh) * t(h)$$

This relationship between annual hours of operation and total annual costs for any plant is graphically shown in Figure 3.8. This is the *cost curve* of a power plant. The intercept of the y-axis represents the annual fixed costs (F_j) and the slope of the line the variable costs (V_j).

Each power plant type has its own fixed and variable cost characteristics, as mentioned above, and hence is represented by its own characteristic cost curve. The general cost characteristics of the different groups of power plant types are summarised in Table 3.1.

In the context of capacity planning, the different types of power plant are compared on the basis of actual cost figures, and the most competitive ones are selected using methodologies described in the next section. However, there are many uncertainties in the evaluation of the economic performance of power plants since, as mentioned above, costs vary even between plants of the same type. This uncertainty is further increased when the costs

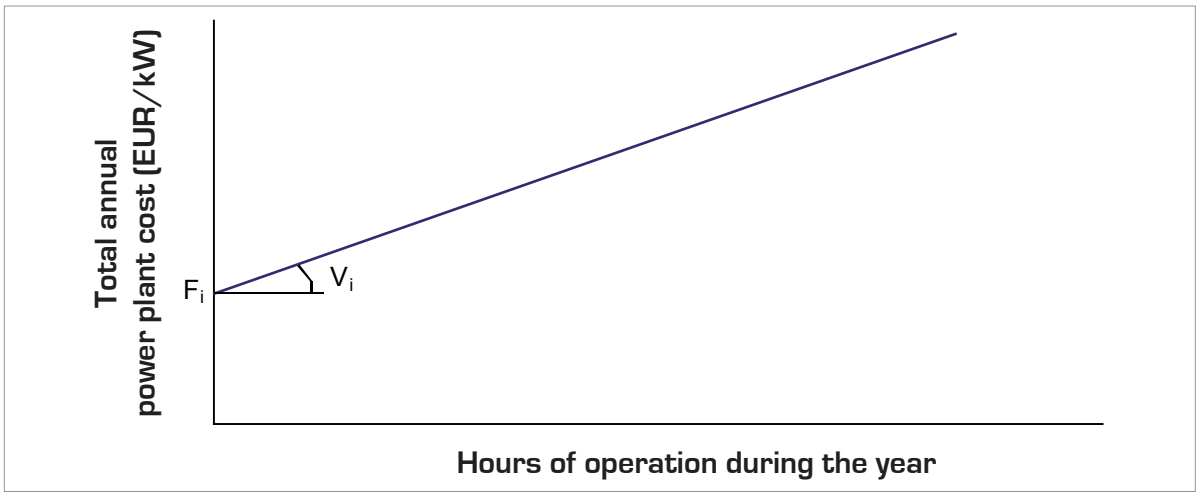

Figure 3.8: Annual cost for generating electricity per kW of installed capacity of a power plant

of future power plants need to be considered. For this reason, when very accurate results are sought, deterministic comparative methods are further expanded by probabilistic methods for treating such uncertainties.

3.4 The screening curve method

An accurate estimate of the composition of the power plant fleet that is needed to meet an anticipated peak load and a load profile is made using sophisticated but complex probabilistic simulation methods that aim to minimise the expected electricity production costs. This modelling approach, called *production cost analysis*, simulates forced outages of generation units and in turn estimates the *capacity factors*. The capacity factor is defined as the ratio of electricity generated by a power plant in a year to the maximum amount of electricity that the plant would generate if it operated at full capacity during the same period. More details on this technique and other optimisation methods can be found in the literature [14]. A prerequisite, however, for the production cost analysis is *a priori* knowledge of the technologies included in the electricity generation portfolio.

A simpler technique that can be used to estimate the technology mix is the *screening curve method*. This method combines the cost curves, as discussed in the previous section, and projections of load duration curves, discussed in Section 3.2, to provide rough estimates for the electricity generation technology mix. This method is typically implemented as the first scoping step in every detailed planning analysis, mainly to eliminate the least attractive options from further consideration and to identify the options that should be further refined through a production cost analysis.

The first step of the screening curve method entails constructing and examining the cost curves of all candidate power plant technologies. This is shown graphically in Figure 3.9. For the sake of simplicity, three types of power plant are considered in this example: a peak load (P), a load following (F) and a base load (B) plant. This graph shows that the peak load power plant generates electricity at the lowest cost among the three technologies when it operates for t_1 hours per year or less. Similarly, the base load plant power plant is the most economically attractive option when it operates for t_2 hours per year or more. Load following plants should run for more than t_1 and no more than t_2 hours in a year in order to be competitive; in practice their operating time will lie somewhere between those two time markers.

In the second step of the screening curve method the optimal temporal range of operation of each power plant type (step 1) is translated into a capacity mix. This is achieved by combining the temporal ranges resulting from Figure 3.9 with a load duration curve. This is shown in Figure 3.10. The thick lines at the top part of Figure 3.10 show the lowest-cost power plant type as a function of operating time through a calendar year. The times t_1 and t_2, that mark the ranges for the economic operation

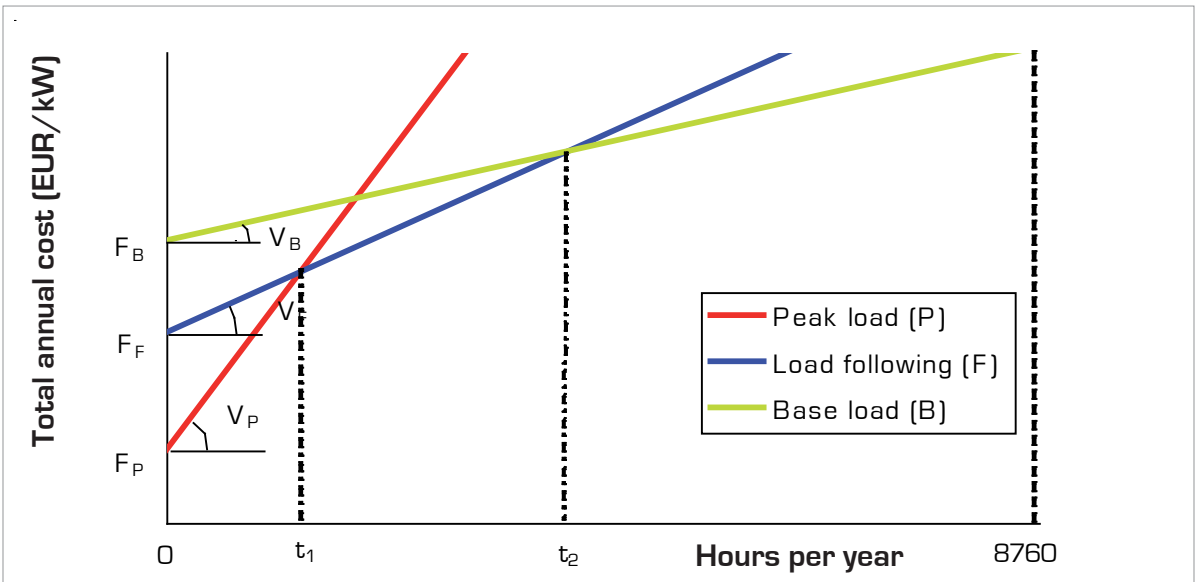

Figure 3.9: Annual costs per kW of installed capacity for three types of power plant

of each type of power plant are transposed using the load duration curve (lower part of Figure 3.10) into capacities for each type of power plant. More information on the screening curve method can be found in the relevant literature, e.g. in [14, 22-24].

The screening curve method has a number of limitations when compared to the more sophisticated production cost analysis [14].

- It assumes an ideal, monopolistic electricity market, implying a structure with a single entity with exclusive control of electricity supply, and hence on planning and price.
- It does not consider any transmission/distribution constraints.

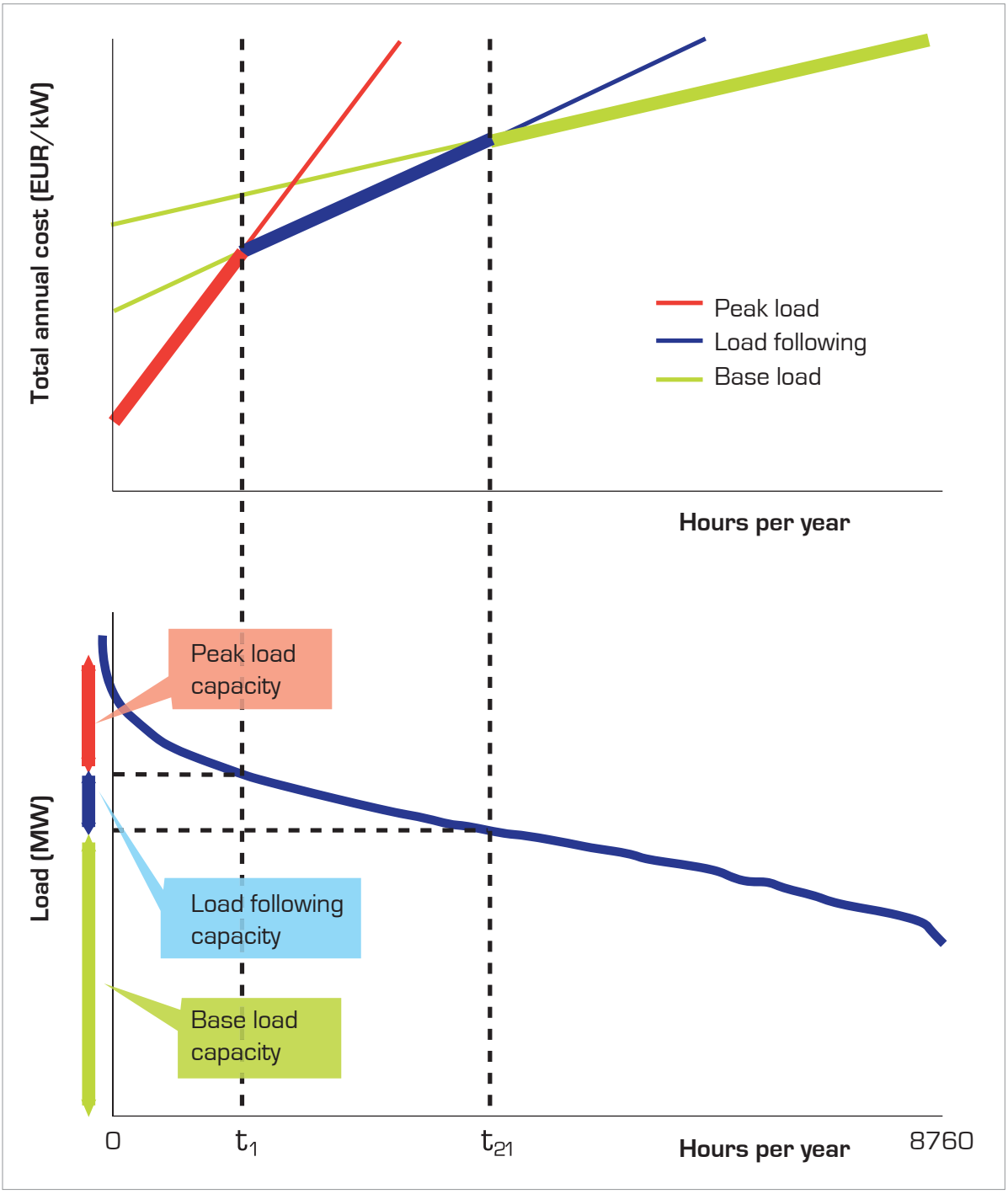

Figure 3.10: The implementation of the screening curve method

- Screening curves cannot account for scheduled or forced outages, e.g. due to maintenance, repairs, etc., or for the fluctuation in demand caused by high shares of renewable power generation integrated in to the power system This can be compensated for by considering a reserve margin, typically of the order of 15% to 20% of the peak load as mentioned previously, spread across the technologies in the electricity generation portfolio. In contrast, production cost analysis provides very accurate estimates of the cost effects by using capacity factors calculated through the application of rigorous probabilistic methods that simulate random forced outages of power plants.

- The screening curve method does not consider the size of power plant units. It is unlikely that the capacity estimates for a specific type of power plant will be an integer multiple of available unit sizes. Hence the results of the method may require some adjustments to create a portfolio of power plants with realistic sizes. Production cost analysis does not have this difficulty as it considers power plants of predefined capacity.

- There are major difficulties in treating existing capacity. The screening curve method indicates the capacity mix needed to meet demand but does not directly identify the technology mix required to fill a capacity gap existing at any given time. Procedures have been developed to accommodate existing capacity, as described in the literature [14, 22]. However, when there are two or more types of power plant in the existing capacity, the analytical implementation of the screening curve method becomes very complicated and requires the use of dedicated computational tools.

- The screening curve method is not designed to include non-conventional electricity generation options with distinctive patterns of availability, such as pumped storage or wind power.

- The screening curve method has difficulties in treating dynamic factors such as load changes, short term solutions for the technology mix, etc. These issues can only be addressed by advanced simulation techniques [14].

Despite these deficiencies, the screening curve method is a very useful tool and is widely used as the first step in every capacity planning study. It is quick, uncomplicated and allows users to determine the composition of an electricity generation technology portfolio with decent accuracy.

4 Methodology, Scenarios and Other Assumptions

This study follows the general methodology for capacity planning, as described in the previous chapter, and uses the screening curve method to estimate the composition of the future fossil fuel power plant fleet. The time horizon of the analysis is the year 2030 and the baseline is set to the year 2005. The key assumptions of the study are set out below.

- The EU[12] is treated as one control area with a monopolistic, single electricity market; this is an inherent limitation of the screening curve method. Therefore, the study does not estimate needs for new capacity at a country level.
- There are no electricity transmission constraints.
- There are no constraints on the supply of coal and natural gas, and there is no other factor influencing the composition of the electricity generation fuel mix besides the calculated composition of the power plant fleet.
- There are no technical barriers that may limit the deployment of a power plant type once the underlying technology is commercialised.
- Adequate storage capacity has been identified and made available to receive the CO_2 captured from the operation of plants with CCS.
- Centralised power generation remains the main source of electricity in Europe, implying that distributed generation does not have a significant role in covering demand.

Initially, a snapshot of the current electricity generation sector is made, which maps the operating power plants, their type and age. Subsequently, the remaining operational life of the current power plant fleet is estimated; this is needed to calculate the magnitude of the evolving gap between the anticipated capacity needs and the operational capacity of the currently installed power plant fleet in the time span of the analysis.

12 Due to the lack of sufficient detailed information for the electricity sectors of Bulgaria and Romania, this study processed information that was available for the EU-25. However, the conclusions of the study are directly applicable to the EU-27, due to the relatively small size of the power generation sectors of these two new member states of the EU.

The characteristics of electricity demand, the peak load and the load duration curves, are then estimated for the period 2005 to 2030 in five-year intervals. These are based on published literature, as the study does not attempt to produce its own European energy forecast.

The load duration curves are further treated to produce the load profile that has to be met by the fossil fuel power plant fleet. This is achieved by 'subtracting' the load that is forecasted to be supplied by RES and nuclear power plants. Two alternative cases are considered in this study for the contribution of the non-fossil fuel power plants to the European energy system: '*a business as usual (BAU) case*' and '*a low carbon policy case*', called hereafter the *policy case*, which favours RES and nuclear power plants at the expense of fossil fuel power generation.

The technical and economic characteristics of a number of power plant types are also estimated for the same period and their cost curves are calculated based on technology assessments. One of the focal points of the study is the investigation of the potential role of carbon capture and storage (CCS) in the European energy system. Hence, two different cases are examined in this study concerning the penetration of this technological option in the power sector: '*the CCS case*', which assumes that power plants with carbon capture technology are commercially ready to contribute to the power generation system from 2020 onwards; and '*the no-CCS case*', which does not consider the deployment of power plants that capture CO_2 in the European energy system within the time span of this analysis, i.e. 2030.

The study also considers three alternative cases for the development of the international prices of fossil fuels: '*a high fuel price case*', '*a medium fuel price case*' and 'a *low fuel price case*' (explained in detail below). Finally, the study considers two alternative cases for the evolution of the price of CO_2 ('*low CO_2 price case*' and '*high CO_2 price case*').

Overall, the study estimates the needs for new fossil fuel capacity and identifies the optimal power plant mix for all possible combinations of the cases mentioned above, leading to the creation of 24 alternative scenarios (summarised in Table 4.1).

Finally, the impact of the alternative power plant portfolios on Europe's energy policy targets is

assessed, using as indicators the capital investment for the construction of the needed capacity, fuel consumption, fuel mix diversity, CO_2 emissions, and the average production cost of electricity from the fossil-fuelled fleet. It should be noted that, while combined heat and power units are not explicitly mentioned or distinguished as a power generation option in this analysis, a percentage of the new installations will recover heat; and therefore all comparisons with current statistics (e.g. fuel consumption, emissions) are performed on the basis of heat and power generation.

These steps are described in detail in the following sections.

Penetration of RES and nuclear	CO_2 capture	Fuel price	CO_2 price
BAU	No	High	High
BAU	No	High	Low
BAU	No	Medium	High
BAU	No	Medium	Low
BAU	No	Low	High
BAU	No	Low	Low
BAU	Yes	High	High
BAU	Yes	High	Low
BAU	Yes	Medium	High
BAU	Yes	Medium	Low
BAU	Yes	Low	High
BAU	Yes	Low	Low
Policy	No	High	High
Policy	No	High	Low
Policy	No	Medium	High
Policy	No	Medium	Low
Policy	No	Low	High
Policy	No	Low	Low
Policy	Yes	High	High
Policy	Yes	High	Low
Policy	Yes	Medium	High
Policy	Yes	Medium	Low
Policy	Yes	Low	High
Policy	Yes	Low	Low

Table 4.1: Summary of the scenarios examined by the study

The methodology and assumptions adopted above do not refer to a liberalised industry, but rather to one where central planning is the norm. The market consists of more than one generation company in each country, and these companies are driven by commercial considerations, albeit within grid code technical agreements. These players, which will invest in future capacity, are not driven by traditional generation security standards or by national competitiveness, environmental goals or security of supply objectives. It is also important to remember that generation planning is often required to replace plants that have reached the end of their economic life. However, the lives of plants based on existing mature technologies (such as nuclear or hydro) could be prolonged beyond their nominal lifespan, especially where there are technical and/or environmental restrictions on the building of new capacity. Thus some of the important assumptions made in the study deviate from the reality of the market structures within the EU's electricity industry. Issues like the competitive nature of the market, the existence of more than one control area and the reality of significant transmission constraints to unlimited cross border electricity flows could result in distortions. So whilst the approach adopted herein is very useful in order to demonstrate broad sensitivities of investments to various background assumptions regarding fuel and CO_2 prices, it should not be viewed as a capacity planning exercise.

4.1 The current state of fossil-fuelled electricity generation in the EU

Estimating the remaining life of the currently operating fossil fuel power plant fleet is the first step in assessing the requirements for new power generating infrastructure. Such estimates, however, can only be performed when detailed information (such as capacity, construction year,

fuel and technology used) on each individual fossil fuel power plant is known in sufficient detail.

Although EUROSTAT publications, such as the Yearly Statistics [11], offer an overview of the European electricity generation sector, they do not provide the detailed disaggregated information that is required to estimate the remaining life of the currently operating fossil fuel power plants. In the context of this study this information was collected from two specialised databases, last updated in 2006: the EPIC database by Energy System Analysis and Planning SA [25], and the PowerVision utility by Platts [26]. Furthermore, for a limited number of countries additional literature and online sources have been used. It should be noted that plants owned by private producers and auto-producers have not been considered. The following information was extracted from the source databases for each power plant:

- name
- nameplate capacity
- construction year
- fuel used
- conversion technology.

This dataset was analysed to yield statistical information on the current power plant technology and fuel mix and the age distribution and decommissioning rate of plants of different types. The remaining life of the currently operating fossil fuel power plant fleet was estimated considering the age of each power plant and assuming that:

1. the technical lifetime of a steam plant is 40 years and that of a plant that uses gas turbines, including natural gas combined cycle (NGCC), is 25 years, according to standard industrial project assessment practices;
2. power plants are retired as soon as they reach the aforementioned decommissioning age and are not retrofitted to have their lifetimes extended;
3. plants that have currently exceeded their assumed retirement age are decommissioned within the next five years, i.e. by 2010.

The results of this analysis are presented in Chapter 5.

4.2 Forecasting peak loads and load duration curves

Based on the standard expansion planning methodology, peak load forecasts were deduced in this study from electricity demand forecasts and from projections of the peak load factor (see Equation 3.1 in Chapter 3). This study did not attempt to develop its own forecasts for electricity demand but adopted the corresponding values that have been presented in the baseline scenario of the 'European Energy Outlook to 2030 – 2005 Update' [12]. These values are shown in Figure 4.1. According to the European Energy Outlook, gross electricity demand will reach approximately 4 560 TWh in 2030, that is 43% higher than the current gross electricity demand (3 180 TWh in 2004 [11]).

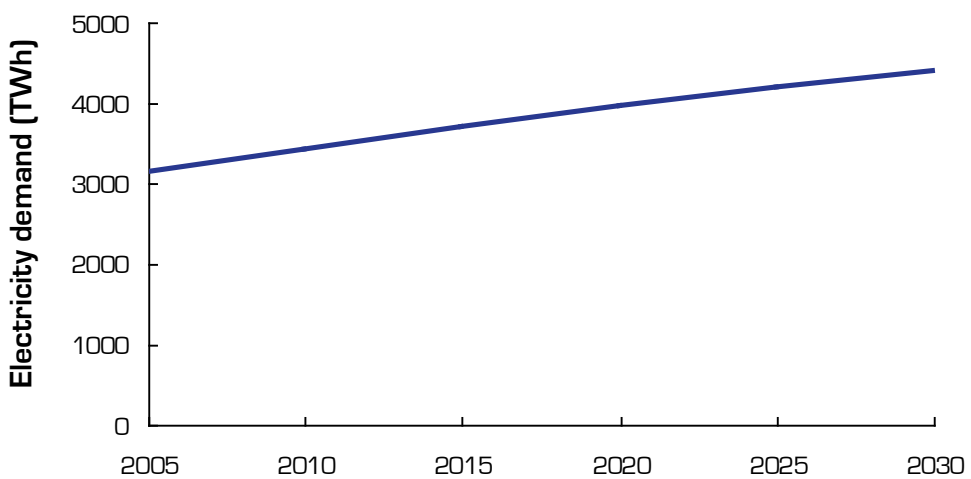

Figure 4.1: Forecast for the gross electricity demand in the EU [12]

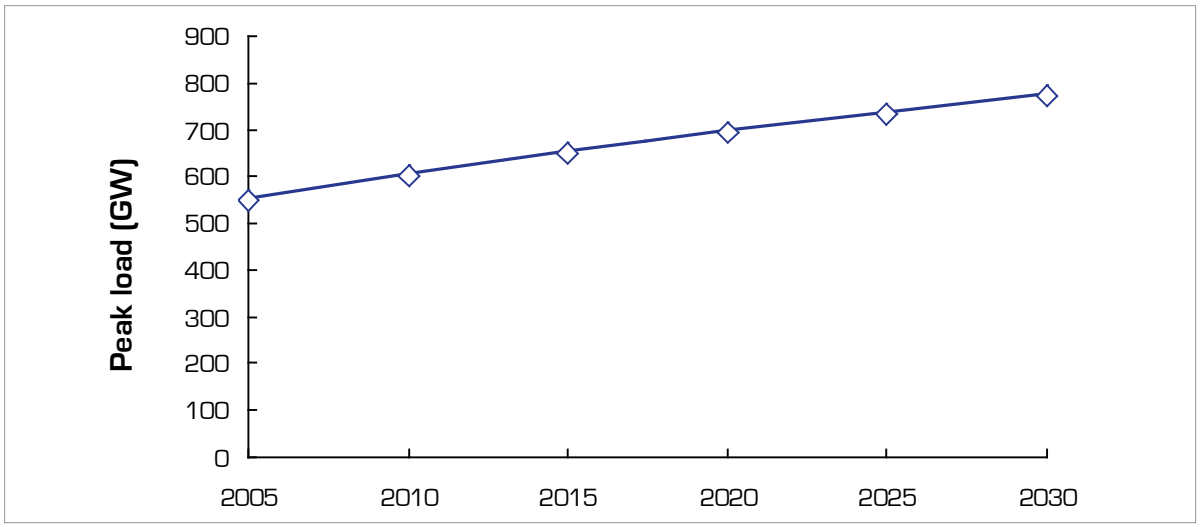

Figure 4.2: Peak load projection for the EU

Similarly, the study did not attempt to forecast the peak load factors of a pan-European electricity system. It has used the value of 0.65 throughout the time span of the planning, which is based on load factor values for many European countries, as reported in the literature [18, 27]. The resulting projection for peak load used in this study is shown in Figure 4.2.

The future load duration curves were deduced as follows: A pan-European normalised load duration curve was constructed based on actual load duration curves for a number of countries, as they appear in the relevant literature, see Figure 4.3 [28-36]. Next, it was assumed that the shape of this normalised load duration curve remains unchanged throughout the time span of the planning. Finally, the load duration curve for each year of calculation was determined by adjusting the *normalised load duration curve to the peak load for that year, Figure 4.4*.

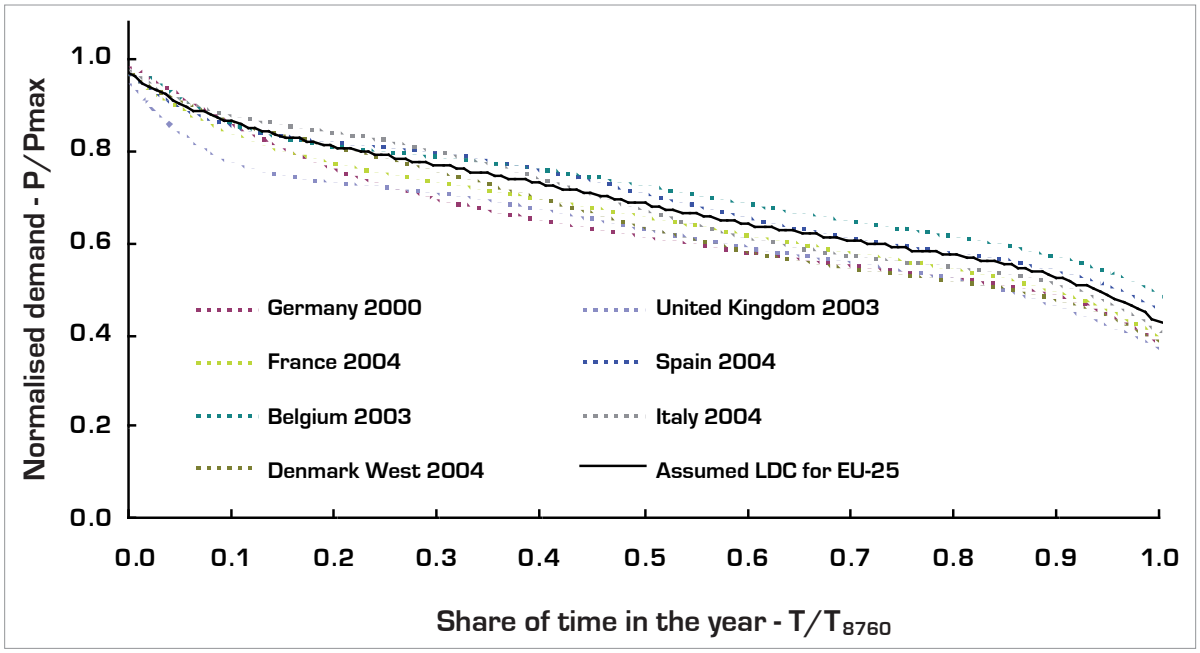

Figure 4.3: Construction of a 'pan-European' normalised load duration curve

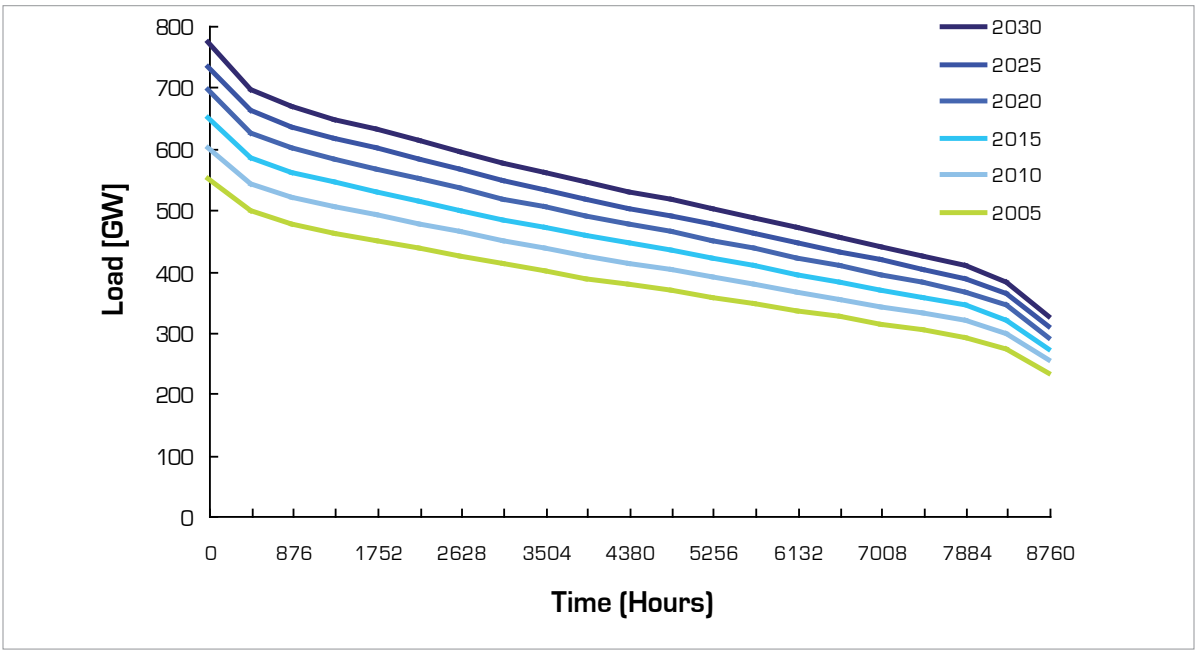

Figure 4.4: Pan-European load duration curves, assumed for the period from 2005 to 2030

4.3 Estimating the load profile of the fossil fuel power plant fleet

The forecasted demand for electricity will be met by fossil fuel power plants as well as by nuclear plants and RES. This study considers two alternative cases for the role of these non-fossil-fuel technologies in the European electricity generation system.

- The '*business as usual (BAU)*' case: In this case, RES penetration is moderate and the contribution of nuclear energy to the electricity generation mix declines. More specifically, the electricity generated by nuclear plants declines from 986 TWh in 2004 to 817 TWh in 2030 (that corresponds to 19% of the gross electricity generation that year) according to the projections for the baseline scenario in the *European Energy Outlook to 2030 – 2005 Update* [12]. Electricity generation from wind is supported at moderate levels (0.035 EUR/kWh) and increases from 94 TWh in 2005 to 495 TWh in 2030 [37]. Similarly, electricity generation from other RES (including hydro) continues to increase from 400 TWh in 2005 to 636 TWh in 2030. The latter figure is based on the projections of the FORRES 2020 study, BAU scenario [39], extrapolated to 2030 using the trend of an expansion in wind power generation assumed in this case, as calculated in [37]. Overall, the electricity generation from RES reaches 1 131 TWh in 2030 (which is equivalent to 26% of gross generation).
- The '*low carbon policy (policy)*' case: In this case nuclear energy and RES are strongly supported at the expense of fossil fuel conversion technologies, in an effort to significantly reduce GHG emissions and improve the security of energy supply. The contribution of nuclear energy increases to 1 251 TWh in 2030 (29% of gross electricity generation), in accordance with the '*new nuclear technology being accepted*' scenario of the *European Energy Outlook to 2030* [38]. Electricity generation from nuclear power plants is practically the same as in the BAU case until 2010, but increases compared to the BAU case by 28% in 2020 and by 63% in 2030. Renewable electricity generation increases at higher rates than those in the BAU case. Electricity from wind reaches 704 TWh in 2030 (receiving financial support of 0.05 EUR/kWh) [37] and electricity generation from all other forms of RES reaches 1 096 TWh in 2030, based on the results of FORRES 2020 'policy scenario' extrapolated to 2030 following the trend of expansion of wind electricity in this case [37, 39]. Overall, the contribution of RES to gross electricity generation reaches 41% in 2030.

The *energy package* recommendations are useful for putting these two cases in perspective. The Renewable Energy Roadmap [40] proposes that renewable energy sources gain a 20% share of total energy consumption by 2020. Although the Communication does not include a specific target for renewable elec-

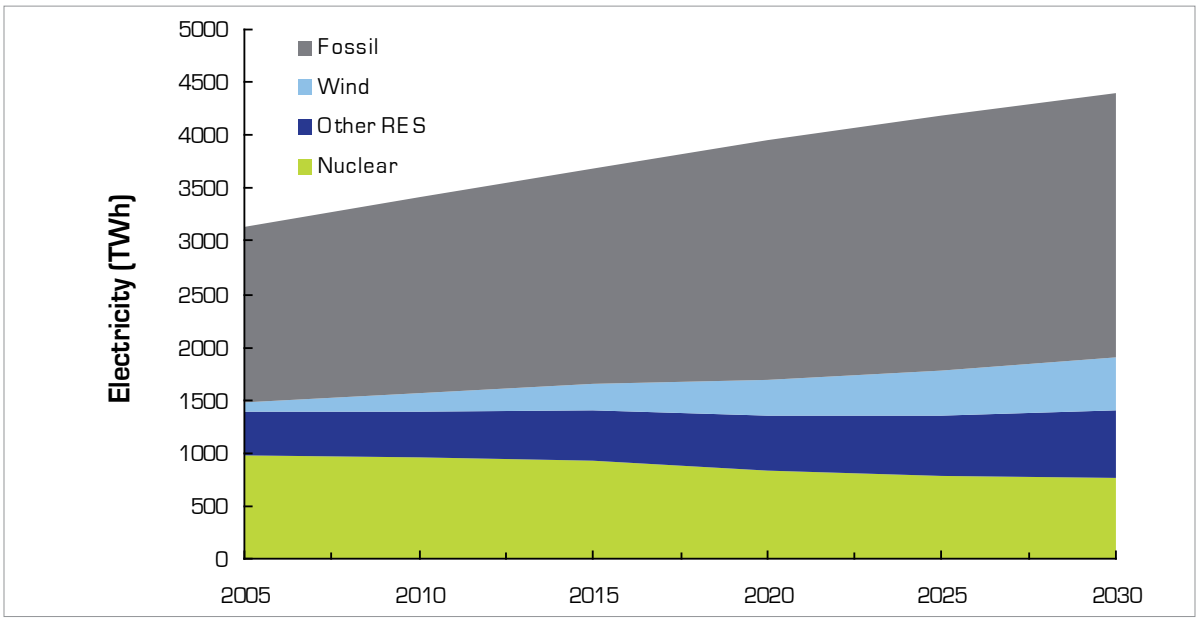

Figure 4.5: Electricity generation by energy resource in the BAU case

tricity, its annex includes a projection under which 34% electricity must be generated by RES in 2020 if the EU is to meet its targets. The corresponding shares of RES in electricity generation for the BAU and policy cases of the study for the year 2020 are 21% and 31% respectively. Hence, the projections for renewable electricity in the policy case are compatible with the new EU target concerning the promotion of the use of energy from renewable sources.

The gap between gross electricity demand and the supply from nuclear and renewable sources will be filled by electricity generated from fossil fuels. In 2005, fossil fuel power plants generated 54% of all electricity, approximately 1 700 TWh. In the *BAU case*, fossil fuel plants generate 2 500 TWh in 2030 and their share in electricity generation is 55%. In contrast, in the *policy case*, fossil fuels generate 1 300 TWh in 2030 and their contribution to electricity generation is reduced to 30%. The generation of electricity by the various energy resources is shown in Figure 4.5 and Figure 4.6 for the BAU and policy cases respectively.

In this analysis it is further assumed that nuclear and renewable electricity generation units run

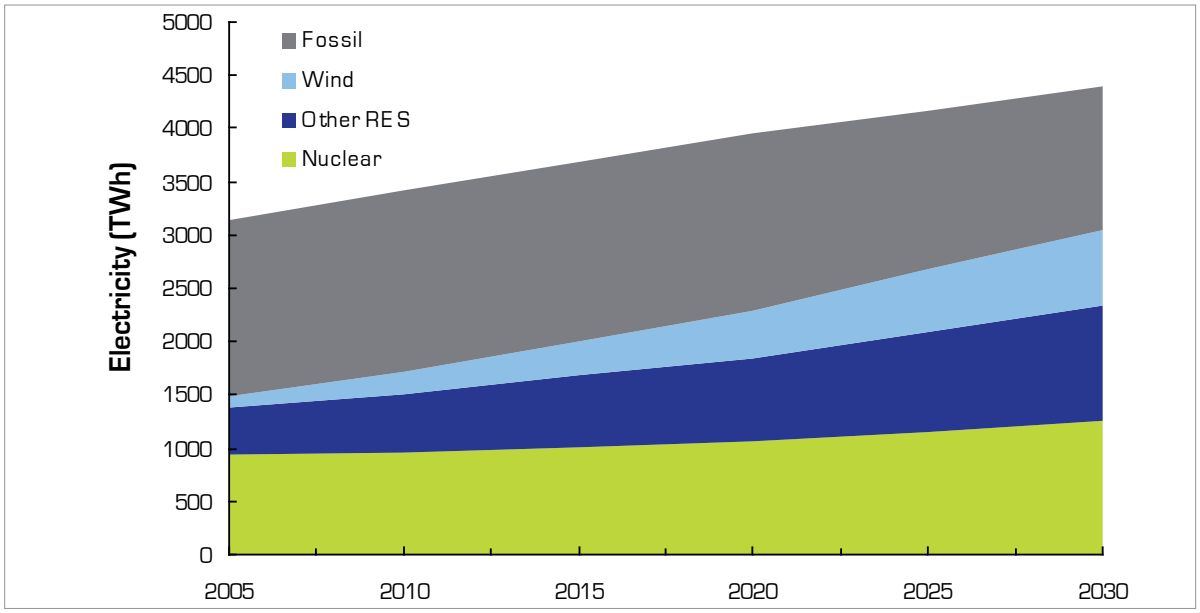

Figure 4.6: Electricity generation by energy resource in the policy case

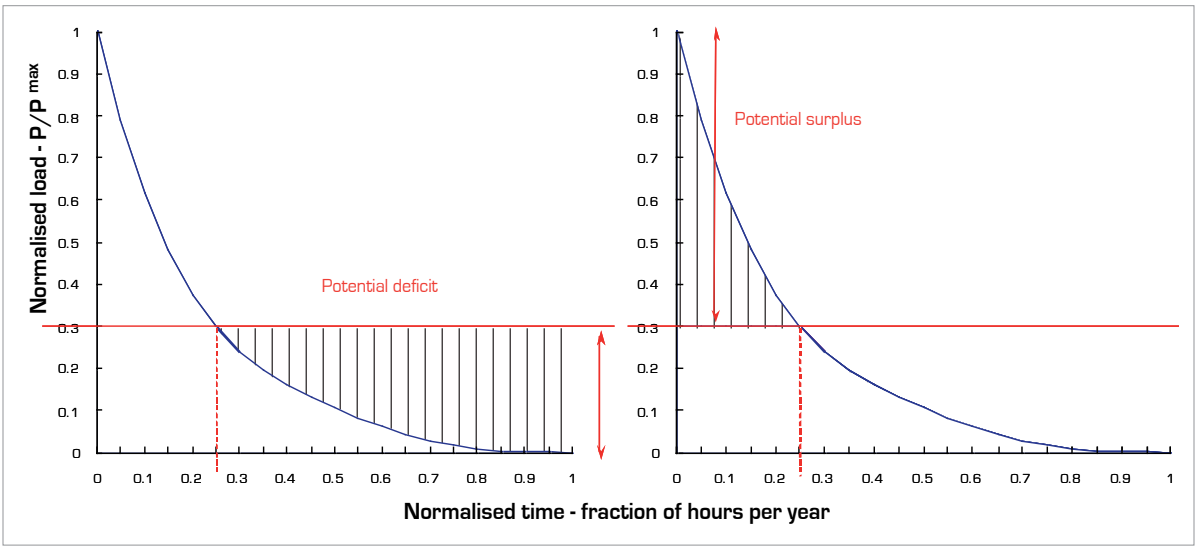

Figure 4.7: Approximation of the normalised wind duration curve and potential power 'surplus' or 'deficit' compared to the assumption of constant power output made in the study [37].

continuously throughout the year, in a base load mode. Electricity from other RES, such as hydropower, solar and biomass, is also treated as base load. This is true for nuclear plants which are not flexible and must operate continuously, although in practice they can vary their power output to some extent. Wind electricity generation is, however, intermittent, depending on weather conditions. In this study, wind power is considered as base load also, with a capacity factor of 0.3 based on average values reported in the literature, since it is extremely complicated to consider the temporal character of stochastically variable wind power for long term planning. In other words, it has been assumed that wind farms have a constant output of 30% of their installed wind power capacity at any given time.

However, the power output of wind turbines depends on location and varies with time due to changes in the wind speed. The statistical distribution of the variation in power output over a certain period of time can be presented using the wind power duration curve. The slope of the curve is a measure of variation; the steeper the slope, the less constant the power output. The steepness of the slope in wind power duration curves decreases when aggregated over larger areas and periods of time. In other words, the wind power duration curve for a park of wind turbines is smoother than that of a single turbine, etc. Taking into account the fact that this study considers wind power output across the EU, Figure 4.7 shows an approximation of a normalised duration curve for wind power output, marking also the output considered in the study and the possible deviation from this value.

The surplus wind output can replace 'flexible' capacity – here taken to be fossil-fuelled as it is assumed that the renewables have priority dispatch – but at the same time there should be enough flexible capacity to cover the 'deficit'. For about 75% of the year there could be a need to cover a load of up to 30% of the installed wind capacity. The maximum deficit could range from 11 GW to 61 GW for the years 2005 to 2030 respectively in the BAU case, while in the policy case the gap could be 14 GW to 85 GW for the same time period. Similarly, because of the priority given to renewable energy, there could be a need to reduce the output of 'flexible' capacity for up to 25% of the year because the available output from wind power is greater than the average assumption. In this case there is an extra 25 GW to 143 GW available in the BAU case, and 32 GW to 197 GW available in the policy case for the same time period.

By assuming that the non-fossil fuel power plants get dispatch priority among all electricity generation units, the load profile that needs to be followed by the fossil fuel plant fleet is calculated by subtracting the electricity generated by non-fossil fuel plants from the annual load duration curve; for an example see Figure 4.8.

The 'fossil fuel load duration curves' for the two cases (*BAU* and *policy*) are shown in Figure 4.9 and Figure 4.10. It is interesting to note that for the year 2030 in the *policy* case, the penetration of the non-fossil fuel power generation technologies is so significant that at certain times of the year there is no demand for fossil fuel generated electricity.

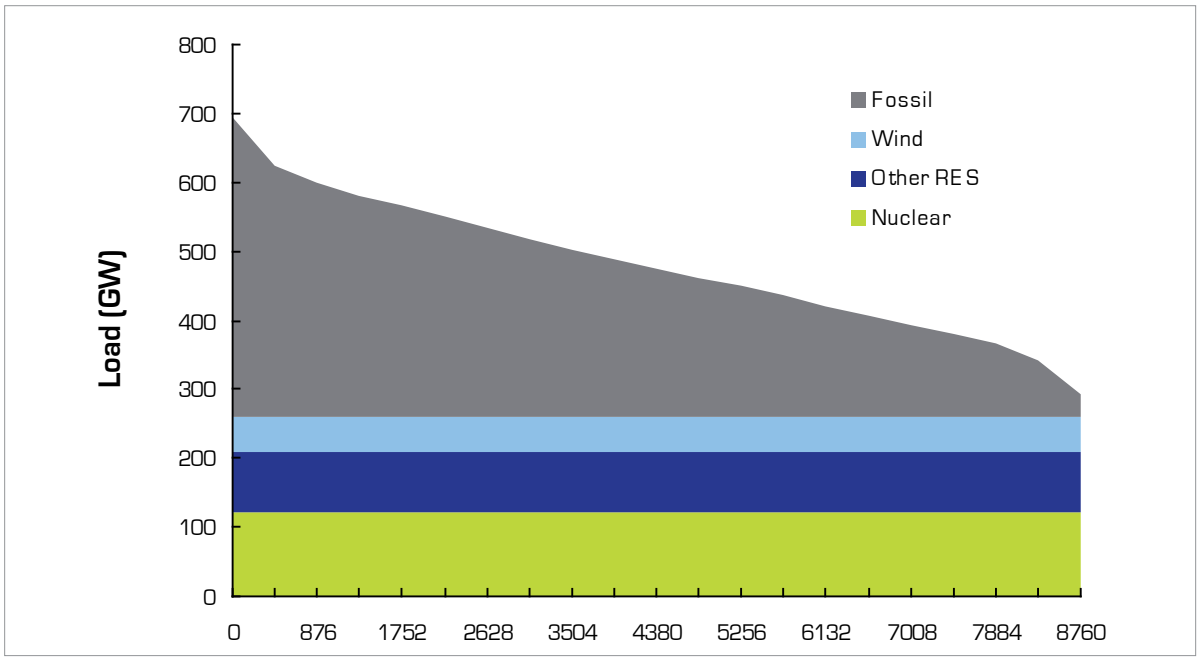

Figure 4.8: The contribution of power generation technologies, grouped by energy resource, in meeting the electricity demand in 2020 in the policy case.

4.4 Techno-economic assessment of fossil fuel power plants

A number of commercialised fossil fuel power plant technologies will compete to participate in the future electricity generation sector: pulverised coal plants, natural gas combined cycle plants and oil-fired plants, mainly for base-load and load following operations; and gas turbines and internal combustion reciprocating engines to meet the peak load. Each of these technology options comes in a range of configurations with distinctive performance and cost characteristics. For example, pulverised coal plants are available with sub-critical, supercritical or ultra supercritical boilers. Moreover, most of these plant types can operate with hard coal or lignite and the performance and costs of each design also depend, among other factors, on the size of the plant. This variability in plant configurations makes it practically impossible

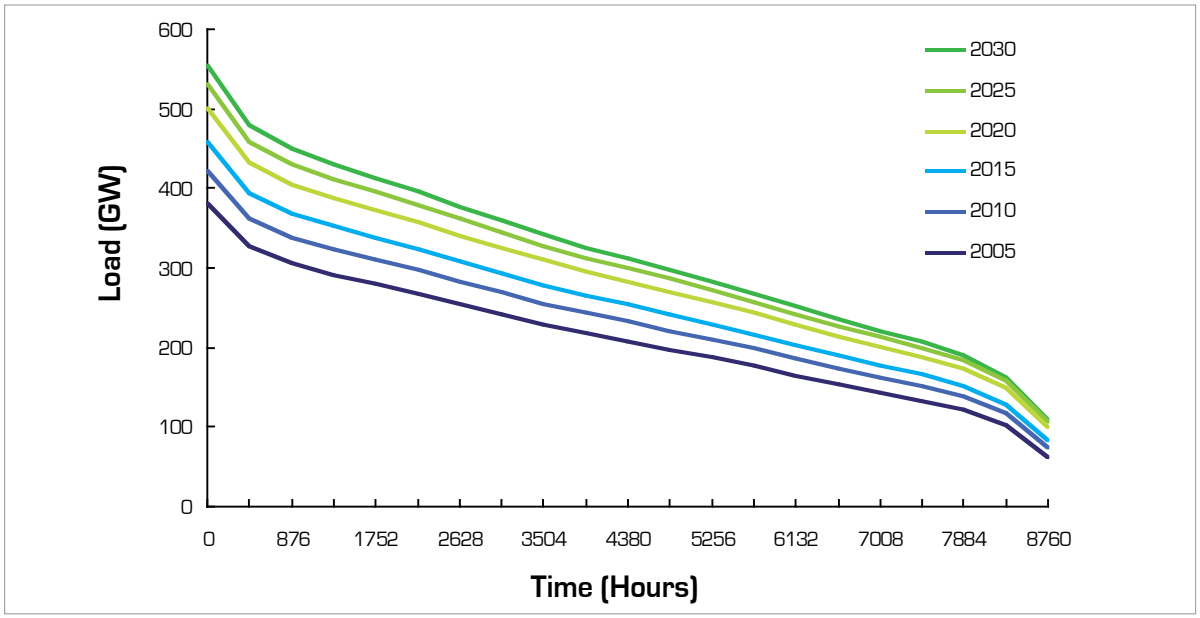

Figure 4.9: Load duration curves for the fossil fuel power plant fleet in the BAU case

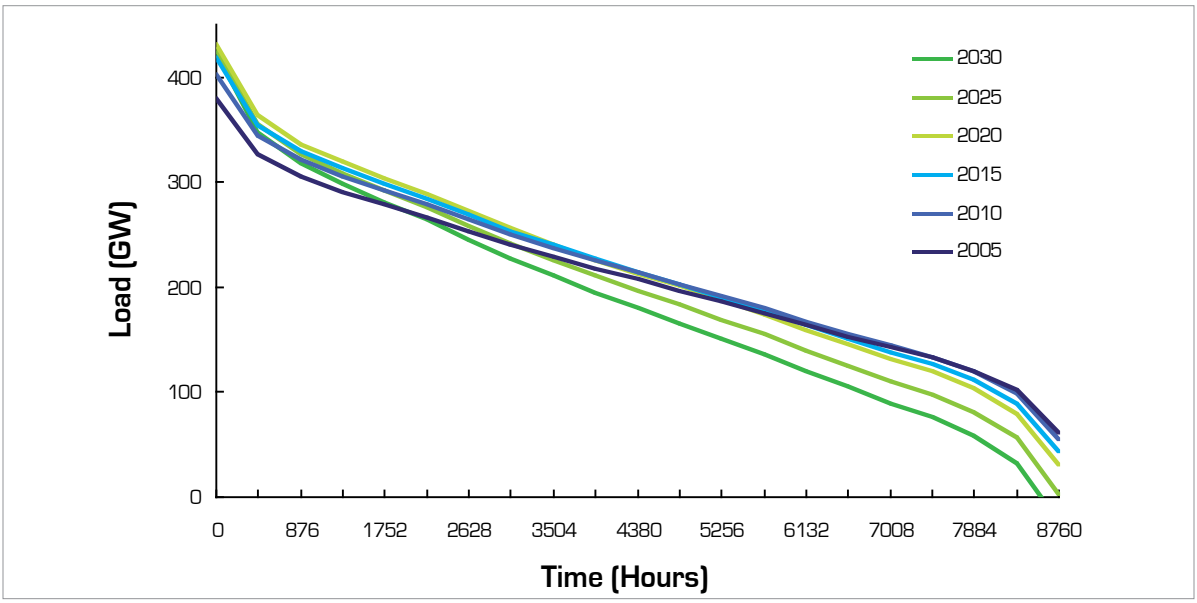

Figure 4.10: Load duration curves for fossil-fuel power-plant fleet in the policy case

to consider them all in this analysis. To simplify the calculations, only a limited number of technologies have been considered in this study. Lignite plants, oil-fired plants and internal combustion reciprocating engines have not been considered. Obviously, a fraction of the new coal capacity will be fuelled by lignite; and a fraction of the capacity allocated to open cycle gas turbines will be taken over by internal combustion reciprocating engines, for example in areas without access to natural gas.

In an effort to reduce greenhouse gas emissions from the energy sector, Europe is currently developing carbon capture technologies for power plants. According to the vision of the Zero Emissions Fossil Fuel Power Plant Technology Platform, such near-zero emission fossil fuel power plants will be commercialised by 2020, with the first-of-the-kind plants becoming operational as early as 2015 [41]. To examine the impact of CCS technologies, this study considers two alternative cases.

- The '*No CCS case*', where the CCS technology is not commercialised. This could be the result of unsuccessful or insufficient research efforts to demonstrate the technology, negative public reaction driven by concerns over the safety of CO_2 storage, the absence of an effective regulatory framework, etc. In this case the following power plant technologies are considered in the analysis:
  1. supercritical pulverised coal plants (PC),
  2. combined cycle natural gas plants (NGCC),
  3. natural gas open cycle turbines (GT).
- The '*CCS case*', where power plants that capture CO_2, with a capture efficiency of 90% could start being deployed on a commercial scale from 2015 to 2020 onwards. In this case, the types of power plant considered are:
  1. those in the 'No CCS case',
  2. supercritical coal plants with post-combustion capture (PC CCS),
  3. natural gas combined cycle plants with post-combustion capture (NGCC CCS),
  4. integrated gasification combined cycle plants with pre-combustion capture (IGCC CCS).

The values for efficiency[13], the specific SCI that includes the owner's costs, FOM and VOM (excluding fuel costs) that are assumed for the state-of-the-art of the various power plant types are shown in Table 4.2. The economic lifetime of the plants is set to 25 years and a discount rate of 10% is assumed.

13 The figure refers to maximum attainable efficiency per technology when operating under optimal conditions.

	2005-2010	2010-2015	2015-2020	2020-2025	2025-2030
Pulverised coal					
Efficiency (%)	45.0	46.0	47.0	48.0	49.0
SCI (EUR/kW)	1245	1185	1125	1070	1015
VOM (EUR/MWh)	1.00	1.00	1.00	1.00	1.00
FOM (EUR/kW)	25.2	25.2	25.2	25.2	25.2
Pulverised coal with capture					
Efficiency (%)			33.0	35.0	37.0
SCI (EUR/kW)			1750	1630	1520
VOM (EUR/MWh)			3.10	3.00	2.90
FOM (EUR/kW)			60.7	59.0	57.3
IGCC with capture					
Efficiency (%)			35.0	37.0	39.0
SCI (EUR/kW)			1675	1510	1360
VOM (EUR/MWh)			1.25	1.15	1.00
FOM (EUR/kW)			66.0	59.4	53.5
Natural gas combined cycle					
Efficiency (%)	56.5	57.0	58.0	59.0	60.0
SCI (EUR/kW)	640	610	580	550	520
VOM (EUR/MWh)	0.30	0.30	0.30	0.30	0.30
FOM (EUR/kW)	26.0	26.0	26.0	26.0	26.0
Natural gas combined cycle with capture					
Efficiency (%)			48.0	50.0	52.0
SCI (EUR/kW)			970	900	840
VOM (EUR/MWh)			0.63	0.60	0.57
FOM (EUR/kW)			38.0	37.0	34.0
Open cycle gas turbine					
Efficiency (%)	35.0	35.0	35.5	36.0	36.5
SCI (EUR/kW)	340	330	320	315	310
VOM (EUR/MWh)	2.70	2.70	2.70	2.70	2.70
FOM (EUR/kW)	10.0	10.0	10.0	10.0	10.0

Table 4.2: Efficiency and cost characteristics of state-of-the-art power plants

These values were calculated as set out below.

Plants without capture

- The baseline (2005-10) values for the pulverised coal and the natural gas combined cycle plant are based on the experience of European utilities and those for the open cycle gas turbine come from manufacturer information fact sheets.
- The efficiency of new PC and NGCC plants is assumed to increase by 1 percentage point every five years and that of new GT by 0.5 percentage points every five years.
- The SCI for all new plants is reduced by 5% every five years.
- The FOM and VOM costs for all plants remain constant throughout the time span of the analysis.

Plants with carbon capture

- The efficiency of new power plants with capture for the period from 2015 to 2020 is taken from the IPCC report on carbon capture and storage [42], and for plants built in subsequent years it is assumed to increase by two percentage points every five years.
- The SCI for the new PC CCS and NGCC CCS plants in 2020 is calculated by multiplying the SCI ratio for plants with and without capture from the IPCC report [42] with the SCI of the plant without capture as calculated above. It is further assumed that the capital costs of the conventional part of the new power plant decline by 5% every five years, as do the costs of the same type of plant without capture. The incremental capital costs of the capture part of the plant are expected to decrease by 10% every five years.
- The SCI for the IGCC plants built by 2020 is adopted from [43] and is assumed to decrease by 10% every five years for new plants built thereafter.
- The VOM and FOM for the new PC CCS and NGCC CCS plants for 2020 are adopted from an assessment by the IEA GHG Programme [44]. These costs comprise the costs of the reference plant (i.e. the parts of the plant that are identical to those of a similar plant that does not capture CO_2) and the costs for the capture part of the plant. The costs for the reference plant are set so that they are equal to those of the same type of new plant without capture for the same period and the same nominal capacity while those for the capture part of the plant are assumed to decrease by 5% every five years for plants built thereafter.
- The VOM and FOM for the IGCC plant in 2020 are adopted from [44] and are assumed to decrease by 10% every five years for plants built after that period.

4.5 Completing the cost curves: Fuel and CO_2 prices

Fuel and CO_2 prices have a significant impact on the operating costs of power plants and hence play a key role in the power plant technology selection process. Projections indicate that the price of natural gas, as long as it is linked to oil prices, will continue to increase in the future. Moreover, analyses indicate that the price of coal is also likely to rise, although the magnitude of this price change is difficult to forecast. Finally, the market for CO_2 is still in its infancy, and it is unclear how it will develop in the mid and long term. To address the uncertainty of future fuel and CO_2 prices, and in view of the importance of these factors in the electricity generation expansion process, this study considers a number of cases for their evolution.

4.5.1 Cases for the evolution of coal and natural gas prices

The scenarios concerning the evolution of fossil fuel prices (oil, natural gas and coal) considered in this analysis are:

1. the 2005 update of the 'Energy Outlook to 2030', published by the European Commission [12];
2. the WETO-H_2 study, co-funded by the European Commission [45];
3. the 2006 World Energy Outlook published by the IEA [46].

The prices for natural gas and coal from the aforementioned analyses have been converted to

2005 euros using average US dollar-to-euro conversion rates as reported by international banks and inflation rates as reported by EUROSTAT for that year[14]. Figure 4.11 shows the evolution of the prices of natural gas and coal per energy content (GJ) and the price of oil in US dollars per barrel.

From Figure 4.11 it is evident that all three studies predict a similar trend for the evolution of fossil fuel prices. Both natural gas and coal prices will increase, with the rate of the price rise for natural gas exceeding that of coal. While the trends are similar, the absolute price forecasts emanating from these studies for each fuel as a function of time are quite different. IEA values are the most conservative; those from WETO-H_2 are the highest after 2015; and those of the Energy Outlook lie in between. In view of this range in reported fuel prices, this study considers the following three cases:

- the '*low coal and gas prices*' (or '*low price*') case, adopting the values reported by IEA [46];
- the '*high coal and gas prices*' (or '*high price*') case, adopting the values from WETO-H_2 [45];
- the '*medium coal and gas prices*' (or '*medium price*') case, adopting the values from the updated Energy Outlook [12].

For all scenarios, a common starting point is assumed for the year 2005, with fuel prices for coal and natural gas of EUR 1.5/GJ and EUR 4.0/GJ respectively. These values represent the actual average fuel prices for that year.

The range of prices for coal and natural gas considered in the study is shown in Figure 4.12, while the ratio of the natural gas price to the coal price for each price case is shown in Figure 4.13. The average ratios of the natural gas price to the coal price over the time frame of the study are 2.44, 2.71 and 2.80 for the *low-*, *medium-* and *high*-price cases respectively.

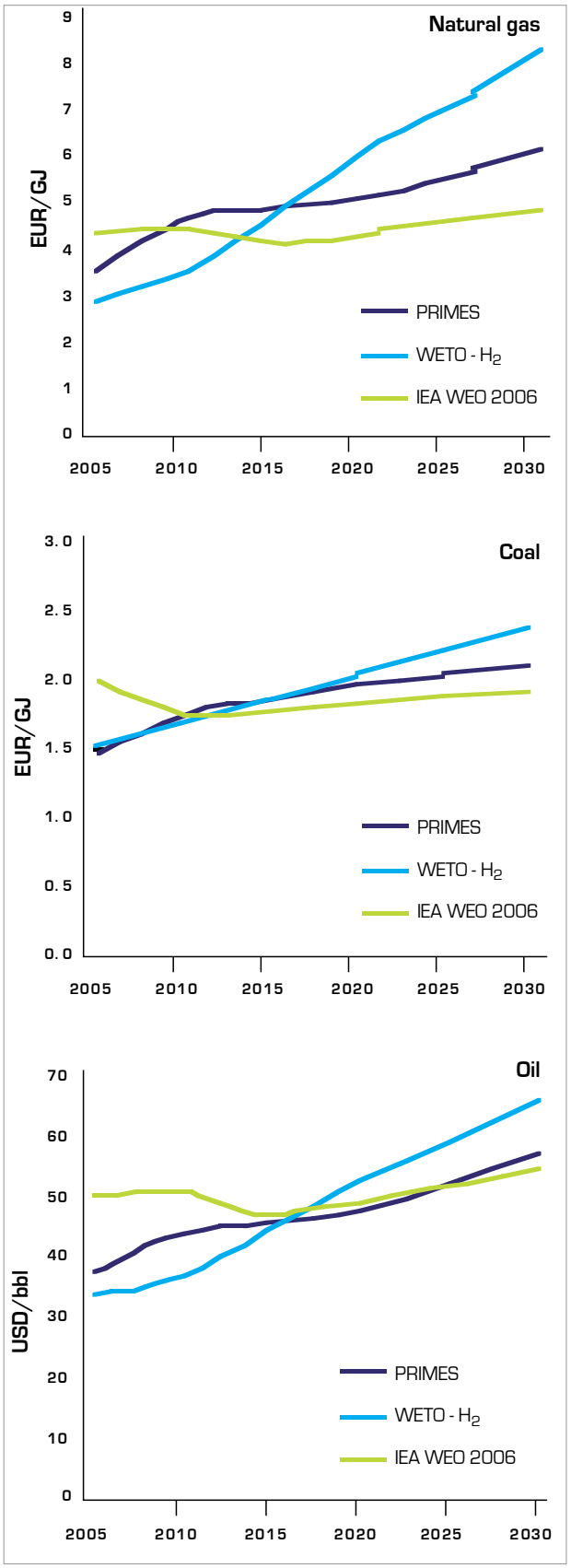

Figure 4.11: Fuel price projections made by different studies for natural gas, coal and oil [12, 45, 46]

14 The annual exchange rate for 2005 according to EUROSTAT is EUR 1 = USD 1.2441.

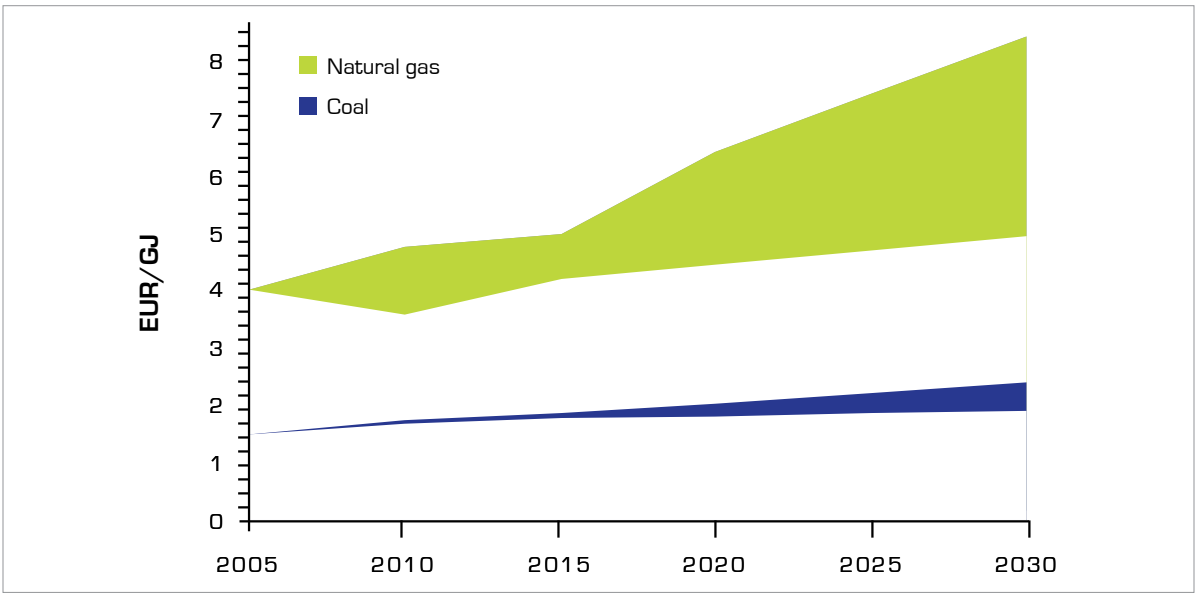

Figure 4.12: The highlighted areas show the expected upper and lower limits assumed for the price of these fuels for the time span of the analysis [12, 45, 46].

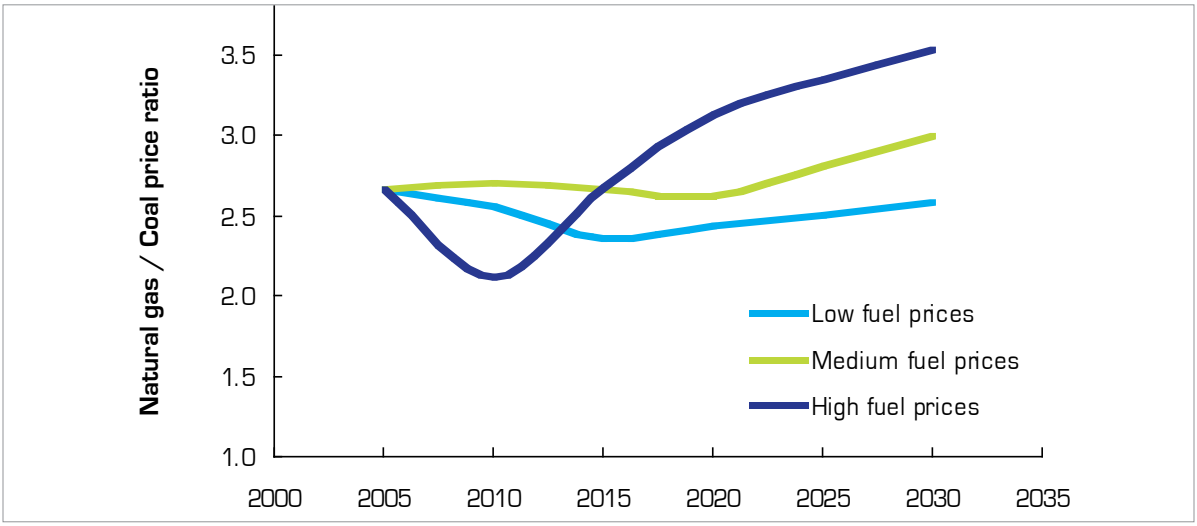

Figure 4.13: Ratios of natural gas to coal fuel prices for each fuel case considered in the study [12, 45, 46].

4.5.2 The cost of CO_2 emissions

The study assumes that power plants pay a penalty (that could be a tax or a permit) for each tonne of CO_2 emitted[15]. This CO_2 price is exogenous, i.e. it is not calculated but rather provided as an input for the analysis.

Following an approach similar to that used for the price of fuels, this study does not attempt to predict the evolution of CO_2 prices but relies on published literature, namely the WETO-H_2 study, [45] and considers two cases for the price of CO_2.

- The '*low carbon price*' case that corresponds to the Reference Case of the WETO-H_2 analysis. This case represents the minimum climate policies that could be developed in the EU. A carbon value of EUR 5/t CO_2 is assumed for 2005, rising to EUR 20/t in 2030.
- The '*high carbon price*' case that corresponds to the Carbon Constrained Case of the WETO-H_2 analysis. This case reflects the application of stringent emissions constraints. The CO_2 value in the EU up to 2010 is the same as in the *low carbon price* case, and from that point on it increases linearly to EUR 105 /t in 2030.

15 Captured CO_2 is not considered to have been emitted.

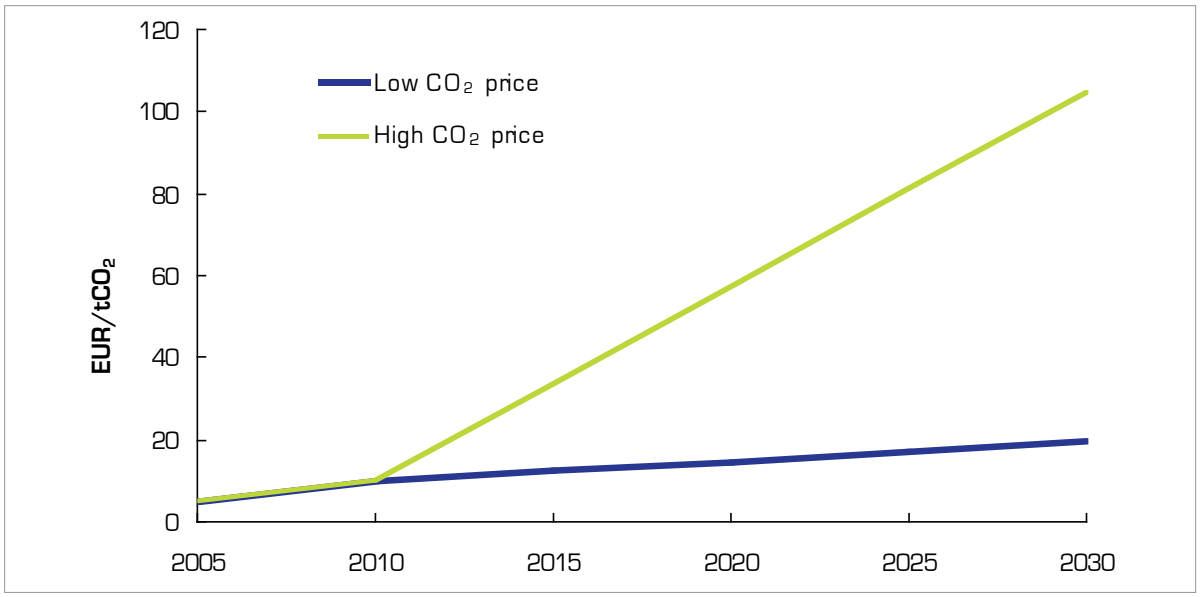

Figure 4.14: CO2 prices considered in the analysis, adopted from [45]

The evolution of the CO_2 price in these two cases is depicted in Figure 4.14.

Finally, in the case of CCS deployment, a cost of EUR 5 is paid for each tonne of CO_2 captured to account for its transport and storage.

4.6 Steps in the application of the screening curve method

The new power generation capacity required and the optimum technology mix for each five-year interval (Y_{N-4} – Y_N) is calculated according to the following steps.

1. The cost curves are drawn considering the state-of-the-art of each technology in the period Y_{N-4} to Y_N (Table 4.2) and the corresponding fuel and CO_2 prices in Y_N (Figure 4.12 and Figure 4.14).

2. The theoretical required capacity and the annual operating time for each technology are calculated by applying the screening curve method and using the load duration curve that corresponds to Y_N (Figure 4.9 and Figure 4.10).

3. An operating reserve margin equal to 20% of the peak load shown in Figure 4.4 is assumed. The resulting additional capacity is distributed proportionally to the technologies identified in step 2 according to their participation in the capacity mix as calculated by the screening curve, and is added to the theoretical requirements estimated in the previous step.

4. In the case of open cycle gas turbines, assumed to exclusively cover peak load, the calculated required capacity is compared to that already installed. The additional gas turbine capacity that needs to be constructed is set as being equal to the difference between the two.

5. The required capacity for all other technologies (that operate in base-load and load-following mode) is compared to the capacity already in place (minus the open cycle gas turbines) to determine the capacity gap. Any shortage in capacity is met by the construction of new capacity as follows (refer to Figure 4.15):

    a. the dominant base load technology (A) is identified and the already installed capacity for that technology is compared to the capacity level suggested by the screening curve;

    b. if the suggested capacity is greater than the capacity in place then technology (A) contributes to the build-up of the new capacity by that difference;

c. if the already installed capacity of technology (A) is greater than the capacity needs calculated by the screening curve for this technology, then the process is repeated for the next technology (B),

d. the procedure is repeated in turn with all available technologies (here A, B and C), until the overall capacity gap is filled by the introduction of new capacity;

e. finally, it is assumed that the new capacity, calculated for the five year interval, is deployed gradually throughout the five-year period.

Details on the currently operating capacity for each of the technologies considered in the study are given in Chapter 5.

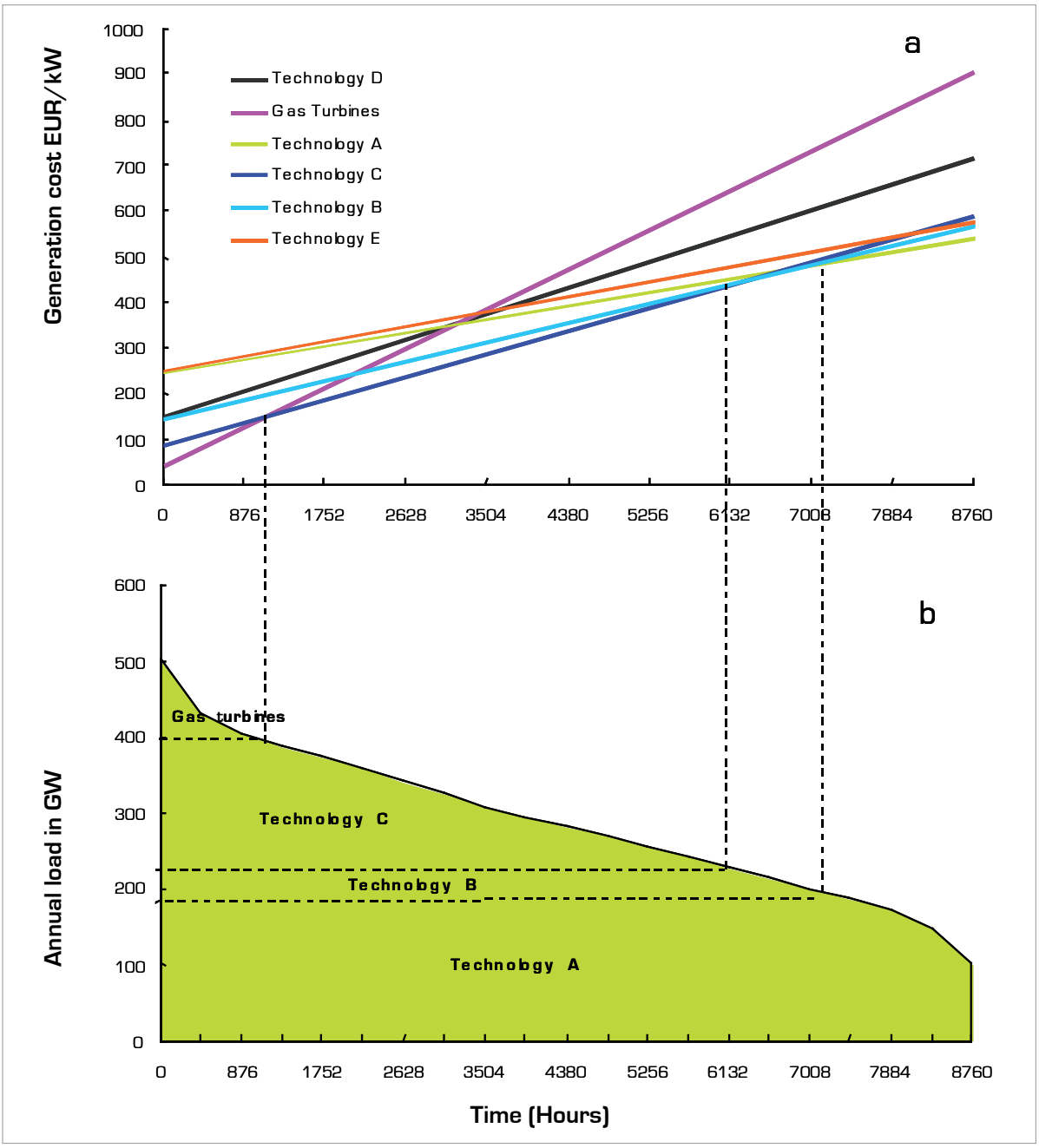

Figure 4.15: Example of the implementation of the screening curve method.

When the above algorithm is used, the ideal capacity mix as suggested by the screening curve method is not always achieved as the most competitive technologies at the time are only allowed to penetrate the power plant fleet to the point that the capacity gap is filled. In other words, operational capacity is not replaced before it reaches its retiring age, even if the screening curve method indicates that there are alternative technologies that could generate electricity at a lower cost[16].

The requirements for new capacity and the resulting technology mix are presented in Chapter 6 for the *BAU* case and in Chapter 7 for the *policy* case.

4.7 Impact Assessment

4.7.1 Overnight capital investment

The overnight capital investment required in each five-year period is calculated by multiplying the new capacity requirements for that period with the respective specific capital investment costs reported in Table 4.2. It is further assumed that the expenditure is spread uniformly over the five-year period. The resulting capital investment figures for the different scenarios are presented in Sections 6.2 and 7.2 for the *BAU* and the *policy* cases respectively.

4.7.2 Electricity generation

Calculating fuel consumption and CO_2 emissions from the fossil fuel power plant fleet involves estimating the electricity output from each type of power plant participating in the capacity mix. The electricity generated by each technology is represented by the surface area bound by the load duration curve and the load axis in the load duration curve diagram (as marked for example in Figure 4.16 for technology C). Calculating the respective area for each technology provides a theoretical optimum electricity output for each technology that should correspond to the ideal capacity mix resulting from the application of the screening curve method. However, as previously discussed, the technologies that are most competitive at the time are only allowed to penetrate the power plant fleet to fill the capacity gap, resulting in an actual capacity mix different from the one suggested by the screening curve. Thus the calculated electricity output has to be attributed to the technologies actually present. This is done as follows.

1. The electricity generated by each technology according to the screening curve method is determined by calculating the respective area marked on the load duration curve (see example in Figure 4.16 for technology C).

2. In the case of open cycle gas turbines this is the net electricity generation.

3. For each of the other technologies, the capacity present (assuming an availability of 85%) is compared to the capacity requirement suggested by the screening curve method.

4. If there is sufficient capacity available, the electricity output calculated by the screening curve method is also assumed to be the actual output.

5. In the case of a capacity deficit, the electricity output for the technology in question is reduced proportionally to the capacity contribution. For example, if the actual capacity of a certain technology is half of the capacity suggested by the screening curve, then half of the electricity output calculated by the screening curve will be attributed to the technology in question.

6. Electricity output that cannot be fulfilled by the technology suggested by the screening curve due to a capacity deficit is attributed to the technologies with excess capacity. In doing so, priority is given sequentially to the technology with the most similar techno-economic characteristics. For example, if technology A in Figure 4.16 could not generate all the electricity suggested by the graph, and both technologies B and C have excess capacity, then priority would be given to technology B.

16 In reality, plants can be retrofitted to allow the burning of different fuels during their lifetime, e.g. as in the 1980s and 1990s when many coal plants were converted to natural gas to reduce SO_x and NO_x emissions.

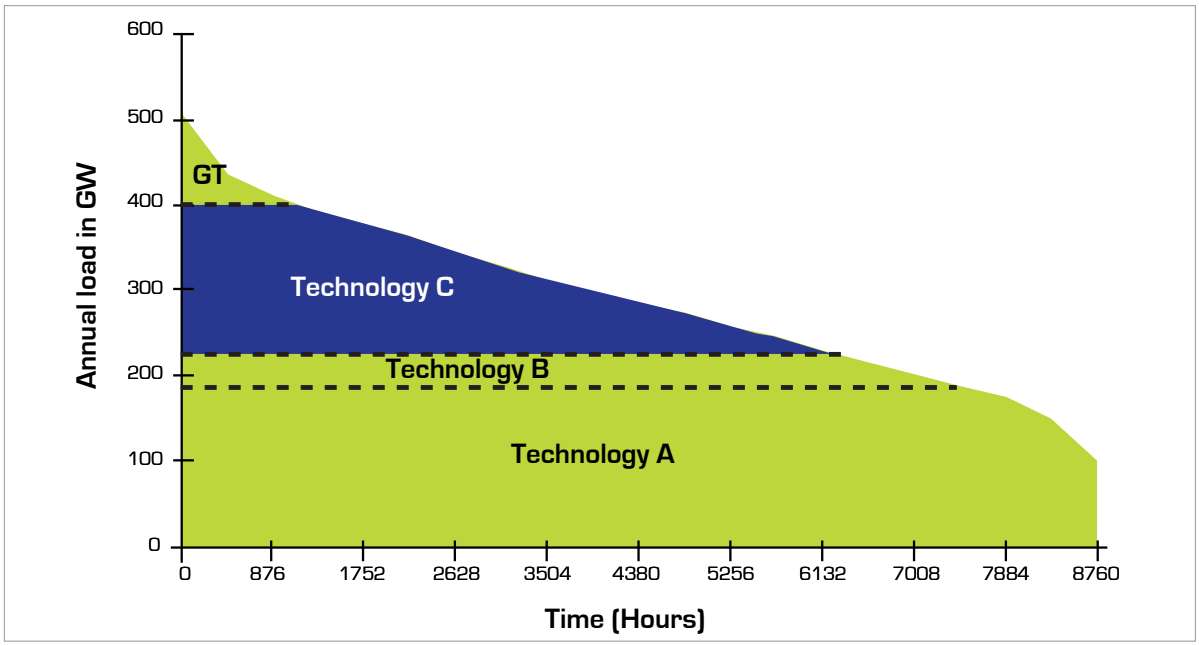

Figure 4.16: Representation of the electricity output for technology C.

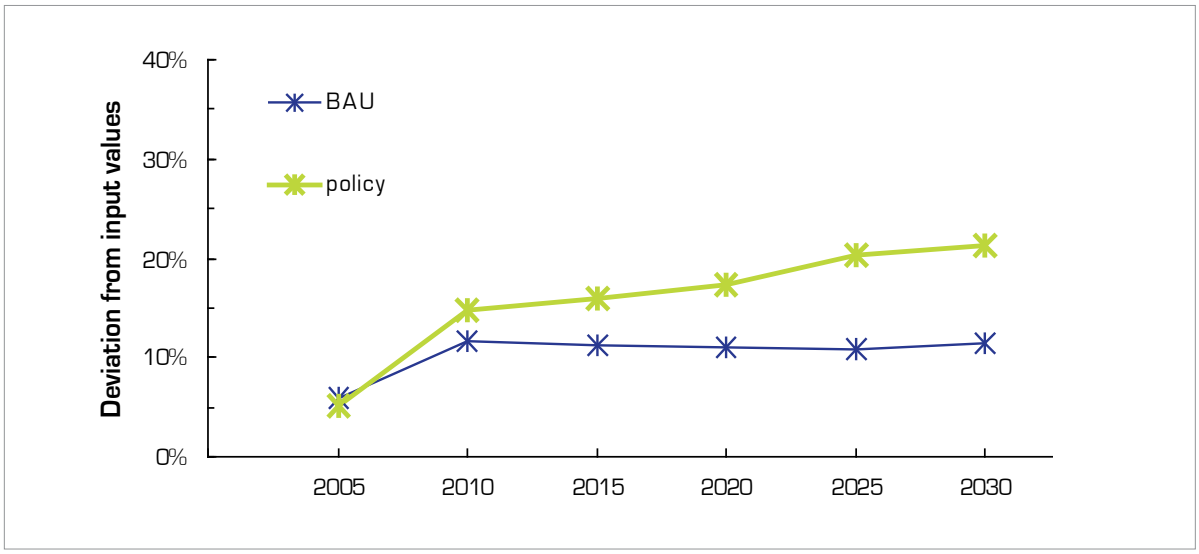

Figure 4.17: Deviation of calculated electricity generation figures from the input values for the BAU and policy cases.

As discussed in Sections 3.2.2 and 3.4, there are shortcomings in the screening curve methodology which reduce the accuracy of the results. One of the deviations caused by these shortcomings is the fact that the electricity demand calculated from the area bound by the load duration curve exceeds the initial electricity demand forecast shown in Figure 4.1. For the base year 2005, both the BAU and policy cases are within 5% to 6% of the forecasted gross electricity generation. The deviation from forecasted values is greater for subsequent years; in the order of 10% to 12% in the *BAU case* and 15% to 21% in the *policy case* (Figure 4.17). This deviation is however acceptable for the scope of this study. Moreover, as the deviation is more or less constant for the period from 2010 to 2030, the general trends of the indicators calculated will not be significantly influenced[17].

17 It should be noted that the 2005 input values for electricity generation are only estimates. According to statistics [11] the actual gross electricity generation in 2004 (3 179 TWh) was in fact slightly higher than the prediction for 2005 (3 177 TWh).

4.7.3 Calculation of fuel consumption and CO_2 emissions

Fossil fuel consumption is calculated by multiplying the total amount of electricity generated per technology in each five-year period by an efficiency factor that corresponds to the power plant fleet of the respective technology for that period of time. The efficiency factor is calculated as a weighted average based on the composition of the power plant fleet in terms of age for each technology. The average efficiencies assumed for the existing power plant fleet are 35% for coal plants, 53% for natural gas combined cycle plants and 34% for open cycle gas turbines. These figures are used to estimate the fuel consumption and CO_2 emissions of the existing capacity, which will still be in operation throughout the time span of the analysis. For new capacity, figures from Table 4.2 are used.

The corresponding CO_2 emissions are calculated by taking into account the average lower heating value and the average carbon content of the fuel consumed, as shown in Table 4.3.

The grouping of power plant types according to the criteria laid down in the following chapter, and the application of the above mentioned approach for calculating CO_2 emissions from the current capacity mix, as reported by EUROSTAT for the year 2004 [11], yields a value for the CO_2 emissions of the sector equal to 1 340 Mt. In 2004, the actual emissions of the electricity sector were 3% lower than the 1990 levels, i.e. 1 355 Mt. This result confirms that the methodology and power plant grouping adopted in the study do not cause significant deviations in terms of CO_2 emission calculations, and hence provides a valid starting point for the assessment of future trends.

4.7.4 Average production cost of fossil-fuelled electricity

The technology mix for each five-year interval, as calculated by applying the methodology described in paragraphs 4.6 and 4.7.2, includes newly built and existing power plants. The cost curves for the new plants are calculated using the figures from Table 4.2. However, in order to estimate an average cost of electricity, the operating costs of all power plants of the same type need to be taken into account. This is done as follows:

- cost curves are re-calculated per technology using a weighted average for each cost component based on the age distribution of the fleet;
- for existing capacity (in operation before 2005), the costs of the year 2005 are assumed, along with the efficiencies stated in Section 4.7.3;
- coal plants older than 25 years do not carry capital investment costs, as the economic lifetime of all plants is set to 25 years;
- the discount rate is 10%.

The total cost is derived by multiplying the costs with the operating hours calculated for each technology. The average production cost of electricity is calculated by dividing the total cost by the total amount of electricity generated.

	Carbon content (%w)	LHV (kJ/kg)
Natural gas	72.25	46 500
Coal	66.50	25 150

Table 4.3: Fuel properties assumed for the purposes of the study

5 Snapshot of the Fossil Fuel Power Generation Capacity in the European Union

This Chapter initially presents an overview of the power generation sector, based on the latest EUROSTAT data and subsequently maps the existing fossil-fuel-fired electricity generation fleet, providing information concerning its age according to technology and fuel type. Based on this information, the remaining life of the currently operating fossil fuel power plants is then estimated. This information is used in the following Chapters for the calculation of the requirements for new capacity.

5.1 Overview of the power generation sector

According to the latest available information from EUROSTAT [11] at the time of writing (which refer to the year 2004), the total installed electrical capacity in EU25 was 706.4 GW. Public systems accounted for the vast majority of the capacity (93%) while the capacity of autonomous producers was 51.5 GW. Thermal power plants (fuelled mostly by fossil fuels as well as by relatively small quantities of biomass, biogas, waste and derived gases) accounted for 58% of the total installed capacity (408 GW), followed by hydro and other renewables, mostly wind and geothermal, (23% of total installed capacity), and nuclear power plants (19% of total capacity). The total gross electricity generation from these plants was 3 179.1 TWh. Most of the electricity was generated by thermal plants (56%), followed by nuclear plants (31%), and hydro and other renewables (13%), see Figure 5.1. Based on these data the capacity factor of the total electricity generation sector was estimated at 51%, while the average capacity factors of the thermal, nuclear and hydro/renewable plants were calculated to be 50%, 85% and 28% respectively.

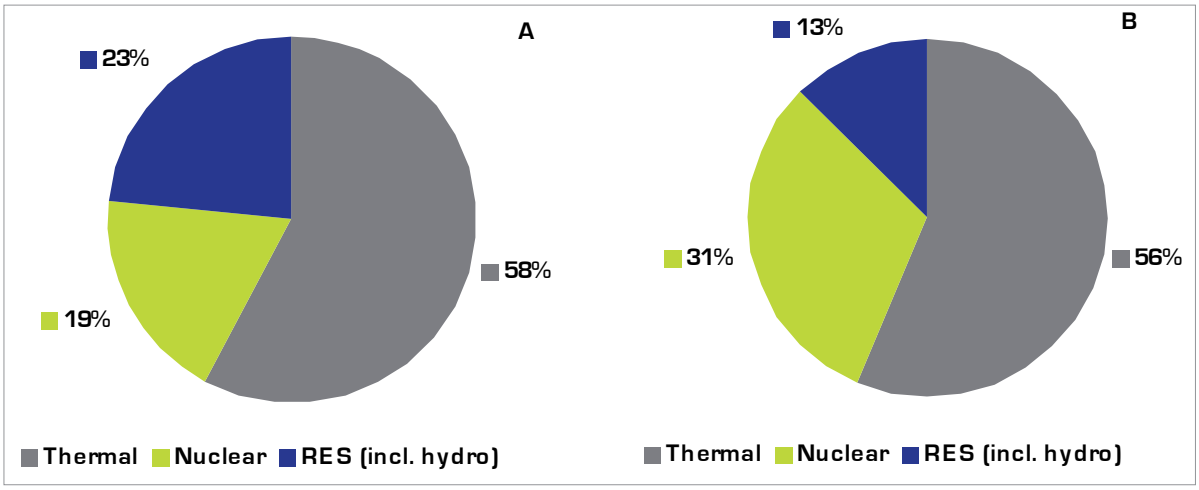

Figure 5.1: (A) Installed electrical capacity, and, (B) total power generation, by type of plant for the EU-25 in 2004 (11)

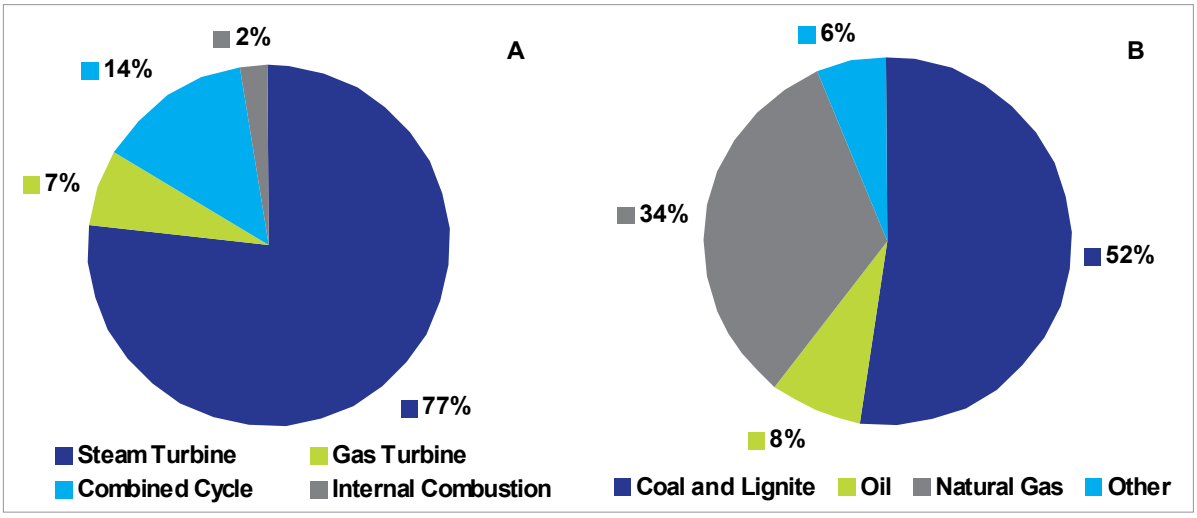

Figure 5.2: (A) Installed thermal power plant capacity by technology; (B) Thermal power generation by fuel (11).

These figures highlight the pivotal role of thermal power plants in the European electricity generation system. These plants are mostly of the steam type and rely on solid fossil fuels, i.e., hard coal and lignite and to a lesser extent peat. The latest available data from EUROSTAT on thermal power plant types, which refer to the year 2001, show the following breakdown by plant type: 77% steam plants (295 GW); 14% combined cycle plants (53 GW); 7% gas turbines (27 GW); and 2% internal combustion reciprocating engines (9 GW), see Figure 5.2. Concerning the type of fuel used, in 2004, 52% of the electricity generated by thermal plants was based on solid fossil fuels; 34% on natural gas; 8% on oil products; and the remaining 6% on other fuels such as derived gases, biomass and industrial waste, see Figure 5.2.

5.2 Map of the power generation infrastructure in 2005

A dataset for the base year 2005 that has been compiled in this study, based on the EPIC [25] and PowerVision [26] databases, includes 7 484 units in 4 634 fossil fuel power plants identified as 'operational' in the source databases, with a total capacity of 395.9 GW. This value is 2.9% lower than that reported by EUROSTAT for 2004 [11]. However, the EUROSTAT figure includes the capacity of autonomous producers. Hence, there is a very good agreement between the existing capacity estimates in this report and the values reported by EUROSTAT.

The identified power plants are classified according to fuel and technology as follows.

Classification according to fuel:

- coal plants, including plants that use hard coal, lignite or peat;
- oil plants, encompassing those that use petroleum derived fuels;
- gas plants, including plants fired by natural gas, derived gas or mine gas.

Bi-fuel plants have been assigned to the dominant fuel type used.

Classification according to technology:

- combined cycle plants, including gas-fired combined cycle plants, as well as few coal- and oil-fired integrated gasification combined cycle plants (IGCC) when explicitly marked as such in the source databases;
- steam plants, including the vast majority of the coal- and oil-fired plants, as well as the gas-fired boiler-based units (approximately a quarter of the gas-fired capacity);
- gas turbines, encompassing all single cycle turbines fuelled by gas, as well as those few gas turbines fuelled by oil products when explicitly marked as such in the source databases;
- internal combustion reciprocating engines that are fuelled by oil or gas.

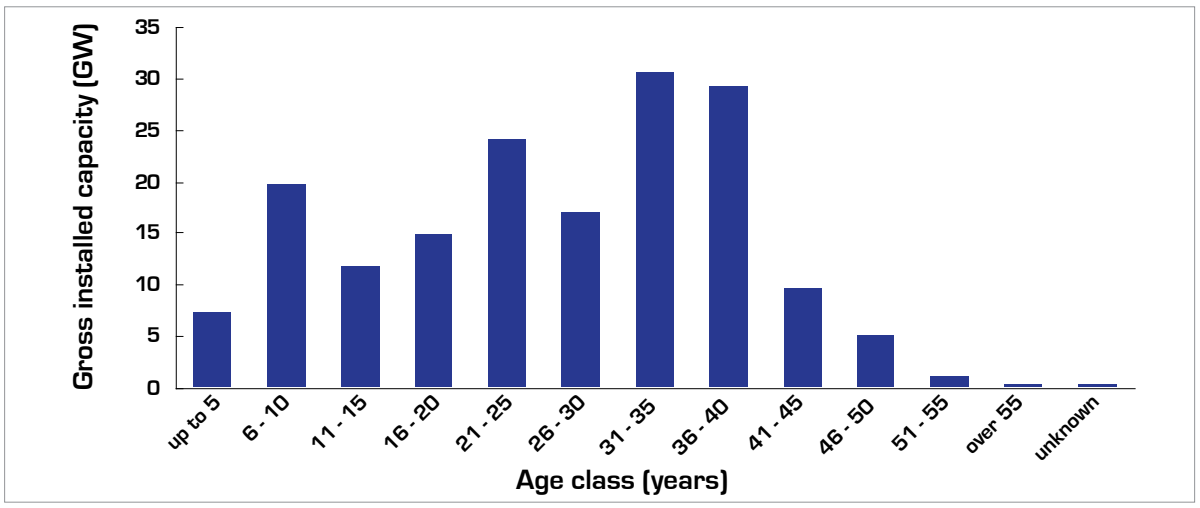

Figure 5.3: Age distribution of coal plants

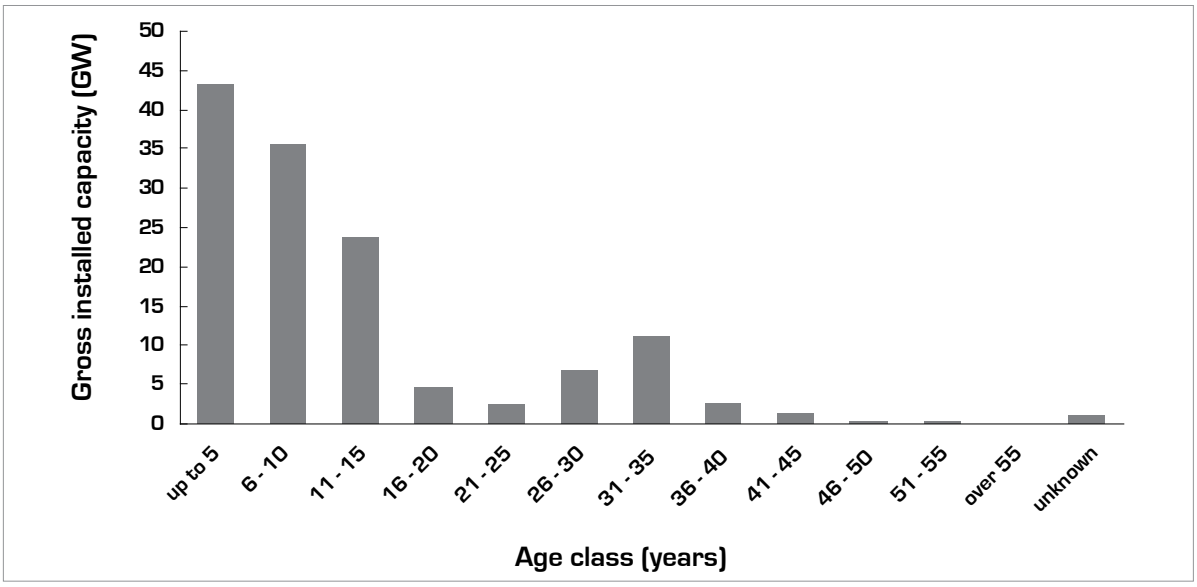

Figure 5.4: Age distribution of gas-fired plants

For a small number of plants, the conversion technology was not mentioned in the source databases; these plants have been categorised as 'Unknown'.

The age distribution of the power plants is shown in Figure 5.3 to Figure 5.7. The average age and the fraction of the operating installed capacity that is older than 25 and 40 years are shown in Table 5.1.

These results highlight the advanced age of the current power plant fleet. Among the various types of fuel, coal-fired plants are the oldest. 54% of coal capacity (approx. 93.3 GW) is already over 25 years old and almost 10% (16 GW) is over 40 years old. The situation is similar for oil-fired plants, although their capacity is much lower than that of coal: 52 GW of oil capacity are over 25, and 4.2 GW are over 40 years old. The picture is quite different for gas-fired plants. Just 17% of the installed capacity, 22.2 GW, is over 25 years old, mostly of the steam type. Most natural gas-fired electricity generation capacity is relatively young, including the highly efficient combined cycle plants built during the last decade.

Figure 5.5: Age distribution of oil-fired plants

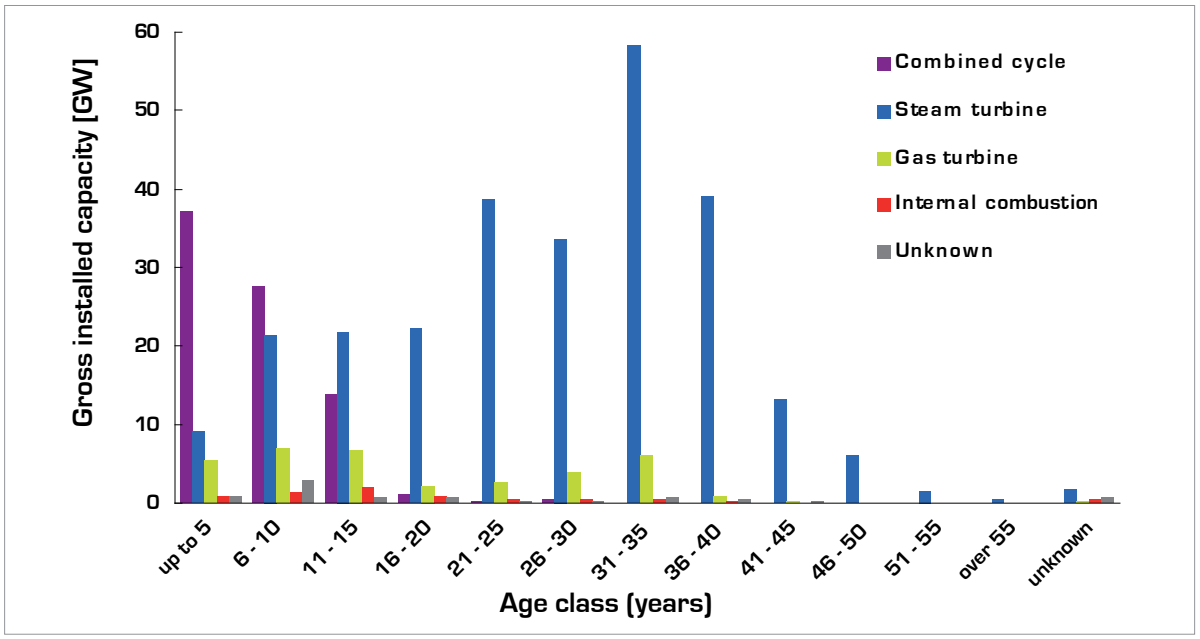

Figure 5.6: Age distribution of power plants by type of technology

	Average age	Fraction of capacity older than 25 years	Fraction of capacity older than 40 years
Coal	26	54%	9%
Gas	12	17%	1%
Oil	26	55%	5%
All fuel	21	42%	6%

Table 5.1: Age characteristics of the currently operating (2005) fossil fuel power plant fleet

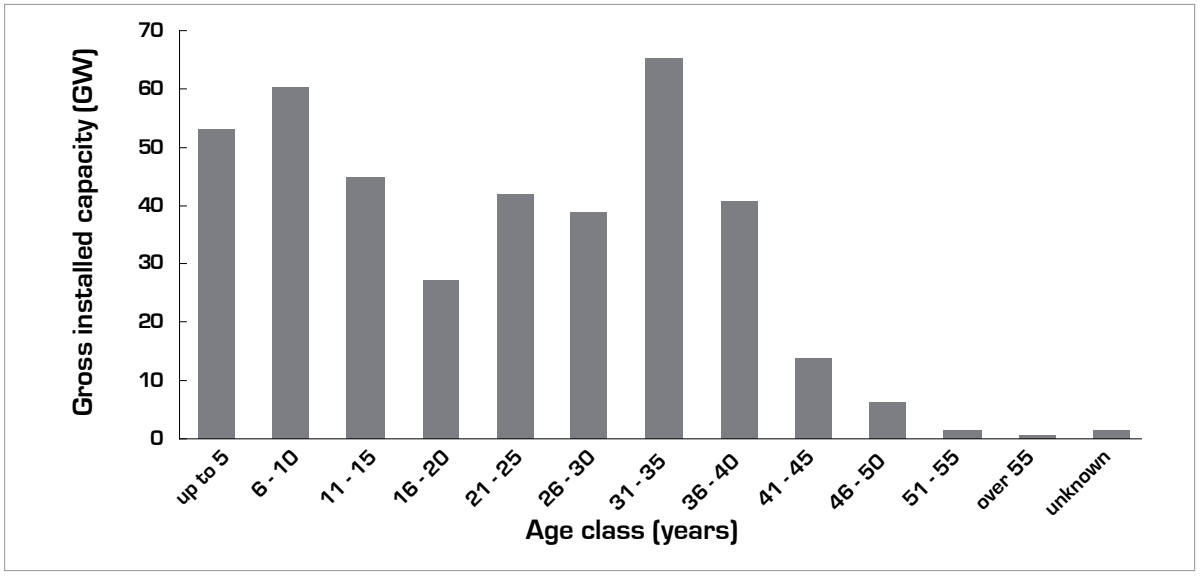

Figure 5.7: Age distribution of the fossil fuel power plant park

5.3 Remaining lifespan of the currently operating fossil fuel power generation capacity

Assuming that a steam plant is retired after 40 years of operation and all other types of plant are retired at the age of 25 years, 334 GW of existing plants will be retired by 2030, bringing the currently installed capacity down to 63 GW. The remaining capacity will mainly comprise steam plants (84%), and will be fuelled mostly by coal (60%), followed by oil products (21%) and natural gas (19%). The evolution of the remaining capacity of the current power plant fleet by technology type and by fuel is shown in Figure 5.8 and Figure 5.9 respectively.

These results are further regrouped – based on techno-economic criteria – into categories corresponding to the technology options that are used in the application of the screening curve method that follows. These are:

1. supercritical pulverised coal (PC);
2. combined cycle natural gas (NGCC); and
3. an open cycle natural gas turbine (GT) as described in Section 4.4.

More specific details are set out below.

- Gas turbines and internal combustion reciprocating engines have been merged into the 'GT' category and are assumed to operate on natural gas. Approximately 50% of this category is actually oil fired.

	2005	2010	2015	2020	2025	2030
PC	268	205	147	113	75	52
NGCC	80	80	79	65	37	2
GT	50	33	30	23	15	9
Total	397	318	256	201	127	63

Table 5.2: Grouping of remaining capacity (in GW) according to the technology options considered in the study.

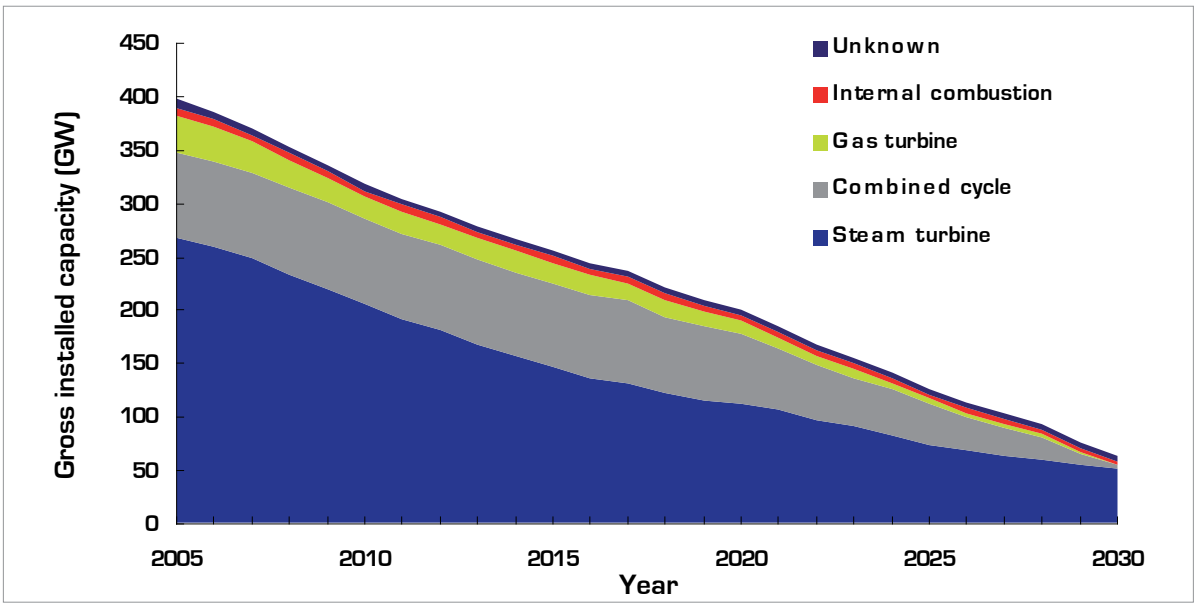

Figure 5.8: Estimated capacity of currently operating plants that will be in operation in the period from 2005 to 2030, according to the life expectancy assumptions of this study, sorted by technology type.

- Natural gas combined cycle plants make up the 'NGCC' category.

- All coal and lignite plants, as well as natural gas and heavy fuel oil plants using boiler/steam turbine technology are grouped in the 'PC' category. In real terms, 65% of this group is indeed coal or lignite fired, around 12% runs on natural gas and the remaining capacity runs on heavy fuel oil. Lignite accounts for a little over a third of the coal-fired capacity.

Table 5.2 summarises the remaining capacity of the already existing fleet in each five-year period.

This latter grouping is intended to assist with the implementation of the screening curve method. Even though not explicitly stated, it is recognised that part of the new capacity may be lignite or oil fired, according to the availability of fuel in different regions.

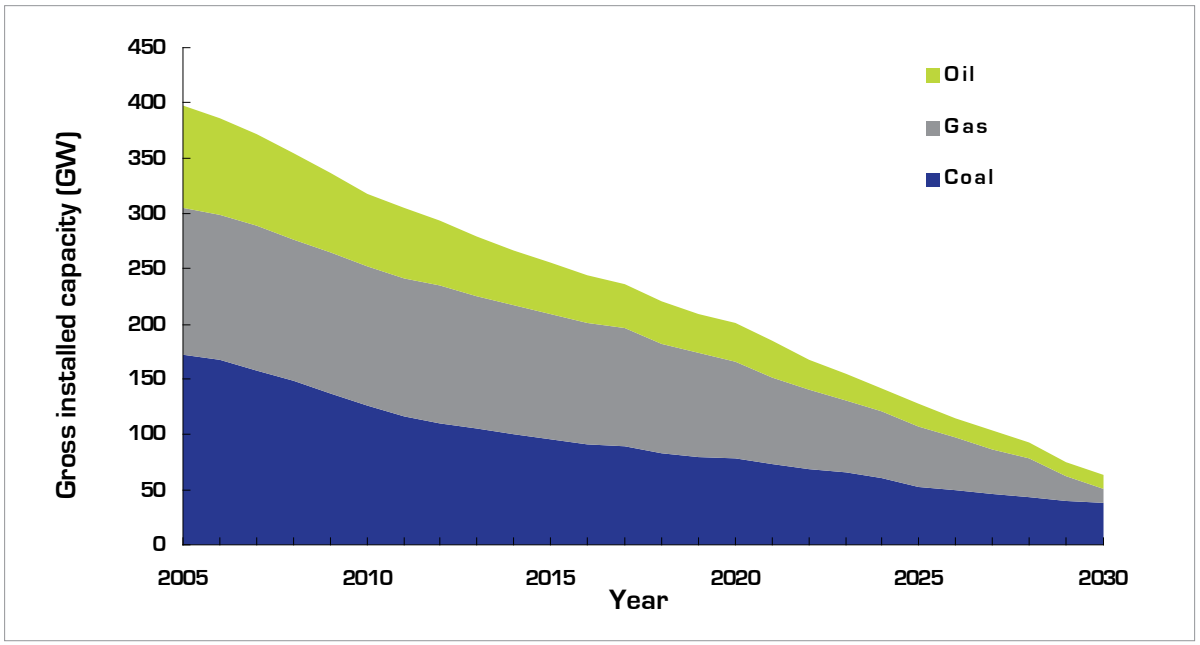

Figure 5.9: Estimated capacity of currently operating plants that will be in operation in the period from 2005 to 2030, according to the life expectancy assumptions of this study, sorted by fuel type.

6 The BAU Case: Fossil Fuel Power Plant Park Composition and Impacts

This chapter examines the evolution of the fossil fuel electricity generation capacity in the *BAU case*. Initially, the need for new capacity is identified, and the technology mix for each scenario is described. Subsequently, the capital requirements for the build-up of the new capacity are calculated, followed by results for fuel consumption and diversification, CO_2 emissions and an average electricity production cost for the fossil-fuelled power generation fleet.

6.1 New capacity required

In the *BAU case* the fossil fuel power plant capacity that needs to be operational in 2030 to meet the forecasted demand for electricity is calculated to be 700 GW (this takes into account peak load projections up to 2030 and a 20% reserve margin). Hence, 300 GW of additional capacity is needed, compared to the 2005 level, to meet the increasing electricity demand in view of the modest penetration of non-fossil fuel power generation technologies that has been assumed in the BAU case.

Moreover, as was shown in the previous chapter, the currently operating capacity of 400 GW is reduced to 60 GW in 2030 as existing power plants are gradually retired[18]; widening the gap between the required capacity and the operational capacity of power plants built before 2005 (see Figure 6.1).

Overall, the new fossil fuel power plant capacity that needs to be constructed by 2030 is estimated at 635 GW (Figure 6.2), which is one-and-a-half times the size of the currently installed fossil fuel power plant capacity. This capacity is built gradually over the next 25 years, albeit at different rates. The most intensive time for building new capacity is the period from 2005 to 2010, where approximately 200 GW are built within five years, mostly to replace the older power plants that were in operation until 2005 and have exceeded their assumed technical lifetime. The intense activity indicated for the period from 2000 to 2005 does not necessarily reflect reality but it is rather a result of the forcible retirement of aged capacity within this period as assumed by the model. In practice, it is more likely that the lifetime of these plants will be extended and their replacements will be constructed over a longer time period.

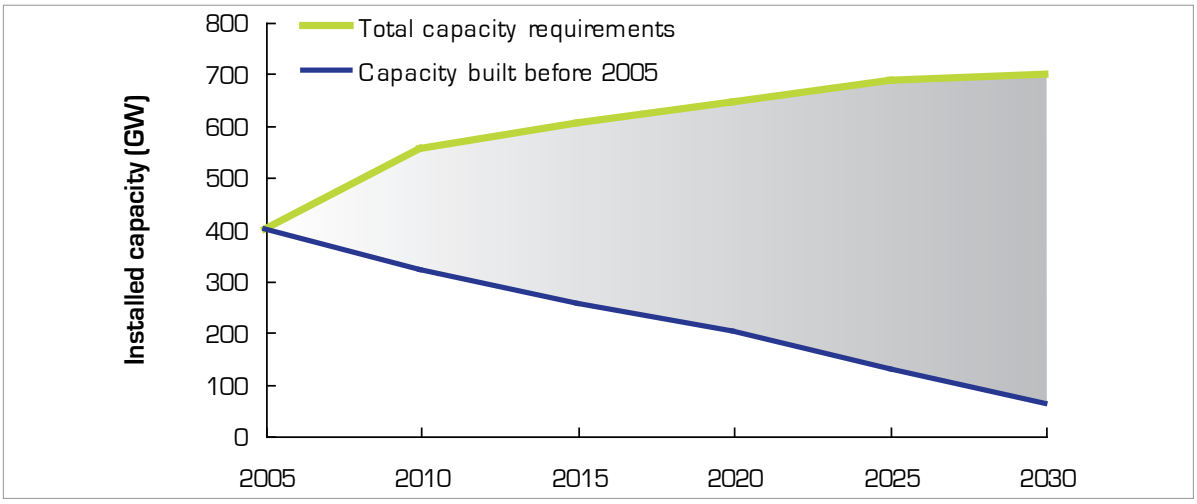

Figure 6.1: Evolution of the operating capacity of power plants built before 2005 and the total capacity requirements in the BAU case. The height of the highlighted area represents the new capacity needed.

18 Readers should bear in mind that a key assumption of this study is that power plants are retired as soon as they reach a fixed age, 25 or 40 years depending on the technology, and are not retrofitted to have their operational lifetime extended.

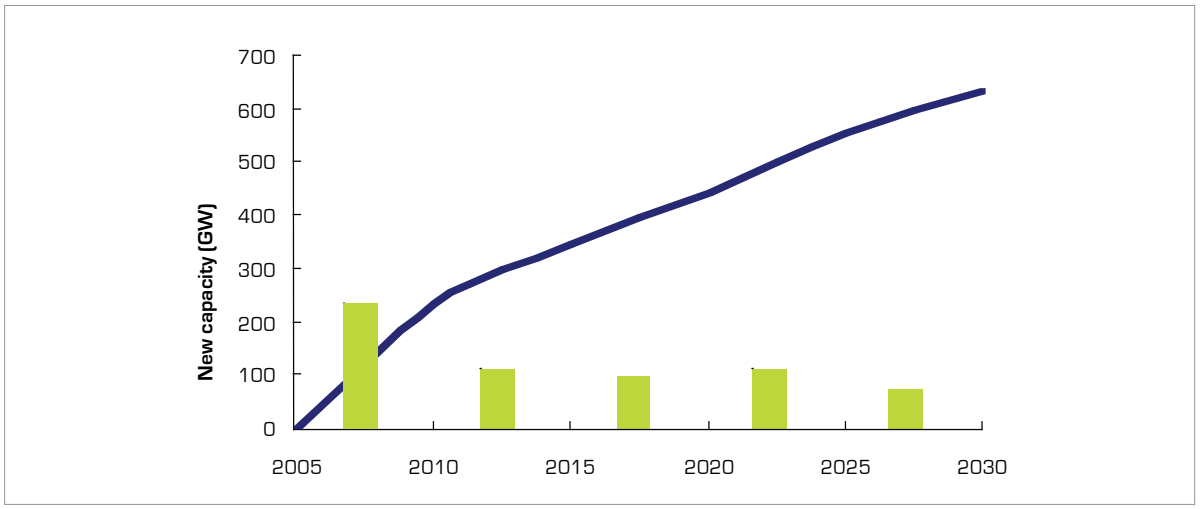

Figure 6.2: Requirements for new fossil fuel power plant capacity to 2030. The continuous line shows the cumulative new capacity, while bars indicate the capacity that needs to be built up during each five-year period.

6.1.1 Technology mix without the commercialisation and deployment of CCS

The portfolio of technologies that will meet the need for new capacity depends strongly on the fuel and carbon prices in each scenario. Figure 6.3 shows the contribution of different power plant technologies to the new capacity when CCS technologies are not considered (*no CCS case*). The common element in all six *BAU - no CCS* scenarios studied is the role of open cycle gas turbines. The share of this technology in the new capacity varies between 19% and 25% (120–160 GW), and is mostly built during the first five-year period to replace old infrastructure. It is used mainly to meet the peak load (operating for less than 20% of the year). In contrast, the penetration of NGCC plants and pulverised coal plants which operate in base load or load following mode varies significantly between scenarios.

When *CO_2 prices are high*, NGCC plants dominate the new capacity (graphs in the right-hand column of Figure 6.3). The share of this technology in new capacity varies between 75% and 80% (480-510 GW), depending on the fossil fuel prices. Coal plants only contribute towards a small share of new capacity in the case of *medium fuel prices*, with all new PC plants built in the first period (2005-10).The high levels of CO_2 emissions emitted by coal plants, the cost of which is carried over to the production cost of electricity, make this technology uncompetitive when compared to the less carbon-intensive NGCC. It is apparent that fuel prices are less important than the CO_2 price in influencing the development of the technology mix in this case.

When the *CO_2 price is low* the situation changes significantly (see graphs in the left-hand column of Figure 6.3). The penetration of PC technologies varies widely. At *low fuel prices* it accounts for just 11% of new capacity. However, under *the medium and high fuel price scenarios*, it dominates the new capacity, with a share of 54% to 62% (350-400 GW) respectively. Clearly, high natural gas prices make NGCC technology less competitive compared to coal technologies, even when coal prices reach their assumed maximum. Thus, in the *medium and high fuel price scenarios*, the competitiveness of NGCC technology diminishes after 2010 due to the unfavourably high natural gas prices and the high natural gas-to-coal price ratio.

In essence, *high carbon prices*, in the absence of carbon capture technologies, are detrimental for the penetration of coal power plant technologies, irrespective of the fuel price. Low fuel prices also favour NGCC technology, independent of the CO_2 price. On the other hand, *low CO_2 prices* favour the further penetration of PC technology at the expense of NGCC when *fuel prices are medium or high*.

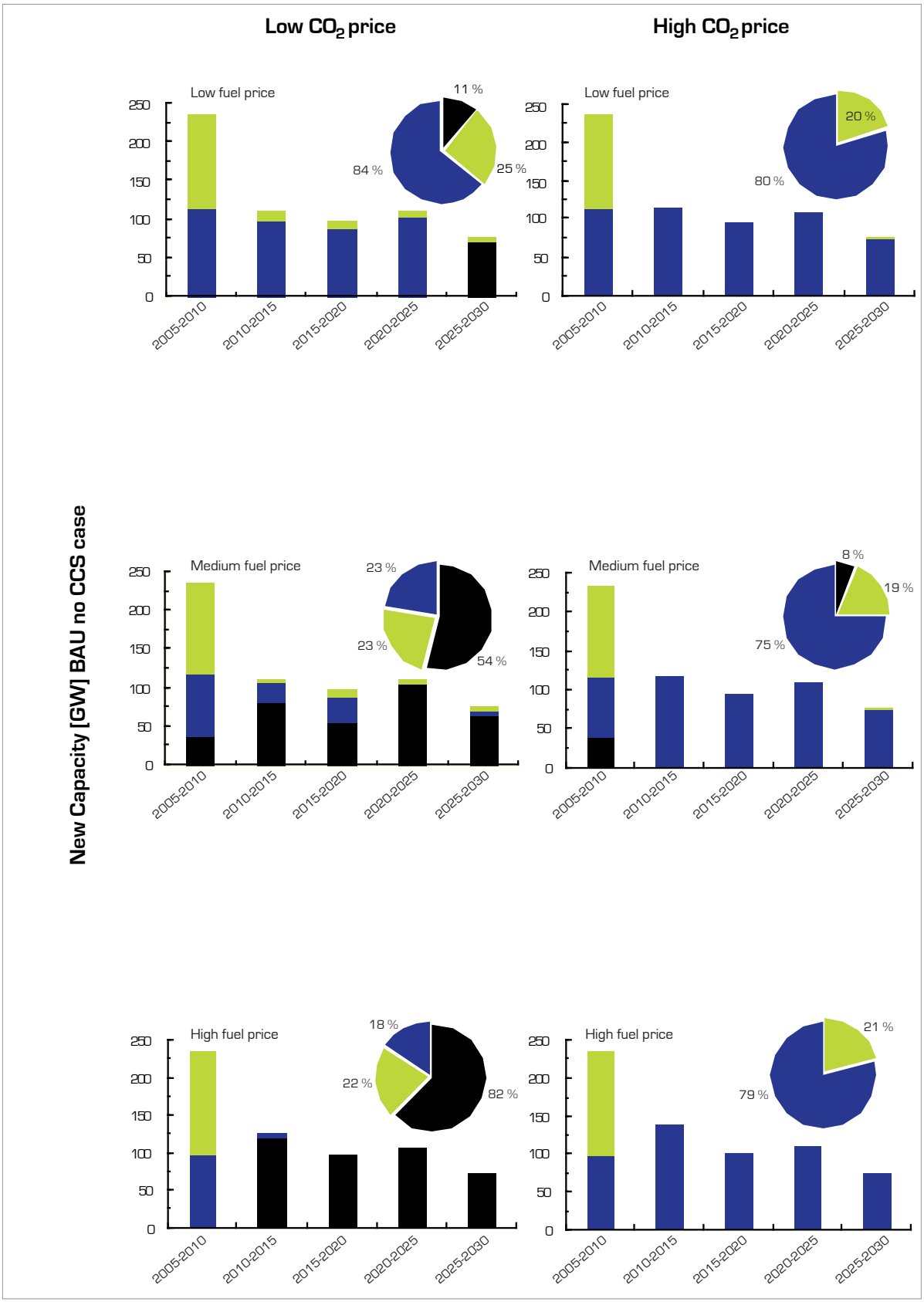

Figure 6.3: New capacity requirements by technology in the BAU case without CCS for different fuel and carbon price combinations. The bar charts show the capacity required in each period by technology type, while the pie chart displays the share of each technology in the capacity built throughout the 2005 to 2030 time period.

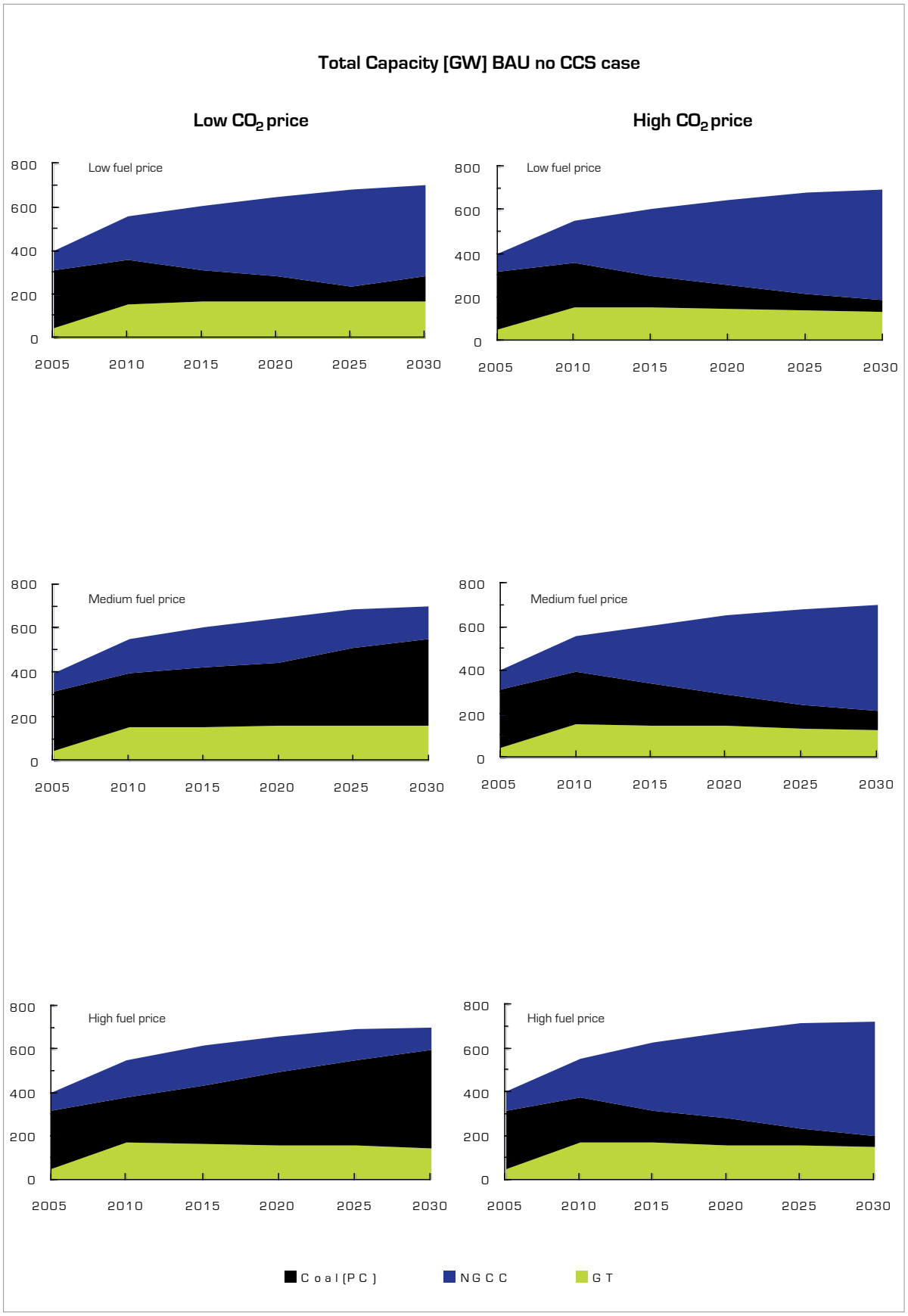

Figure 6.4: Total installed capacity by technology in the BAU no CCS case for different fuel and carbon price combinations.

The evolution of the total installed capacity (i.e. new and existing) in the *BAU no CCS* case is shown in Figure 6.4. In all scenarios, open cycle gas turbines have a share of approximately 20% in 2030, the remaining capacity being split between NGCC and PC technologies. For *low CO_2 prices and medium to high fuel prices*, the share of coal technologies in 2030 ranges between 57% and 64% (410-460 GW). However, in all other cases PC only accounts for 7% to 17% (50-120 GW) of the total capacity in 2030. To put these figures in perspective, the coal-fired installed capacity in 2005 was 44% of the total, accounting for approximately 52% of power generation. Therefore, the role of coal technologies in the European electricity generation system, in the absence of carbon capture and storage, is likely to decrease in importance in the coming years.

Unless a combination of favourable conditions is present in the fuel and carbon markets (*low CO_2* combined with *high/medium fuel prices*), coal technologies cannot maintain their position as the technology of choice for power generation. In the case of *high CO_2 prices,* no coal power plants are built beyond 2010.

6.1.2 Technology mix with the deployment of CCS

The consideration of power plants that are capable of capturing and storing CO_2 (*BAU CCS case*), along with conventional power plant technologies, does not affect the technology mix when *CO_2 prices are low.* In other words, the type and capacity of power plants built during each period in the *BAU CCS* case is identical to that in the *BAU no CCS* case (as shown in the graphs in the left-hand column in Figure 6.5 and Figure 6.3). When *CO_2 prices are low,* the financial incentive of avoiding paying for the CO_2 emissions via capture is not sufficient to make plants with CO_2 capture more competitive than conventional plants.

On the other hand, when *CO_2 prices are high,* the economic penalty of CO_2 emissions is enough to drive the deployment of CCS plants (graphs on the right-hand side of Figure 6.5). As soon as CCS plants are commercialised they become the only plant type that is built to fill the capacity gap, and the share of NGCC in the new capacity is limited to between 31% and 36% (compared to a 75% to 80% share in the *BAU no CCS* case), depending on the fuel price, with all NGCC capacity built before 2015.

While fuel prices do not affect the total contribution of CCS plants to the new capacity (around 44% in all cases), they do influence the type of capture plant chosen. Under *low fuel prices,* NGCC with CCS is the most competitive technology during the period from 2015 to 2025, before finally giving way to IGCC-CCS by 2030. NGCC with CCS takes up 32% (200 GW) of the new capacity, while IGCC-CCS contributes the remaining 12% (80 GW) of the capture plant capacity.

For *medium or high fuel prices,* IGCC plants with CCS are the most competitive technology among all those considered. In this case, IGCC-CCS plants reach a share of 44% (280 GW) of all new fossil fuel capacity in 2030, irrespective of the price situation in the fossil fuel international market. PC-CCS, although considered in the analysis as a mature and available technology along with IGCC-CCS and NGCC-CCS, proves to be non competitive under the assumptions of the study. Hence, PC-CCS plants are not deployed in any of the scenarios considered.

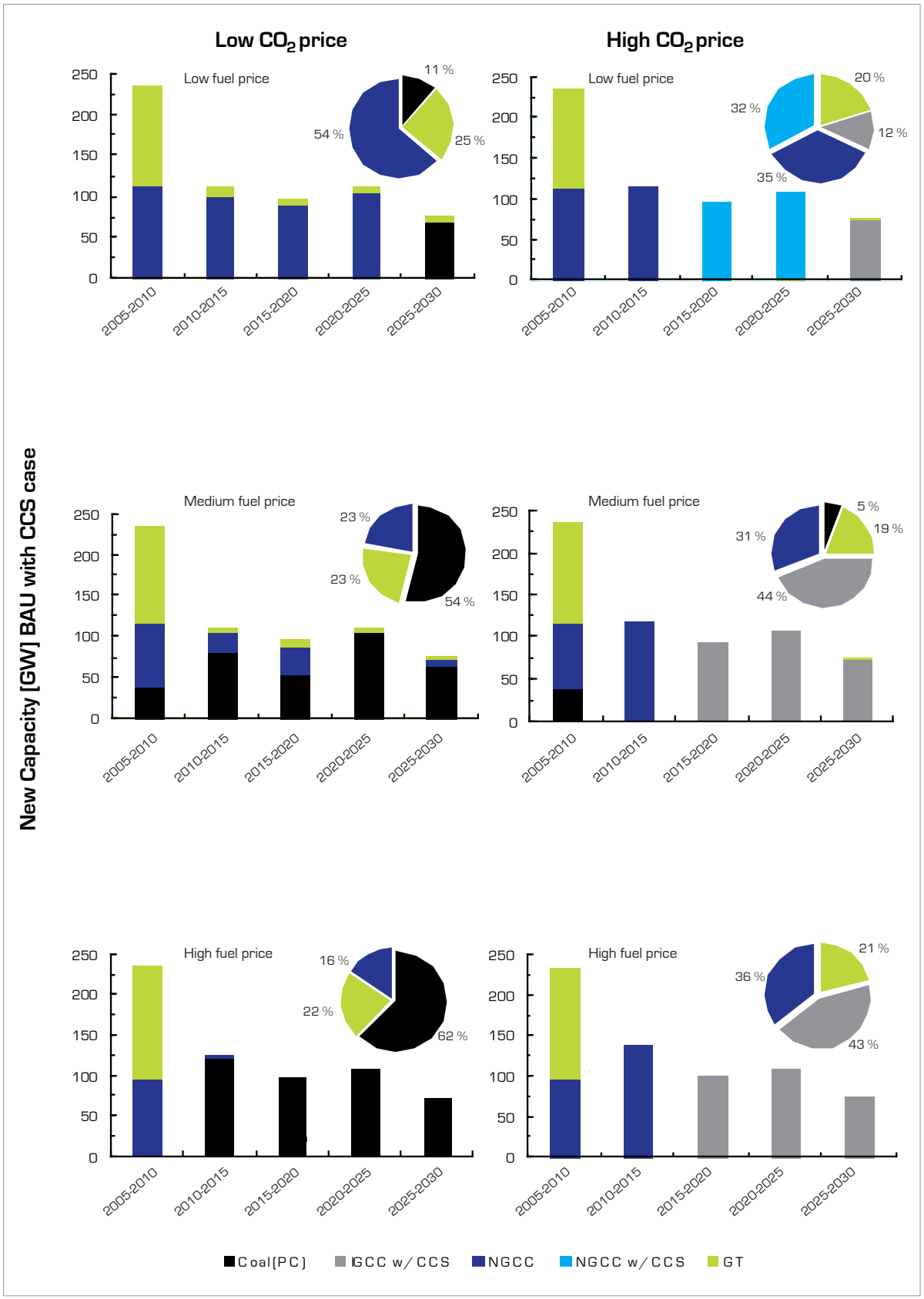

Figure 6.5: New capacity requirements by technology in the BAU CCS case for different fuel and carbon price combinations. The bar charts show the capacity required during each period by technology type, while the pie chart displays the share of each technology in the capacity built throughout the period from 2005 to 2030.

Ultimately, the contribution of CCS plants in the total installed capacity reaches a share of 40% in 2030 (Figure 6.6).

The threshold CO_2 price for the introduction of CCS plants in the electricity generation system depends on the fossil fuel prices. This threshold is calculated at EUR 34/t CO_2 for the *high fuel price* case, EUR 55/t CO_2 for *low fuel prices* and EUR 52/t CO_2 for the *medium fuel price* case, if the technology is to be deployed in the period from 2015 to 2020 (to allow these plants to become operational in

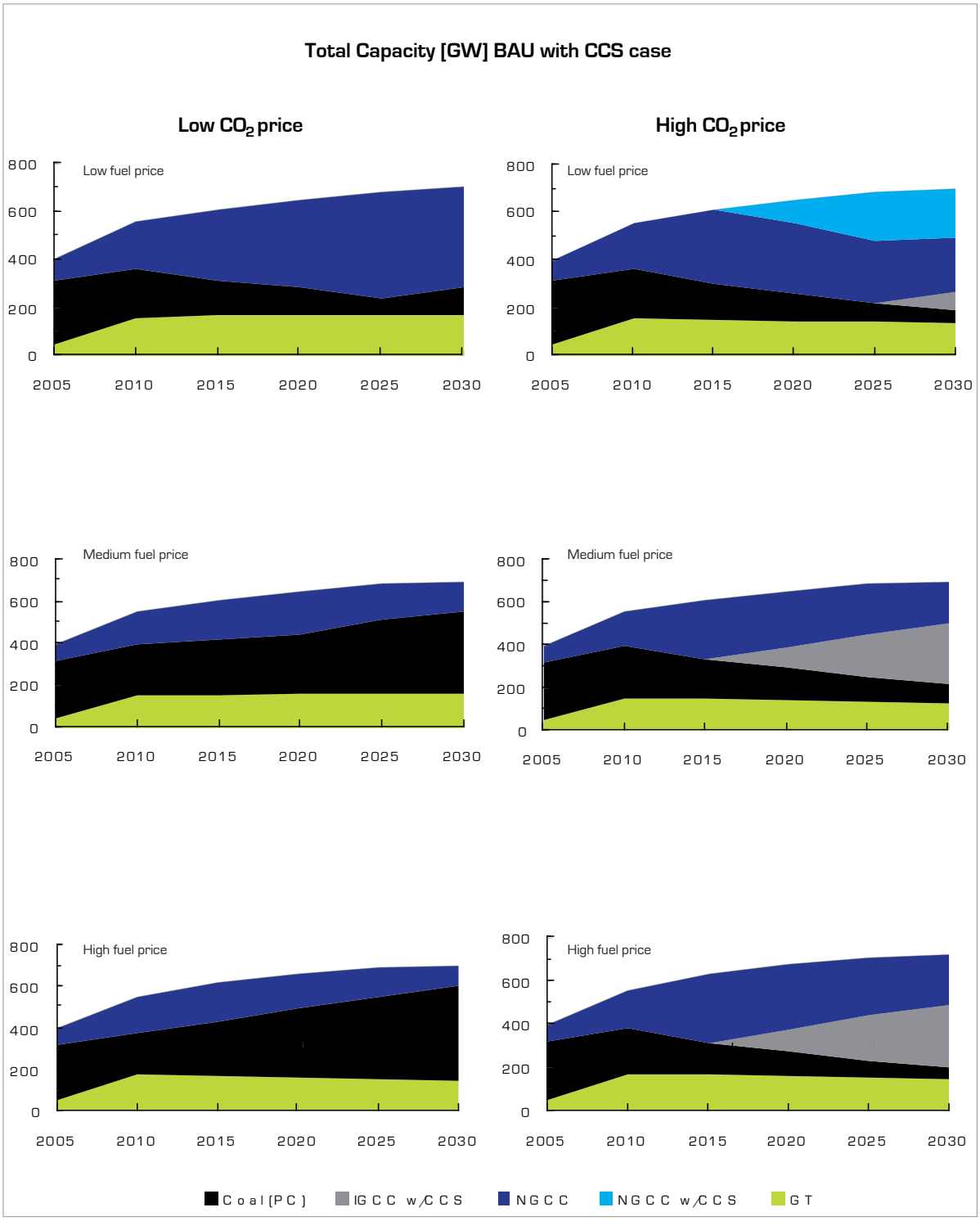

Figure 6.6: Total installed capacity by technology in the BAU CCS case for different fuel and carbon price combinations.

CCS introduction year Fuel price scenario	2020	2025	2030
High fuel prices	34	30	26
Medium fuel prices	52	30	25
Low fuel prices	55	46	30

Table 6.1: Threshold CO2 prices (EUR/t) necessary for the deployment of CCS technology, assuming different timings for the introduction of the technology to the power plant fleet.

2020). The minimum carbon price necessary for the introduction of CCS in the power generation mix becomes lower as the introduction of the technology in the technology mix is delayed (see Table 6.1). However, if the introduction of CCS technology is delayed, then the contribution of CCS plants in the new capacity mix by 2030 will be lower.

6.1.2 Sensitivity of the capacity mix to fuel prices

As previously discussed, fossil fuel prices are externally imposed onto the analysis, rather than being considered as a parameter influenced by changes in the system modelled. In the context of this study, three specific scenarios for the evolution of fuel prices have been taken into account, each with different absolute prices and ratios for the relationship between natural gas and coal prices as described in Section 4.5.1. In this section a sensitivity analysis is presented that examines the influence of absolute coal and gas price levels as well as price ratios to the technology mix of the new capacity.

In this sensitivity analysis, coal prices, starting from EUR 1.50/GJ, are increased linearly over the period from 2005 to 2030 at different annual rates that range from 1% to 6%, to reach maximum prices ranging between EUR 1.75/GJ and EUR 3.00/GJ respectively. At the same time, ratios between 2.0 and 4.0 are assumed for the natural gas-to-coal price ratios so that the maximum natural gas prices in 2030 range between EUR 3.50/GJ and EUR 12.00/GJ respectively. The technology mix of the new capacity was then calculated for all these fuel price combinations.

Figure 6.7 shows a qualitative representation of the influence of absolute fuel prices and fuel price ratios on the technology mix when CCS technology is not deployed, either because the technology is not competitive (low CO_2 prices), or because it is not available. For low price ratios (under 2.4), which also signify low absolute natural gas prices, the technology mix is dominated by natural gas technologies, whose share in the new capacity is

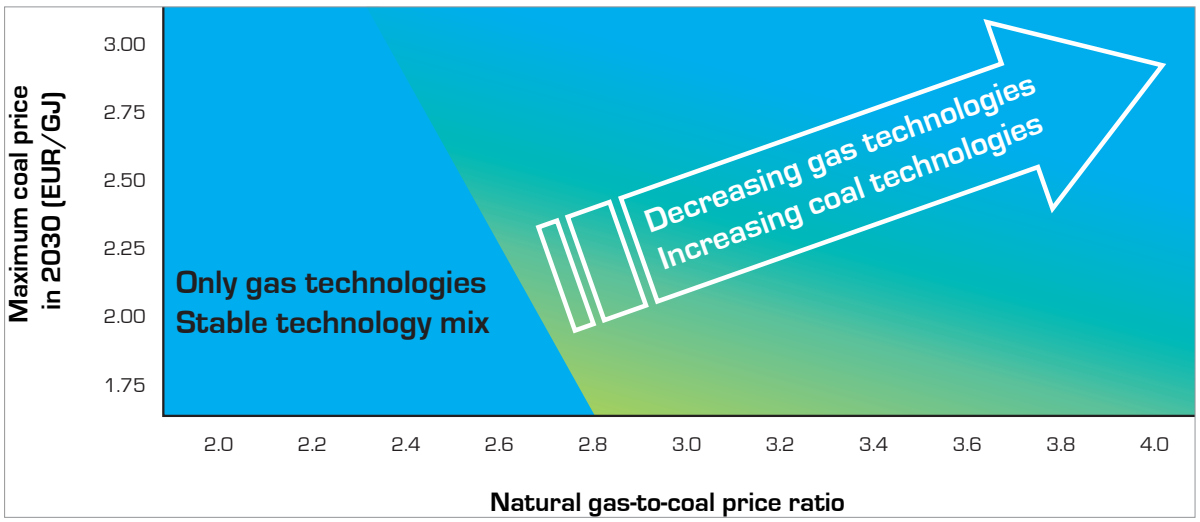

Figure 6.7: Influence of absolute fuel price and natural gas-to-coal price ratio on the technology mix of the new fossil-fuel-powered capacity in a situation where CCS technologies are not deployed. Moving from light blue to grey areas indicates the gradual shift from natural gas- to coal-fired technologies.

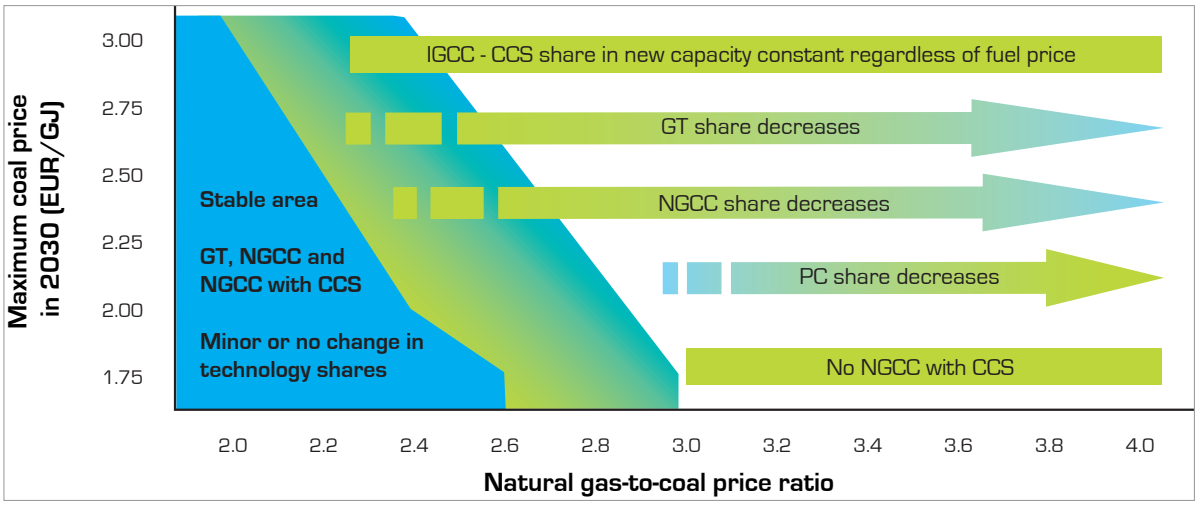

Figure 6.8: Influence of absolute fuel price and natural gas-to-coal price ratio on the technology mix of the new fossil-fuel-powered capacity in the case of CCS deployment.

constant. For fuel price ratios between 2.4 and 2.8, coal technologies may be introduced into the new capacity, depending on the absolute fuel prices. At price ratios higher than 2.8, as natural gas becomes more expensive compared to coal, natural gas technologies retreat and the share of coal plants in the mix increases, especially if absolute prices for both fuels are also high.

In the case of CCS deployment, the trend is the same with regards to conventional technologies that do not capture CO_2. In addition, NGCC-CCS plants have a constant share in the new capacity when fuel price ratios are low. With increasing price ratios, a transition zone is observed (hatched area in graph Figure 6.8) when CCS capacity moves from being only NGCC-based to comprising only IGCC plants. Beyond the transition zone, IGCC has a constant share in the new capacity while NGCC with CCS is absent. Conventional technologies behave as explained previously (Figure 6.7), although PC plants are only introduced to the capacity mix for price ratios 2.8 or higher.

6.2 Capital requirements

The capital requirements for the build-up of new capacity in each five-year interval depend on the incremental capacity needs and the technology mix identified as optimum for each scenario for the corresponding period of time. Figure 6.9 shows the overnight capital requirements in each period for all BAU scenarios, for different combinations of fossil fuel and CO_2 prices.

When *CCS is not available*, capital needs rise along with the share of PC in the new capacity. Thus *low CO_2 prices* in conjunction with *medium or high fuel prices*, which favour coal technologies, are associated with higher capital costs. On the other hand, *high CO_2 price* scenarios and *low fuel price* scenarios result in the build-up of NGCC plants that are less capital intensive than coal plants. As a consequence the capital needs beyond 2010 under the *high CO_2 price case* are about half of those generated under the *low CO_2 price case* for *medium or high fuel prices*.

For high CO_2 prices, the commercialisation of CCS is another factor that has a great impact on capital requirements. The construction of IGCC-CCS plants during the period from 2015 to 2020 and beyond results in the increase in capital requirements by approximately three times compared to the corresponding costs when CCS is not available for *medium and high fuel prices*. In the case of *low fuel prices*, the difference is not as prominent because the technology of choice is NGCC with CCS, which is not as expensive as the IGCC-CCS.

The cumulative overnight capital expenditure required for the build-up of the required capacity in all scenarios considered in the *BAU case* is summarised in Figure 6.10.

When *CCS is not available*, capital needs range between EUR 325 billion and EUR 550 billion. The lowest cost is associated with the *low fuel - high CO_2 price scenario*, where all new capacity is based on the use of gas turbine technology. The highest cost is associated with the *high fuel - low CO_2 price*

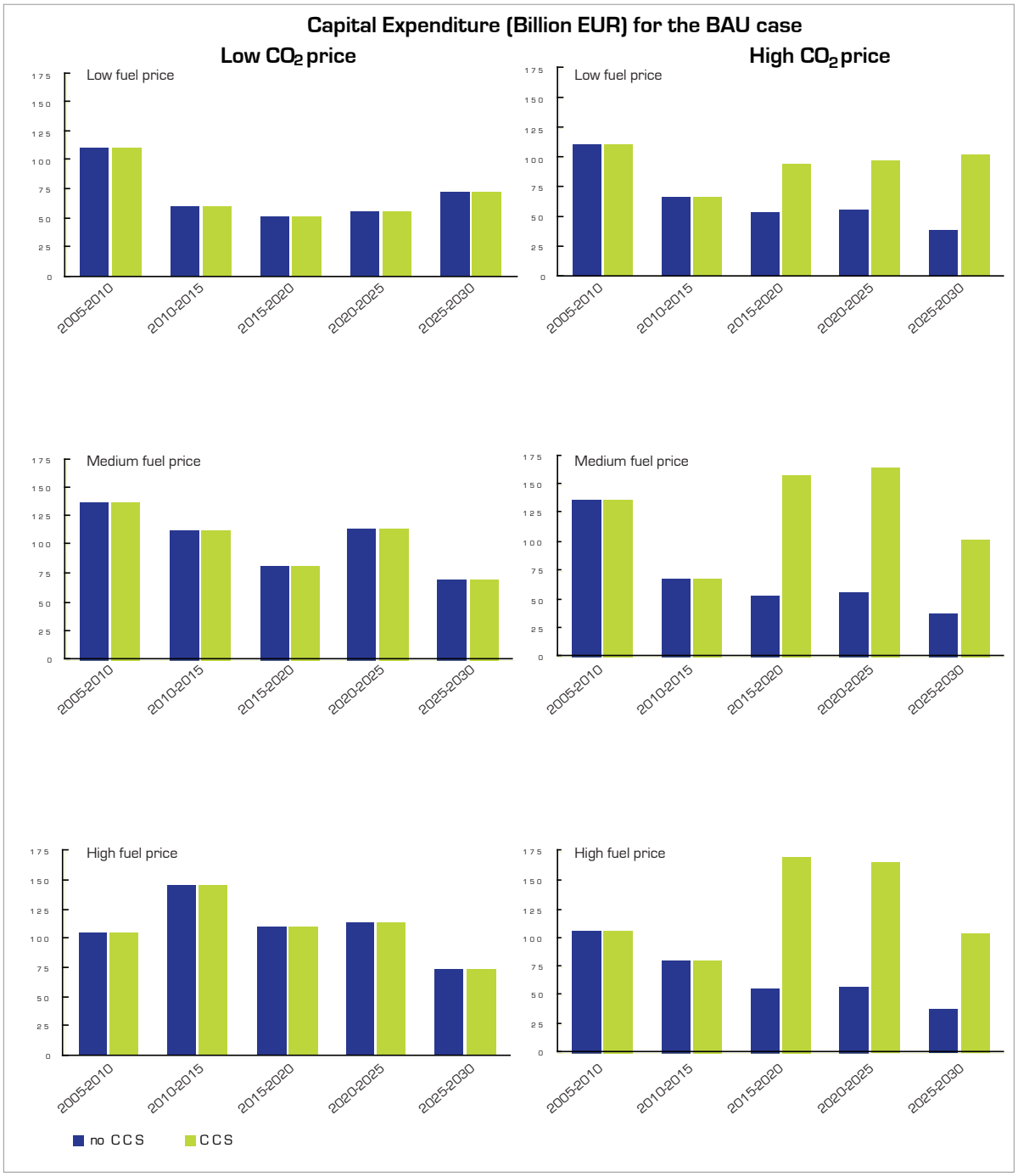

Figure 6.9: Capital requirements per five-year period for building the new fossil fuel capacity in the BAU case, with and without CCS, for different fuel and carbon price combinations.

scenario that favours coal technology and therefore a large share of PC plants in the new capacity.

The capital requirements when *CCS is available* vary between EUR 355 billion and EUR 630 billion. The lowest capital costs are associated with the scenario that considers both *low fuel* and *low CO_2 costs*, which results a technology mix with the lowest PC and the highest NGCC technology penetration and no CCS plants. On the other hand, the highest capital costs occur for *medium fuel and high CO_2 prices*, which result in the highest penetration of IGCC-CCS and coal plants at the same time. In the scenarios where CCS plants get a share of the new capacity, the cumulative capital expenditure is 80% to 85% higher than in the corresponding scenarios in the *no CCS case* when the technology used is IGCC, and 45% higher if most of the CCS is based on NGCC plants.

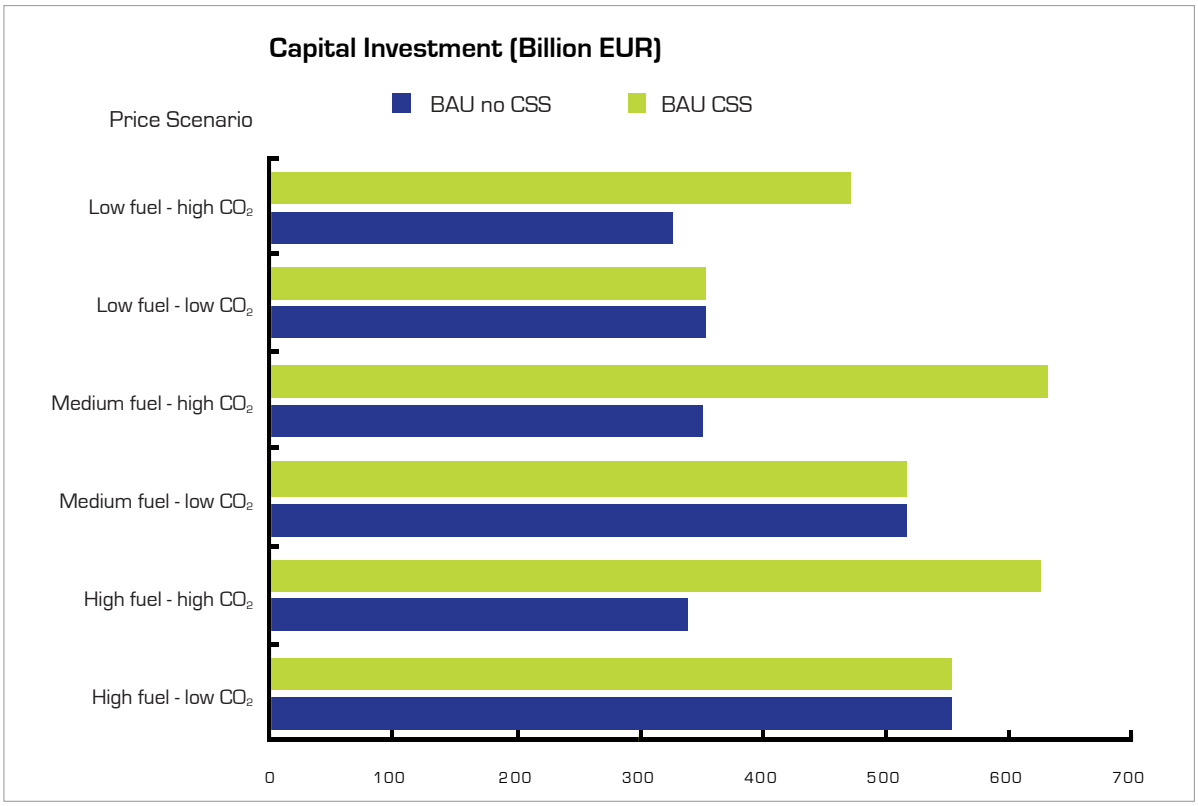

Figure 6.10: Comparison of cumulative overnight capital expenditure required for the expansion of the fossil fuel power plant generation sector to 2030 under the BAU case, for different fuel and carbon price combination scenarios.

6.3 Fuel consumption, diversification and cost

The technology mix has a paramount effect on fuel requirement, both in terms of absolute consumption and in the ratio of coal-to-natural gas used in the power generation sector. In 2004, the total fuel consumption for fossil fuel electricity generation was 15.4 EJ. Coal accounted for 61% of the total fuel consumption [11]. These are the latest available figures and are used as a starting point for the presentation of the results of this study.

6.3.1 Annual fuel consumption and coal share

Figure 6.11 shows the calculated trend of annual fossil fuel consumption for electricity generation, and the estimated share of coal in the fuel mix for the *BAU no CCS case*. There is an increase in fuel consumption for all scenarios, ranging between 9% and 56% of current consumption levels, by 2030. The fuel mix differs significantly between scenarios as it follows the trend of the capacity mix presented in Section 6.1.1.

Low CO_2 prices combined with *medium or high fuel prices* encourage the use of coal, the share of which rises to 85% to 95% of the annual fuel consumption by 2030. Conversely, *high CO_2 prices* aid the substitution of coal by natural gas in power plant infrastructure and consequently in the fuel mix, reducing the share of coal to 12% or less by 2030. In the case of *low CO_2* combined with *low fuel prices*, the use of coal rises again during the period from 2025 to 2030 but remains low (30% of the total) in 2030.

There is a correlation between an increased percentage of coal in the fuel mix and high fuel consumption. Scenarios with *low CO_2 prices*, which favour coal technology, show the largest increase in fuel consumption – up by 20% to 37%, reaching 21 EJ by 2030.This is due to the reduced efficiency of coal plants compared to NGCC plants. In contrast, scenarios with a high penetration of natural gas technology (i.e. *when CO_2 prices are high*), show a fuel consumption increase of the order of 9% to 12%, with annual fuel requirements around 17 EJ by 2030.

To put these figures in perspective, readers should bear in mind that electricity generation from fossil

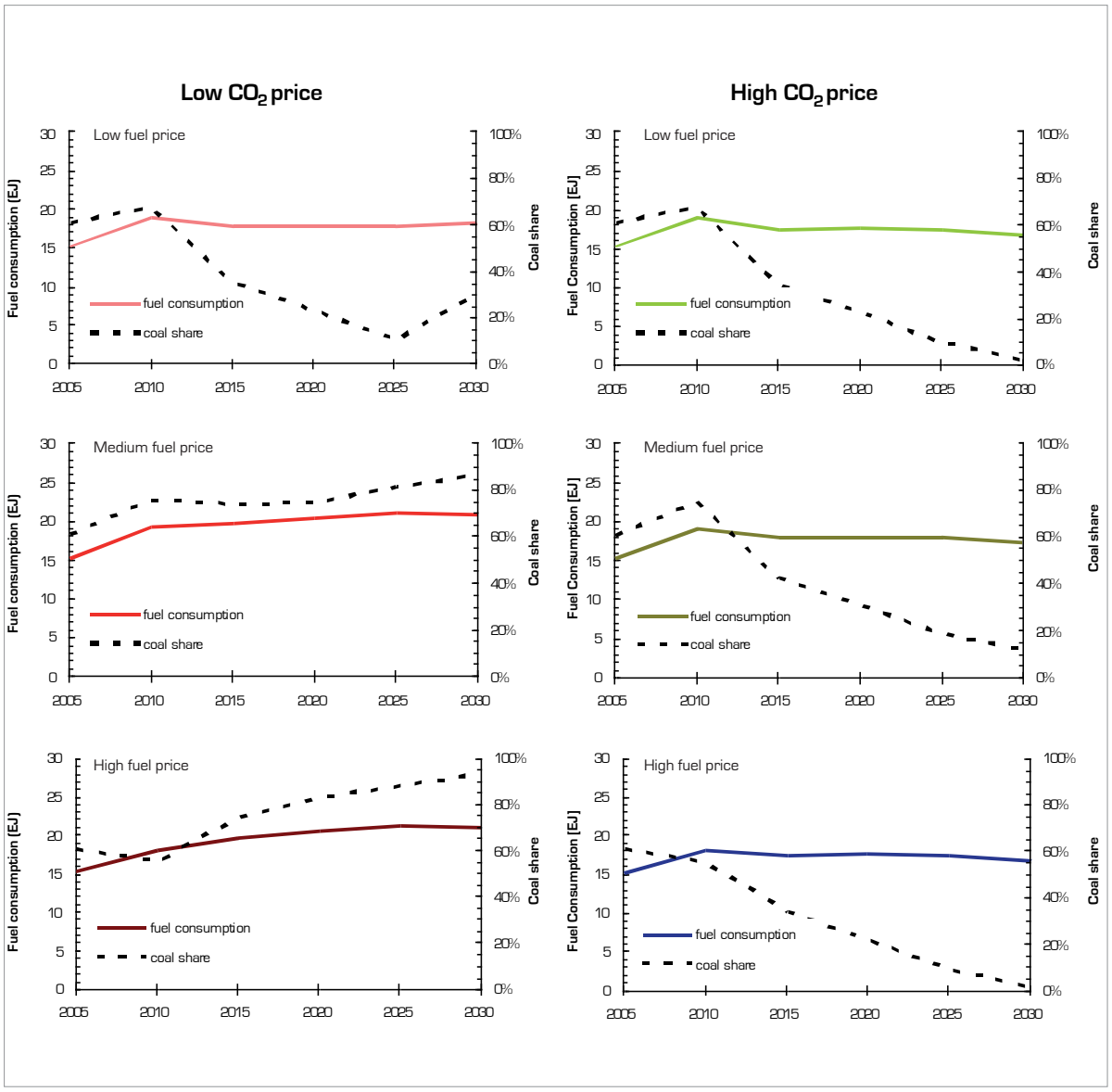

Figure 6.11: Annual fuel requirements and the respective coal share (in terms of energy content) in the fuel mix for the BAU no CCS case given different combinations of fuel and carbon prices.

fuels increases by 41.5% between 2005 and 2030 according to the assumptions of the BAU case.

Figure 6.12 shows how annual fuel consumption and the share of coal in the fuel mix change if carbon capture technology becomes available. When *CO_2 prices are low* there is no difference between the *CCS case* and the *no CCS case* (as shown in the left-hand columns of Figure 6.11 and Figure 6.12), because the conditions are unfavourable for the introduction of CCS technology. However, if *high CO_2 prices* are assumed then plants with CCS are preferred for power generation after 2020. This in turn leads to increased fuel consumption and coal use for *medium and high fuel price scenarios* compared to the *no CCS case*. The share of coal in the fuel mix ranges from 71% to 82% in 2030 while fuel consumption rises by 36% to 56% and could reach 24 EJ by 2030.

For *low fuel prices*, NGCC plants with CCS have a large share in the capacity and therefore coal's share is lower, reaching 25% of the fuel mix and the increase in fuel consumption is smaller, at 28% over the 2005 level. Note that, unlike the scenarios displayed in Figure 6.11 when CCS was not available, here it is the high and not the low carbon price scenarios that display higher increases in fuel consumption. This is due to the penetration of the less efficient CCS technologies.

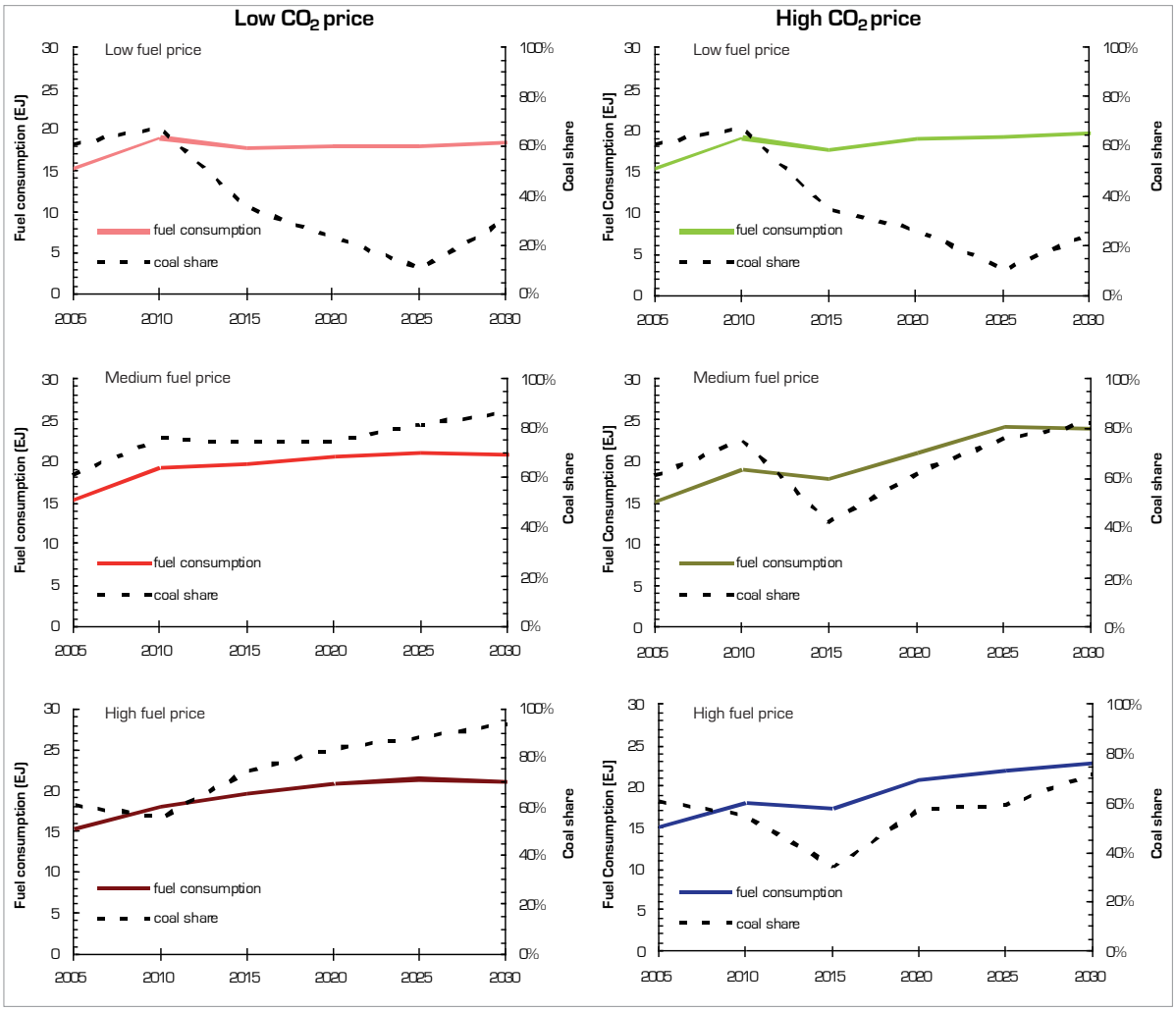

Figure 6.12: Annual fuel requirements and the respective share of coal (in terms of energy content) in the fuel mix for the BAU CCS case under different fuel and carbon price combinations.

6.3.2 Cumulative fuel consumption

The total fuel consumption for the period from 2005 to 2030 in the *BAU case* ranges from 440 EJ to 510 EJ[19] as shown in Figure 6.13. The minimum is observed for the combination of *high CO_2 and fuel prices* and *no CCS option*, while the maximum fuel consumption occurs when there are *medium fuel prices, the CO_2 price is high and CCS is deployed*. Comparison of the scenarios with the same fuel and CO_2 price assumptions reveals that there is a 5% difference in total fuel consumption when NGCC-CCS is introduced to the fleet and a 14% difference in the case of IGCC-CCS.

Figure 6.14 and Figure 6.15 give the contribution of coal and natural gas to the total fuel consumption as an absolute value and as a percentage respectively[20]. When *CCS* technology is not deployed, natural gas is predominant in the fuel mix except for the two scenarios comprising *low CO_2 prices* and *high/medium fuel prices*. The implementation of CCS maintains coal as the fuel of choice for electricity generation except *for low fuel price scenarios*, where natural gas still prevails.

19 If annual fossil fuel consumption for power generation were to remain stable at the 2004 level (15.4 EJ), the cumulative fuel consumption to 2030 would be about 385 EJ [11].

20 For reference, if natural gas consumption for the period to 2030 were to remain constant at the 2004 level [11], the cumulative consumption would be 120 EJ.

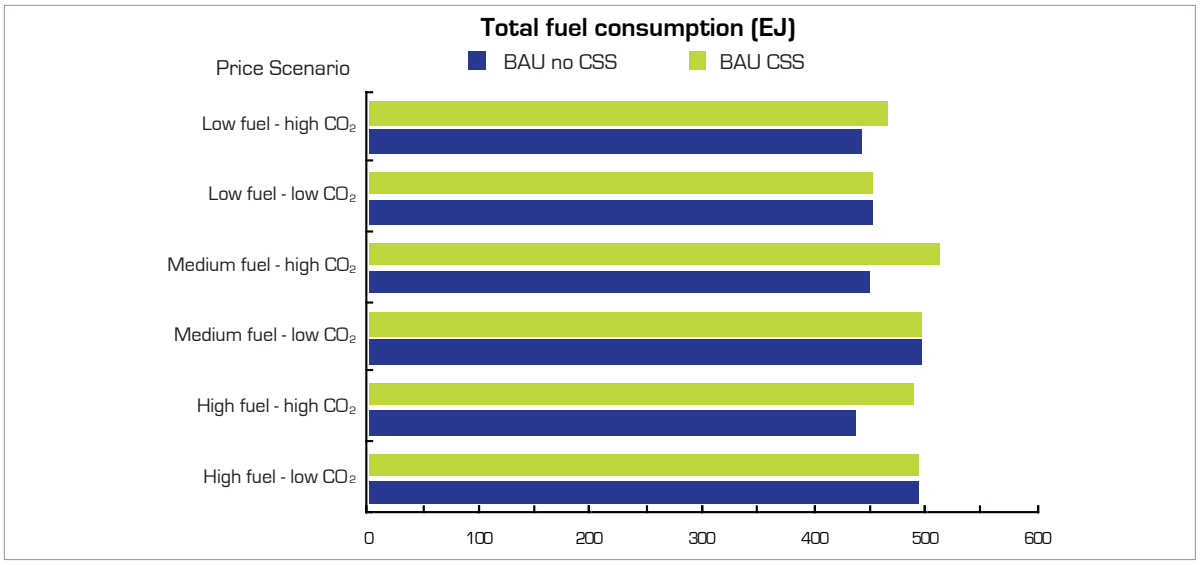

Figure 6.13: Cumulative fossil fuel consumption for electricity generation to 2030 under the BAU case for different fuel and carbon price combinations.

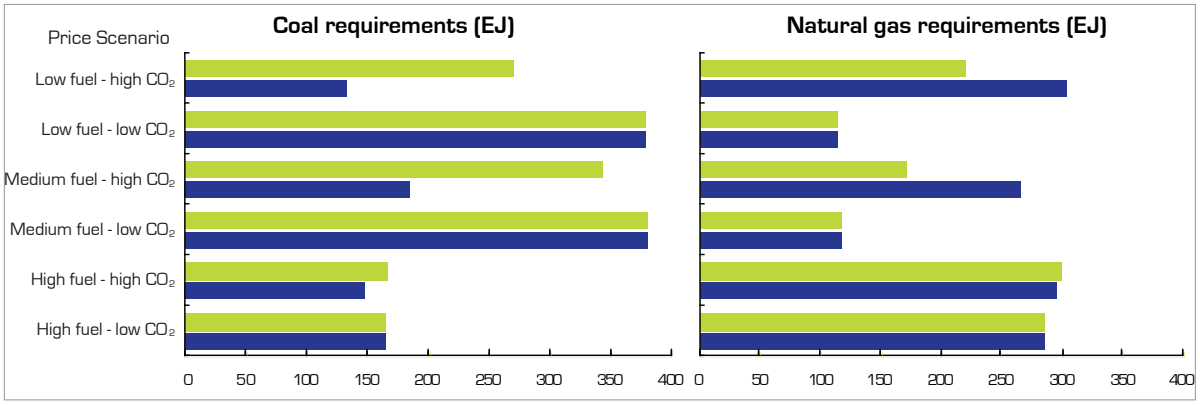

Figure 6.14: Cumulative coal and natural gas consumption for electricity generation to 2030 under the BAU case for different fuel and carbon price combinations.

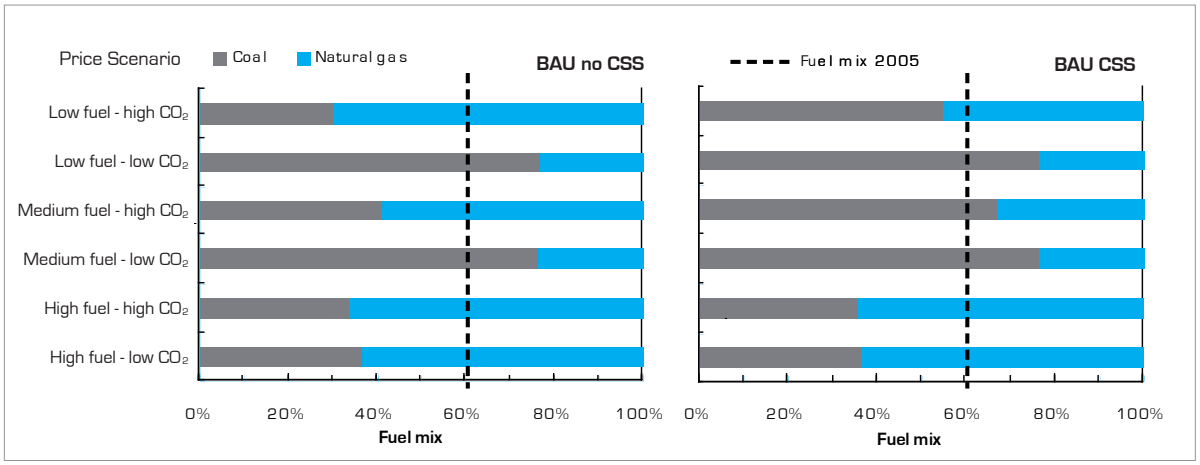

Figure 6.15: Share of coal and natural gas in the cumulative fuel consumption for fossil-fuelled power generation to 2030 under the BAU case for different fuel and carbon price combinations.

6.3.3 Fuel diversification

Fuel diversification is another contributing factor to the assessment of the security of fuel supply for the electricity generation sector. A point of departure for the European energy policy is to limit the EU's external vulnerability to imported hydrocarbons. This purpose is served by a decrease in the contribution of natural gas in power generation, which implies an increase in coal utilisation. The projected trends for the share of coal in power generation, plotted in Figure 6.11 and Figure 6.12, are presented again below in Figure 6.16. The fuel mix becomes less dependent on natural gas in the long term in *the high and medium fuel price scenarios combined with either low CO_2 prices or high CO_2 prices and CCS deployment*. However, even

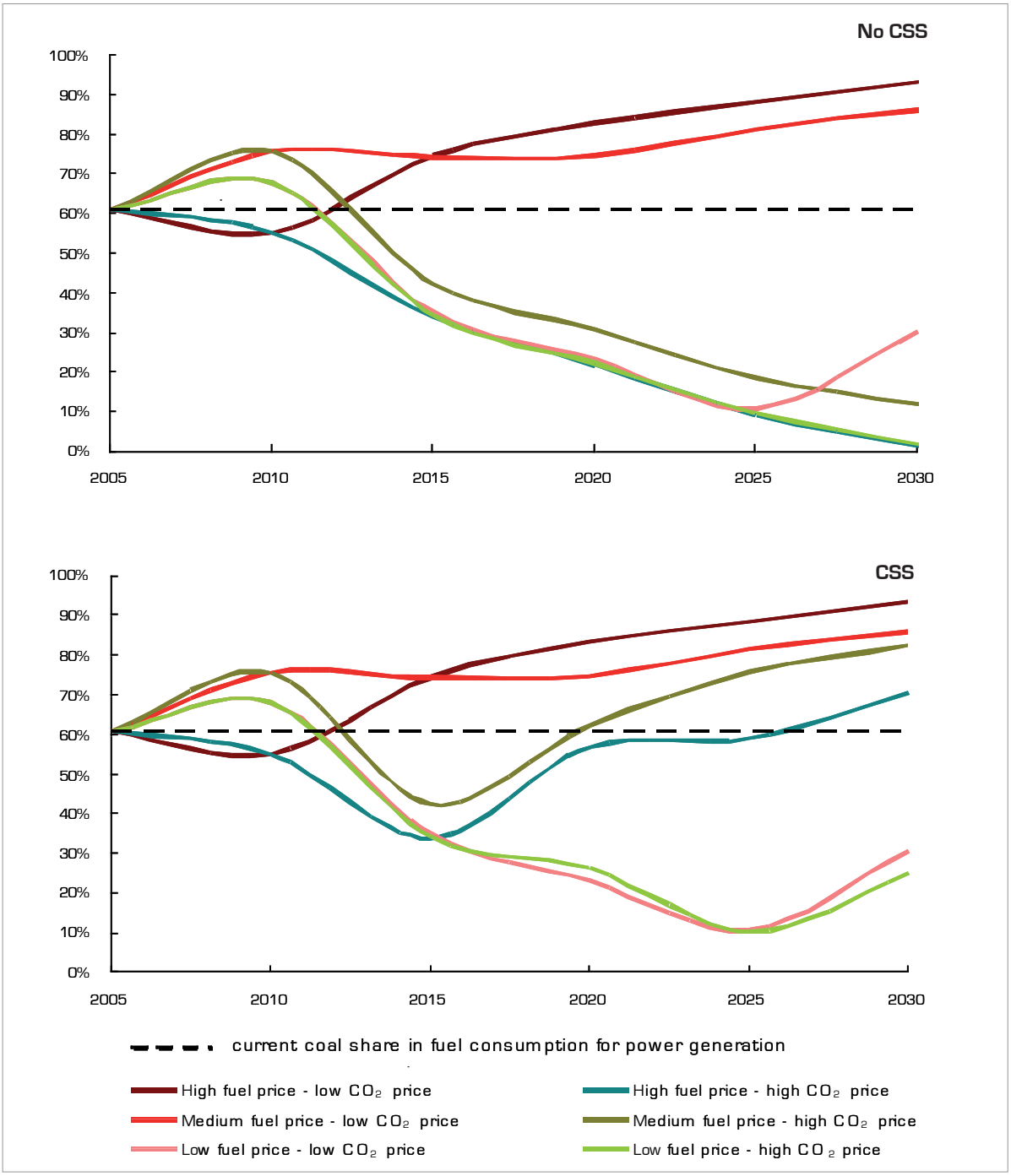

Figure 6.16: Evolution of coal's share in annual fuel consumption in the BAU case for different fuel and carbon price combinations. Scenarios where coal's share remains within the highlighted area for the period from 2005 to 2030 have a more balanced fuel mix.

in these cases the system may present weak periods of increased dependence on gas (*high* or *medium fuel price, high CO_2 price* and *CCS* around 2015), or overdependence on coal (*high* or *medium fuel price, low CO_2 price)*.

Even though a fuel mix with a reduced dependence on natural gas is more in line with European energy policy efforts to promote security of supply, the actual share of each fuel may have to be decided according to the availability of indigenous fuel resources and the situation on the international fuel markets.

6.3.4 Fuel costs

The estimated fuel costs for the fossil-fuelled power generation sector for the period from 2005 to 2030 are displayed in Figure 6.17. The natural gas price

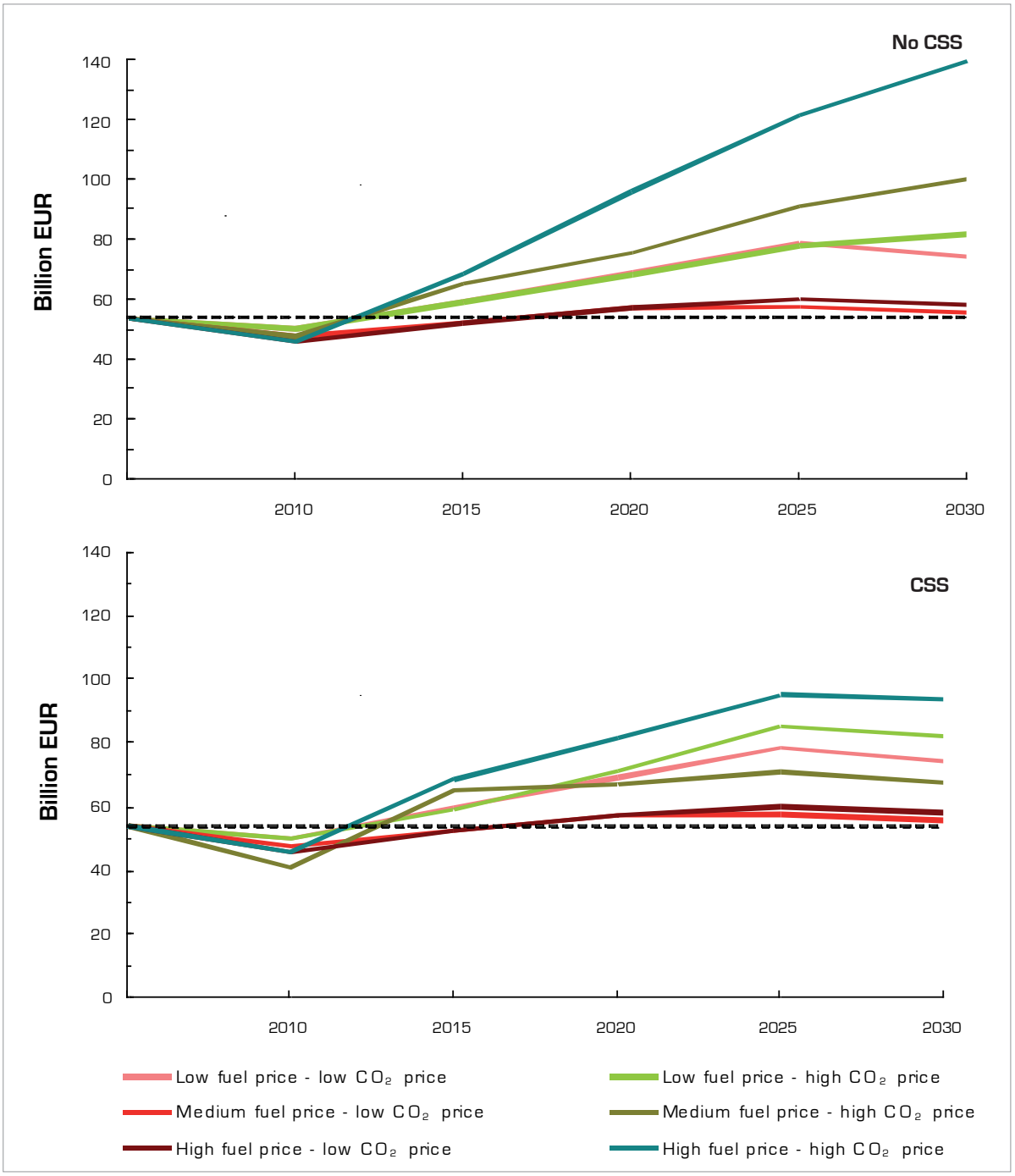

Figure 6.17: Annual fuel costs for fossil-fuelled power generation in the BAU case for different fuel and carbon price combinations.

of EUR 3.6/GJ assumed for 2010 in the *high fuel price scenarios* is in fact lower than the actual 2005 market price of EUR 4/GJ. As the 2005 prices are used to calculate a starting point based on the last available statistics [11] (the estimate for fuel costs in 2005 is EUR 54 billion), fuel costs appear to go down initially in the respective scenarios. Additionally, statistics report that 8% of the fuel of the power sector is based on petroleum products, which are now replaced in this study by either natural gas or coal. This is another reason for the initial (artificial) drop in fuel expenditure.

As expected, where coal has a large share in the fuel mix (i.e. *low CO_2 price scenarios combined with medium/high fuel prices*), fuel costs remain relatively stable after the initial adjustment in the period from 2005 to 2010. Annual fuel expenditure in 2030 is a little less than EUR 60 billion and, like capacity and fuel consumption results, does not change with the availability of *CCS* technology. When *CO_2 prices are high and CCS technology is not deployed*, natural gas has a high penetration in the fuel mix and this drives fuel expenditure to a 50% to 160% increase compared to the 2005 estimate, reaching EUR 140 billion by 2030. However, when *CCS* is deployed, annual fuel costs are moderated in these scenarios.

Due to the large price difference between coal and natural gas, the scenarios with the highest fuel consumption are not necessarily the ones with the highest fuel costs. In fact, Figure 6.18, which displays the cumulative fuel cost, displays a trend more similar to that of the natural gas requirements (right-hand side of Figure 6.14), rather than that of the cumulative fuel consumption in Figure 6.13. There are significant differences between the various scenarios, with the *medium fuel – low CO_2 price scenario* having the lowest cumulative expenditure of approximately EUR 1 300 billion in both the *CCS* and *no CCS* cases, and the *high fuel – high CO_2 price scenario* being the most expensive with the expenditure reaching EUR 2 100 billion. In terms of total fuel costs between 2005 and 2030, under the same fuel prices, the *CCS* case is associated with a fuel expenditure that is 15% lower than the fuel expenditure in the *no CCS* case, when IGCC is the technology deployed. When NGCC with CCS is the technology of choice, fuel expenditure increases slightly by 3%.

6.4 Carbon dioxide emissions

This study only examines CO_2 emissions from fuel combustion at the plant. Any emissions arising from fuel extraction and transport as well as emissions from CO_2 transport and eventual storage have not been considered.

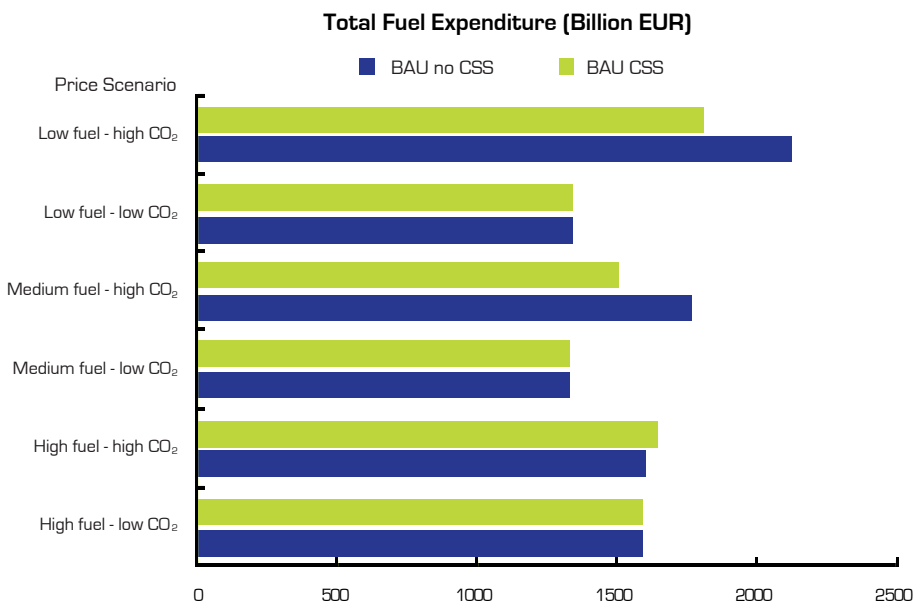

Figure 6.18: Cumulative fuel expenditure during the period to 2030 in the electricity generation sector under the BAU case for different combinations of fuel and carbon prices.

As stated in Chapter 2, a key decision from the European Council is the 20% reduction in greenhouse gas emissions in the EU by 2020 compared to 1990 levels. In order for this target to be realised, CO_2 emissions from fossil-fuelled power generation will have to be reduced by at least this amount, if not more.

Figure 6.19 shows the calculated trend in annual CO_2 emissions from fossil-fuelled power generation in the *BAU case* under the assumptions of the study. Common to *all scenarios* is an increase in emissions up to the year 2010. This is a result of increased reliance on coal for fossil-fuelled power generation in that period. As previously shown (Figure 6.4 and Figure 6.6), the majority of the total power generation capacity during that time consists of coal-fired power plants, which take up most of the load. Fossil-fuelled power generation increases by 12% in that period due to overall rising demand and the limited contribution of non-fossil power generation. At the same time the

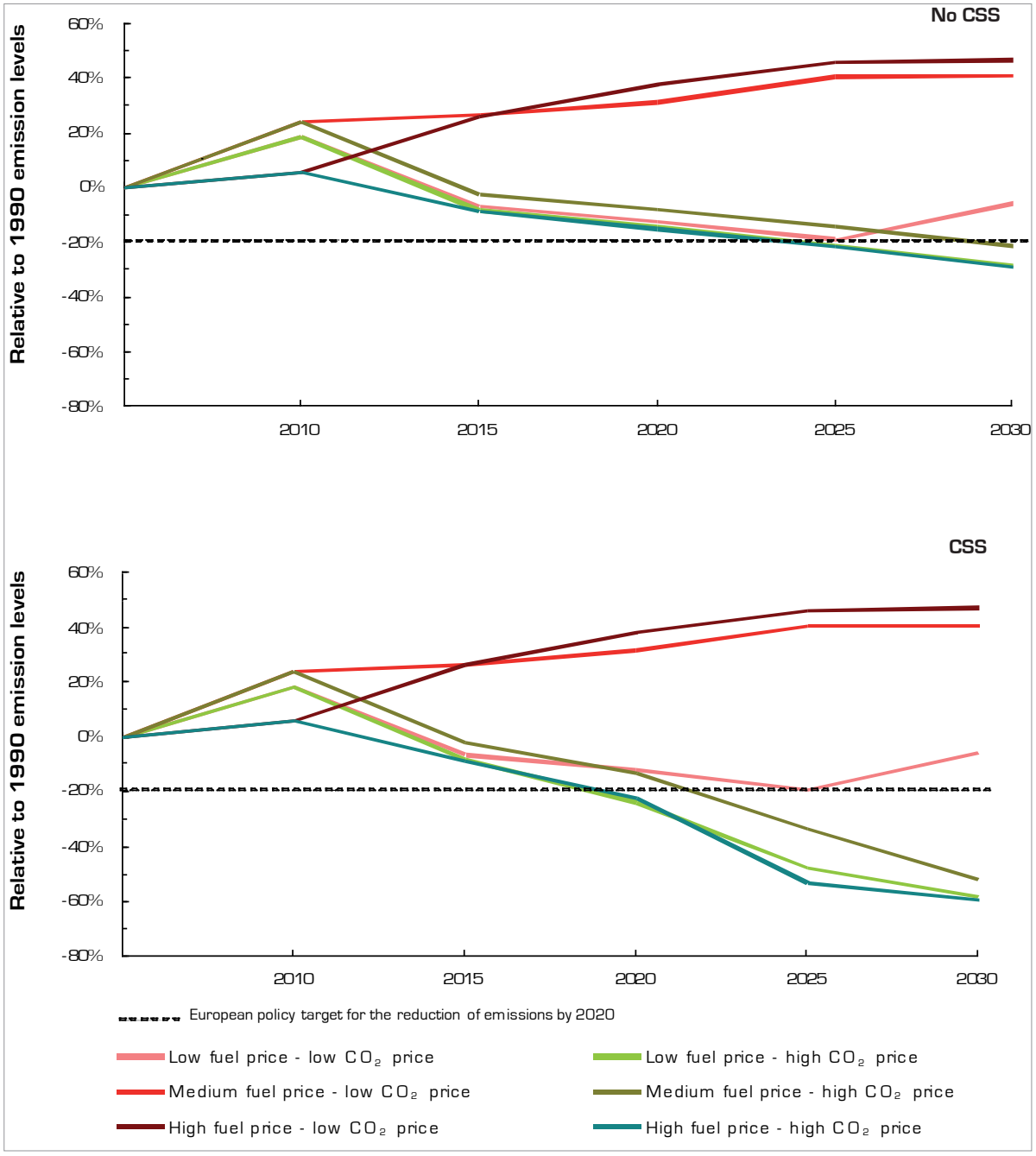

Figure 6.19: Annual emissions from the electricity generation sector compared to the 1990 emissions level in the BAU case for different fuel and carbon price combination scenarios.

share of electricity generated from coal ranges between 46% and 70% of the total fossil-fuelled generation depending on the economic parameters of the different scenarios. The fact that the model overestimates the power generated in that period compared to the original assumptions for electricity demand (see Section 4.7.2) may exaggerate the effect on the emission levels.

After the initial increase, the change in the CO_2 emission levels is mainly dictated by the contribution of coal technologies in each scenario. Thus, for *low CO_2 price scenarios combined with medium or high fuel prices,* the increasing trend in CO_2 emissions continues and by 2030, CO_2 emissions are between 40% and 50% higher than the 1990 benchmark. For *high CO_2 price scenarios,* CO_2 emissions start to decrease after 2010 and CCS becomes the deciding factor on whether the aforementioned reduction target of 20% is met or not. In the *BAU scenarios where CCS is not deployed* the reduction target is not reached in time even though *high CO_2 prices* could reduce emissions below the 20% level by 2030. In the *BAU scenarios where CCS technologies are deployed,* the target of reducing emissions by 20% by 2020 is only reached when *high CO_2 prices* in combination with *high or low fuel prices* are assumed, as this discourages the introduction of new PC capacity in the fleet. The 20% reduction target is almost met in the case of *medium fuel prices*.

A greater reduction achieved in terms of annual emissions by 2030 does not necessarily result in a better performance (in terms of CO_2 emissions) throughout the period covered by the analysis. Figure 6.20 shows the estimated cumulative emissions from fossil-fuelled electricity generation for the period from 2005 to 2030. The minimum cumulative emissions are observed for *high fuel and CO_2 prices and the implementation of CCS* (26.6 Gt). *Low CO_2 price scenarios* result in high CO_2 emissions, reaching a total of 43.5 Gt for the same period. The amount of CO_2 captured in the period to 2030 is 3.0 Gt, 6.7 Gt and 6.4 Gt for the low, medium and high fuel price scenarios respectively. These figures indicate the magnitude of CO_2 storage capacity required in the case of CCS deployment.

In summary, if the BAU case is assumed concerning the contribution non-fossil fuel sources to power generation, emissions from the power sector can only be reduced to 20% below 1990 levels by 2020 with the commercialisation and deployment of CCS technology. Furthermore, the economic parameters will have to favour the introduction of NGCC technology to the fleet in significant shares and discourage the introduction of new PC plants prior to CCS deployment. This means *high CO_2 prices* and fuel price ratios that make gas-based technologies more competitive than alternative power generation technologies are needed.

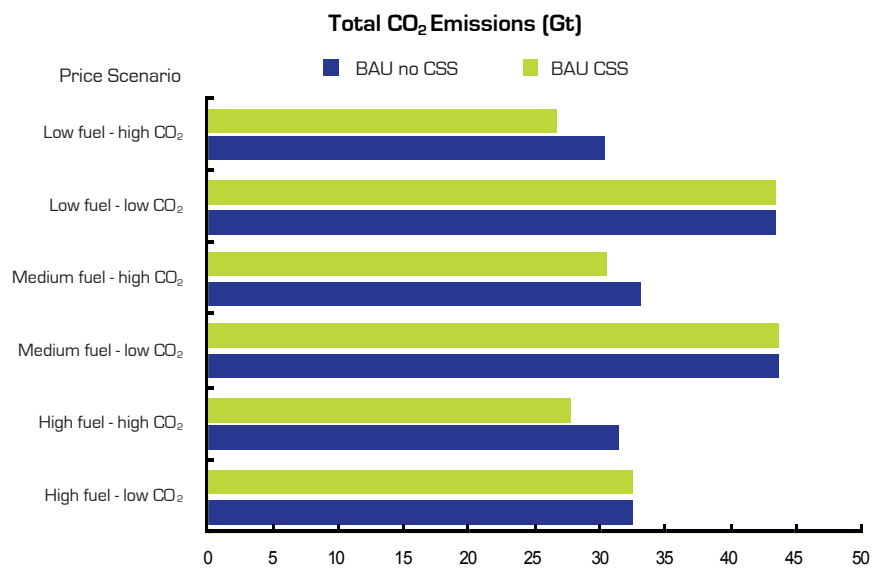

Figure 6.20: Cumulative CO2 emissions from the electricity sector during the period from 2005 to 2030, for the BAU case for different fuel and carbon price combinations.

6.5 Average production cost of fossil-fuelled electricity

This section examines how the technology choices made in each scenario translate into costs for the production of electricity from the fossil fuel fleet that will ultimately be transferred to the consumer. The starting point for 2005 is a cost of 0.045 EUR/kWh, which is an estimate derived from applying the reported fuel prices (see Section 4.5.1) to the power generated by the fossil fuel power plant fleet as it stood in 2005 after re-grouping the capacity according to Section 5.3. All figures reported hereafter refer to average production costs for fossil-fuelled electricity only.

As shown in Figure 6.21 when *CO_2 costs are low*, electricity production costs are also low, remaining

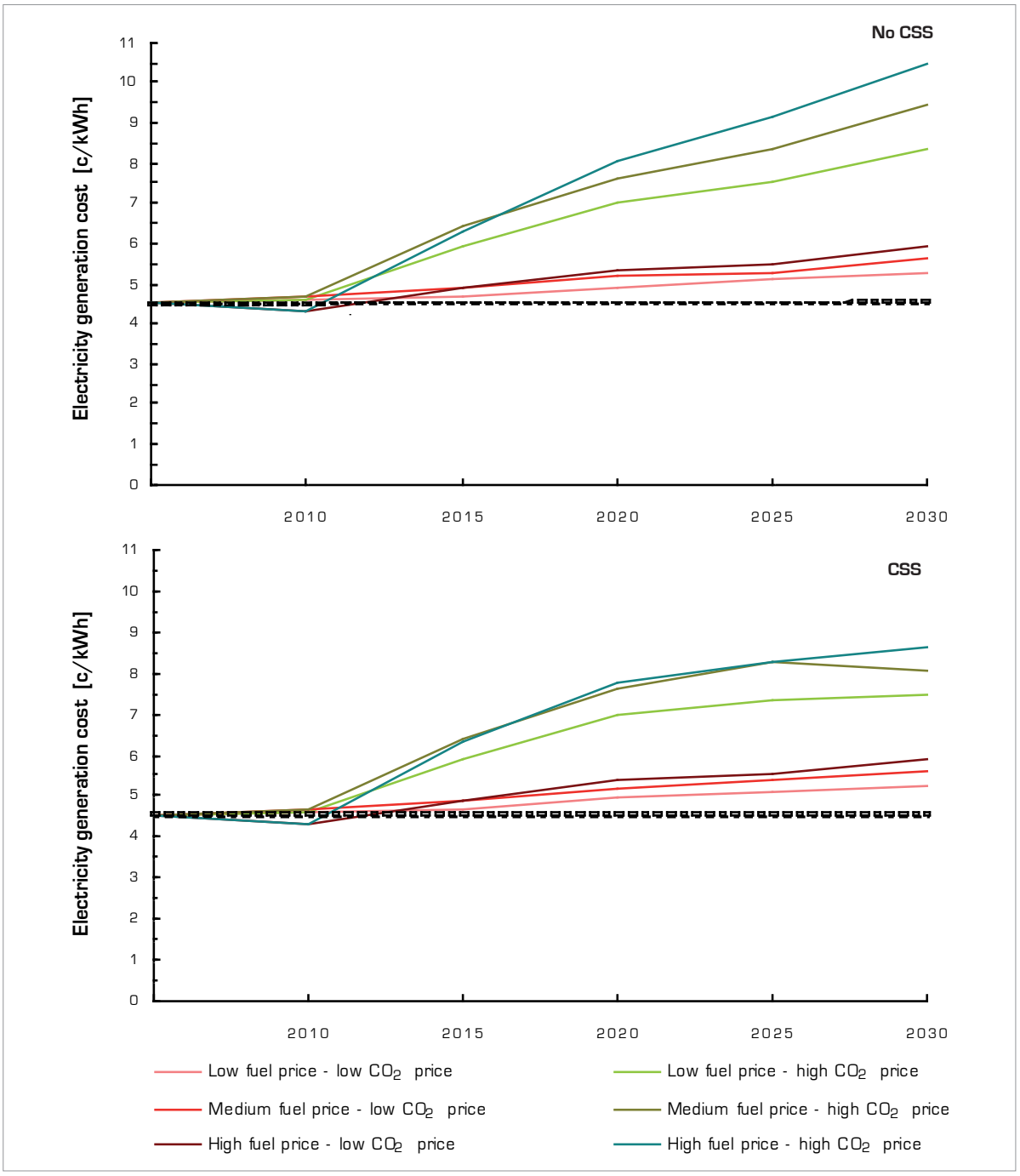

Figure 6.21: Estimated average fossil fuel electricity production cost in the BAU case for different fuel and carbon price combinations.

below 0.06 EUR/kWh for the period from 2005 to 2030. However, when *CO_2 prices are high,* power production becomes more expensive irrespective of the availability of CCS technology. When *CCS is not an option*, the high cost of electricity is due to CO_2 penalties and the increased use of natural gas. On the other hand, assuming that there will be no major breakthroughs in technology development during the time period of the study, *CCS* based on coal is inherently more expensive and inefficient. While the cost components may be different, the effect is the same: electricity production costs more than double by 2030. Up to the period from 2020 to 2025, the increase is comparable for the *CCS* and the *no CCS case*. However, in the last five-year period costs rise more sharply *if there are no CCS options* and end up in the range of 0.083 EUR/kWh to 0.105 EUR/kWh. This is 11% to 22% higher than for the respective *CCS scenarios* in 2030, where costs reach from 0.073 EUR/kWh to 0.083 EUR/kWh.

7 The Low Carbon Policy Case: Fossil Fuel Power Plant Park Composition and Impacts

This chapter investigates the evolution of the fossil fuel capacity in the *low carbon policy case* where nuclear and RES are strongly promoted in power generation at the expense of fossil fuel technologies. The presentation of the results follows the order used in the previous chapter.

7.1 New capacity required

In the *policy case*, the fossil fuel power plant capacity that needs to be operational in 2030 to meet the forecasted demand for electricity is increased to 570 GW from the 400 GW in operation in 2005 (see Figure 7.1). Hence, the additional fossil fuel power plant capacity needed is 170 GW. Due to the high penetration of non-fossil-fuel power generation technologies that has been assumed, this amounts to 57% of the additional capacity required in the BAU case. As the installed capacity is reduced from 400 GW in 2005 to 60 GW in 2030 due to the retirement of old plants, the new fossil fuel power plant capacity that needs to be constructed by 2030 is 510 GW (see Figure 7.2), which is 80% of the new capacity requirements in the BAU case.

Not unlike the BAU case, the most intensive time for building new capacity is the period from 2005 to 2010, when approximately 200 GW are built, mostly to replace old power plants that have exceeded their nominal technical lifetime. As in the BAU case, this is more a reflection of the fact that a part of the fleet has passed its assumed retirement age rather than a real picture of ongoing construction.

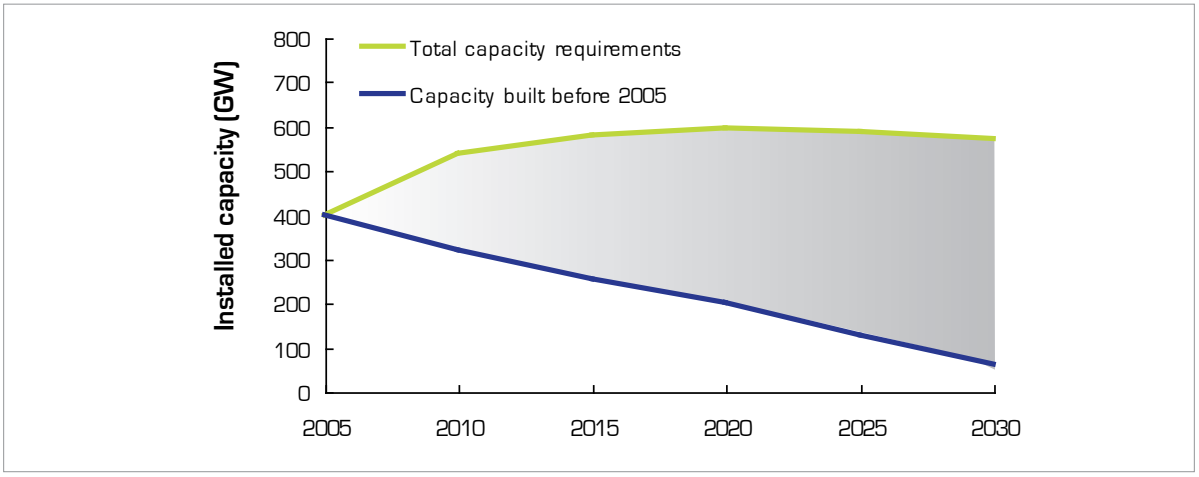

Figure 7.1: Evolution of the operating capacity of power plants built before 2005 and the total capacity requirements in the policy case. The height of the highlighted area represents the new capacity needed.

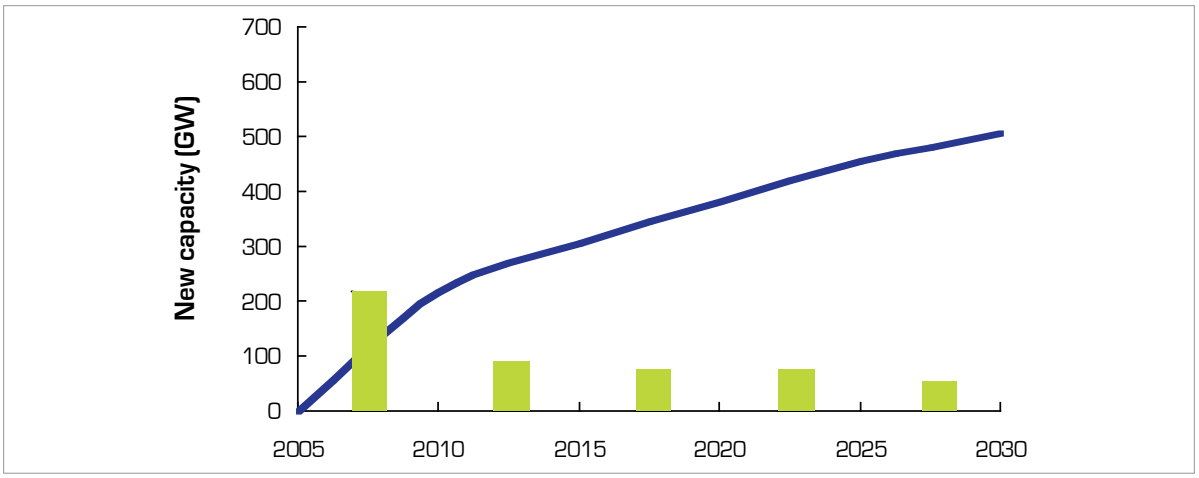

Figure 7.2: Requirements for new fossil fuel power plant capacity to 2030 in the policy case. The continuous line shows the cumulative new capacity needed while the bars indicate the capacity that needs to be built up during each five-year period.

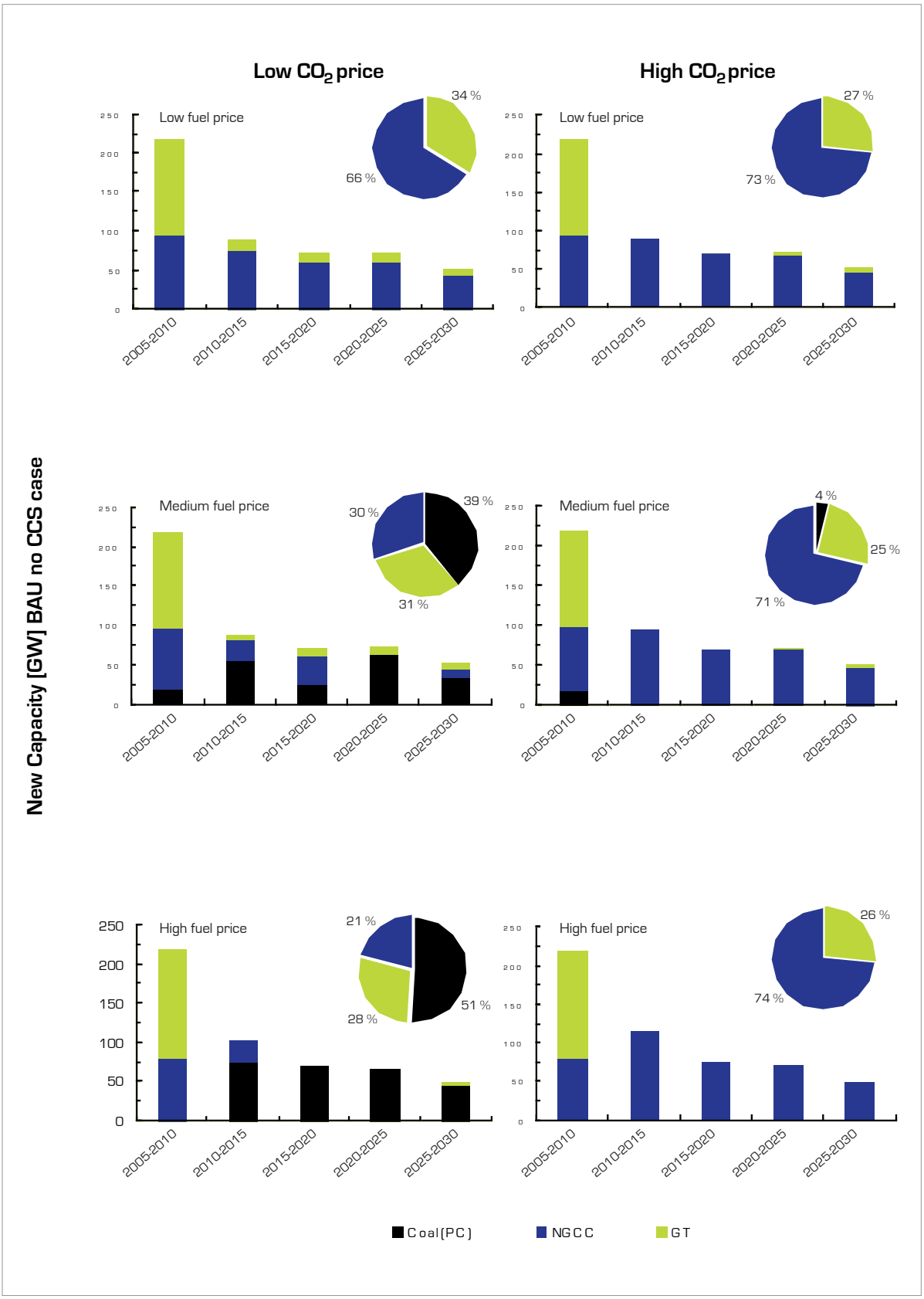

Figure 7.3: New capacity requirements by technology in the policy no CCS case for different fuel and carbon price combinations. The bar charts show the capacity required during each period by technology type, while the pie chart displays the share of each technology in the capacity built throughout the period from 2005 to 2030.

7.1.1 Technology mix without the deployment of CCS

The portfolio of technologies that will meet the need for new capacity depends strongly on the fuel and carbon prices. Figure 7.3 shows the contribution of power plant technologies to the new capacity in cases where carbon capture and storage technologies are not considered (*no CCS case*).

As in the *BAU case*, the open cycle gas turbine has a relatively similar penetration in *all scenarios*, varying between 25% and 34% (130–170 GW) of new capacity built during the first five-year period. The share of open cycle gas turbine capacity required in the *policy case* is 10% higher than in the *BAU case*, which can be attributed to the steeper load curve for the fossil power plant fleet.

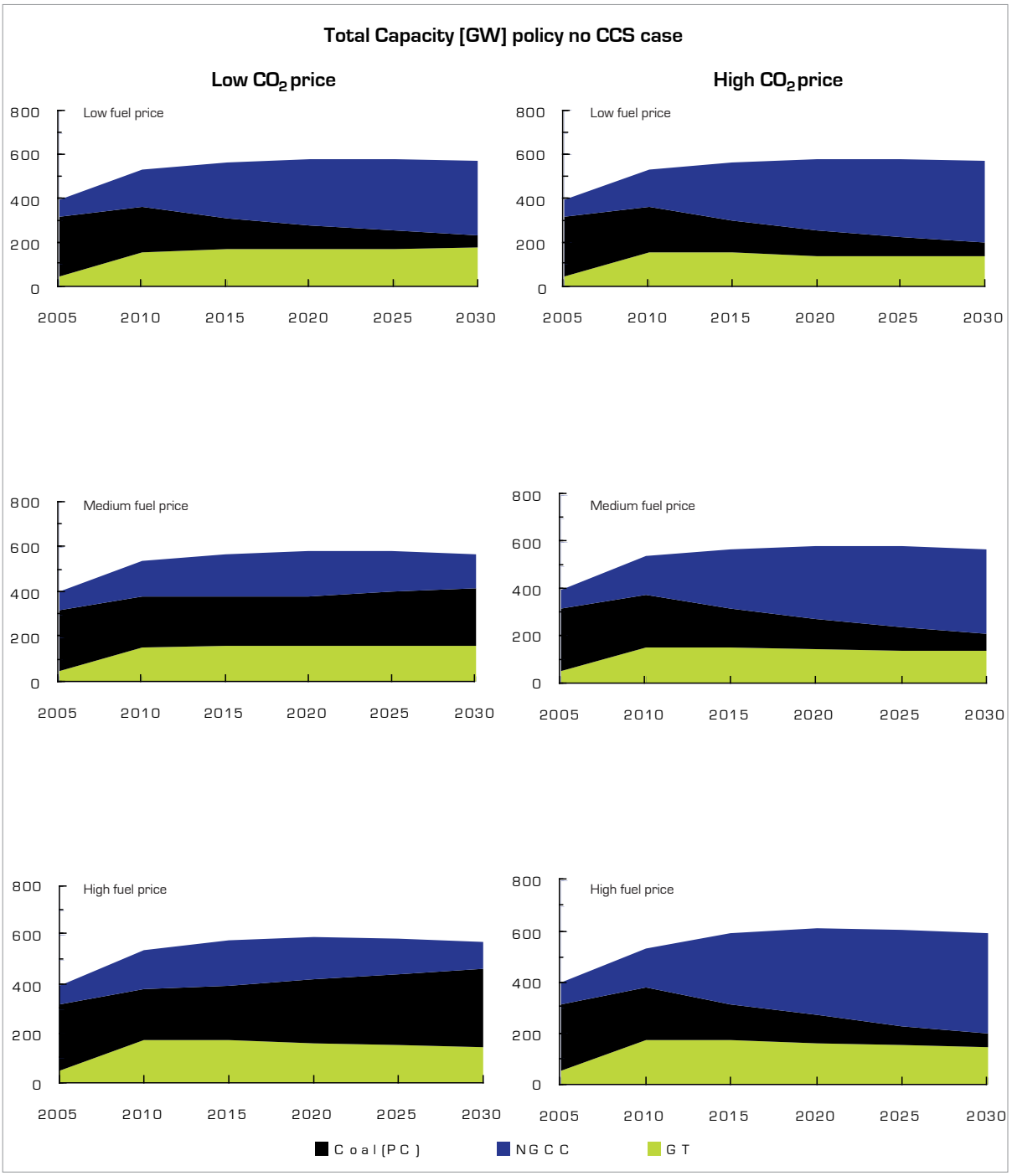

Figure 7.4: Total installed capacity by technology in the policy no CCS case for different fuel and carbon price combinations.

The penetration of NGCC and PC plants, which operate in base load or load following modes, varies significantly between scenarios. As in the BAU case, for all *high CO_2 price* (graphs in the right-hand column of Figure 7.3) *and all low fuel price scenarios*, NGCC plants dominate the new capacity. Their penetration varies between 66% and 74% of new capacity (340–390 GW), depending on the relationship between the fuel prices. Under high CO_2 prices, the role of coal technology is limited to a small fraction (4%) of the total capacity for *medium fuel prices*, with coal plants built only during the first five-year period. Compared to the BAU case, the share of NGCC in the new capacity is somewhat reduced; the difference is taken up by open cycle gas turbines as the load becomes more varied or intermittent.

This situation changes significantly when the *CO_2 price is low* and combined with *medium or high fuel prices*. In this case the penetration of PC technologies ranges between 39% (200 GW) and 59% (260 GW), depending on the fuel prices. Clearly, high natural gas prices make NGCC technology less competitive compared to coal technologies. In both these scenarios the competitiveness of the NGCC technology diminishes beyond 2015. Although the trend is the same, the share of coal technology in the new capacity is lower in the *policy case* than in the respective scenarios in the *BAU case*. This is again due to the load being more uneven and thus requiring technologies that can operate economically at reduced capacity factors.

In summary, as in the *BAU case*, *high CO_2 prices in the absence of CCS* are detrimental to the further penetration of coal power plant technologies. On the other hand, *low CO_2 prices,* when combined with *medium or high fuel prices*, favour coal technology at the expense of NGCC.

The total installed capacity in the *policy no CCS case* is shown in Figure 7.4. Open cycle gas turbines have a share of 25% to 30% in 2030, with the remainder being split between NGCC and PC technologies For *low CO_2 prices* combined with *medium or high fuel prices,* coal technologies maintain a considerable share of the total capacity to 2030 (44-55%). In all other cases, the contribution of PC to power generation decreases and the share of this technology in the total installed capacity is in the range of 9% to 12% by 2030. Compared to the corresponding *BAU no CCS scenarios,* the penetration of PC technology, in terms of its share in the total capacity, is slightly lower in the *policy case*.

7.1.2 Technology mix with the deployment of CCS

Figure 7.5 shows the technology mix of the new capacity in the different scenarios of the *policy case* provided *CCS technology becomes available* in the period from 2015 to 2020. As in the *BAU case* the availability of CCS plants does not affect the technology mix when *CO_2 prices are low*.

High CO_2 prices make CCS technology cost competitive and plants that capture CO_2 account for 37% of the new capacity built after the technology is commercialised (see the graphs in the right-hand side in Figure 7.5). For *low fuel prices,* a large fraction of the CCS plants installed are based on NGCC technology, while for *medium or high fuel prices* IGCC-CCS plants prevail. The penetration of power plants with CCS in the fleet is at the expense of conventional NGCC technology, the share of which in the new capacity drops to between 34% and 37% (compared to between 71% and 74% in the corresponding scenarios in the *policy no CCS case*).

The contribution of CCS power plants to the total capacity (shown in Figure 7.6) reaches a 33% share by 2030 in the *high CO_2 price scenarios*. In the case of *low fuel prices* this share is split between IGCC and NGCC capture plants, which in 2030 contribute 9 % and 24% to the total capacity respectively. As in the BAU case, PC CCS plants are not competitive compared to the other CCS options available and thus do not contribute to the technology mix.

The threshold CO_2 price for the introduction of CCS plants in the electricity generation system depends on the fossil fuel price. Thus the threshold prices in the *policy case* are the same as in the *BAU case* for the respective fuel price scenarios (see Table 6.1).

Similarly, the influence of absolute fuel prices and natural gas-to-coal price ratios on the composition of the new capacity is identical to that described in Section 6.1.3 (see Figure 6.7 and Figure 6.8).

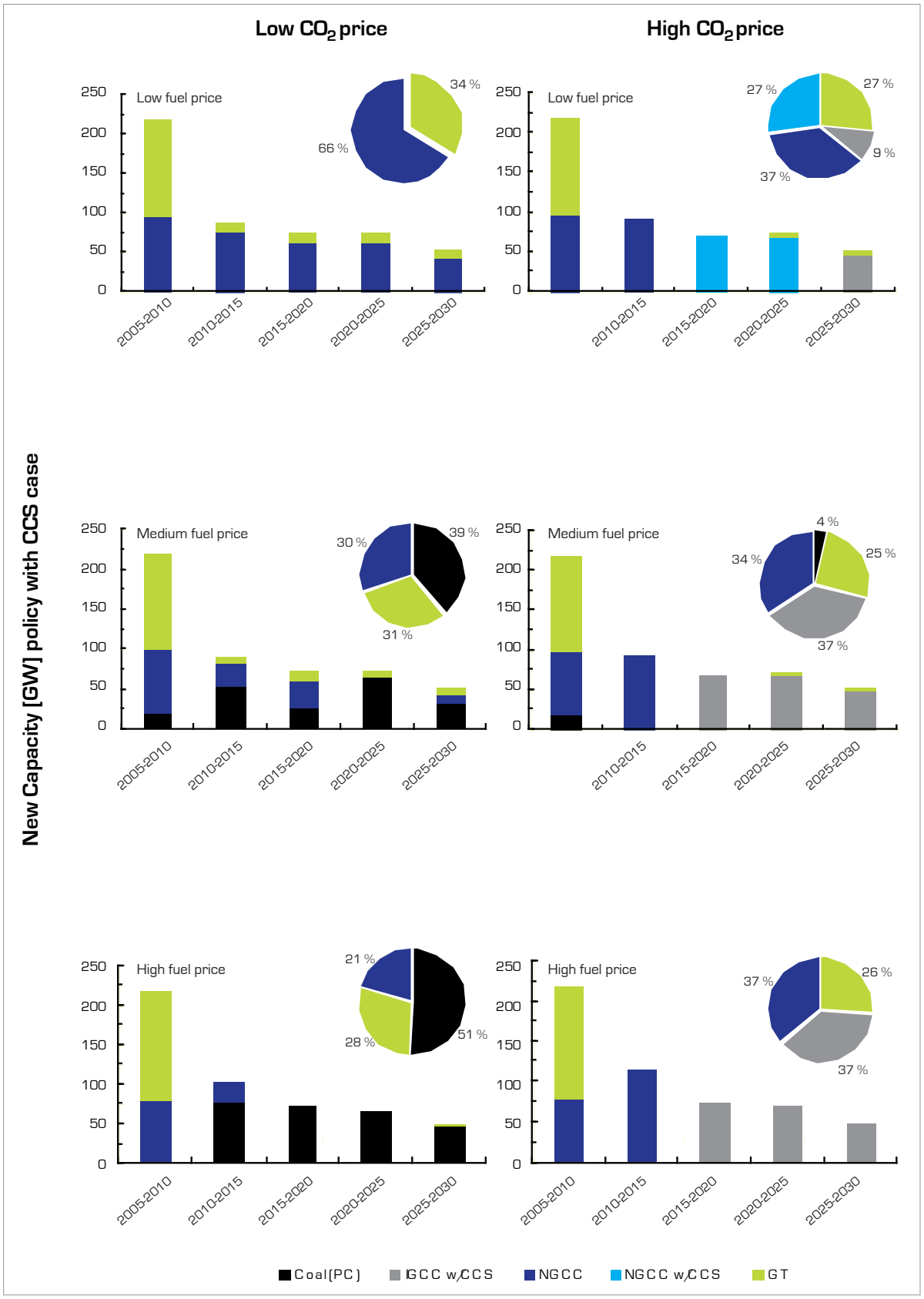

Figure 7.5: New capacity requirements by technology in the policy CCS case for different fuel and carbon price combinations. The bar charts show the capacity required in each period by technology type, while the pie chart displays the share of each technology in the capacity built throughout the period from 2005 to 2030.

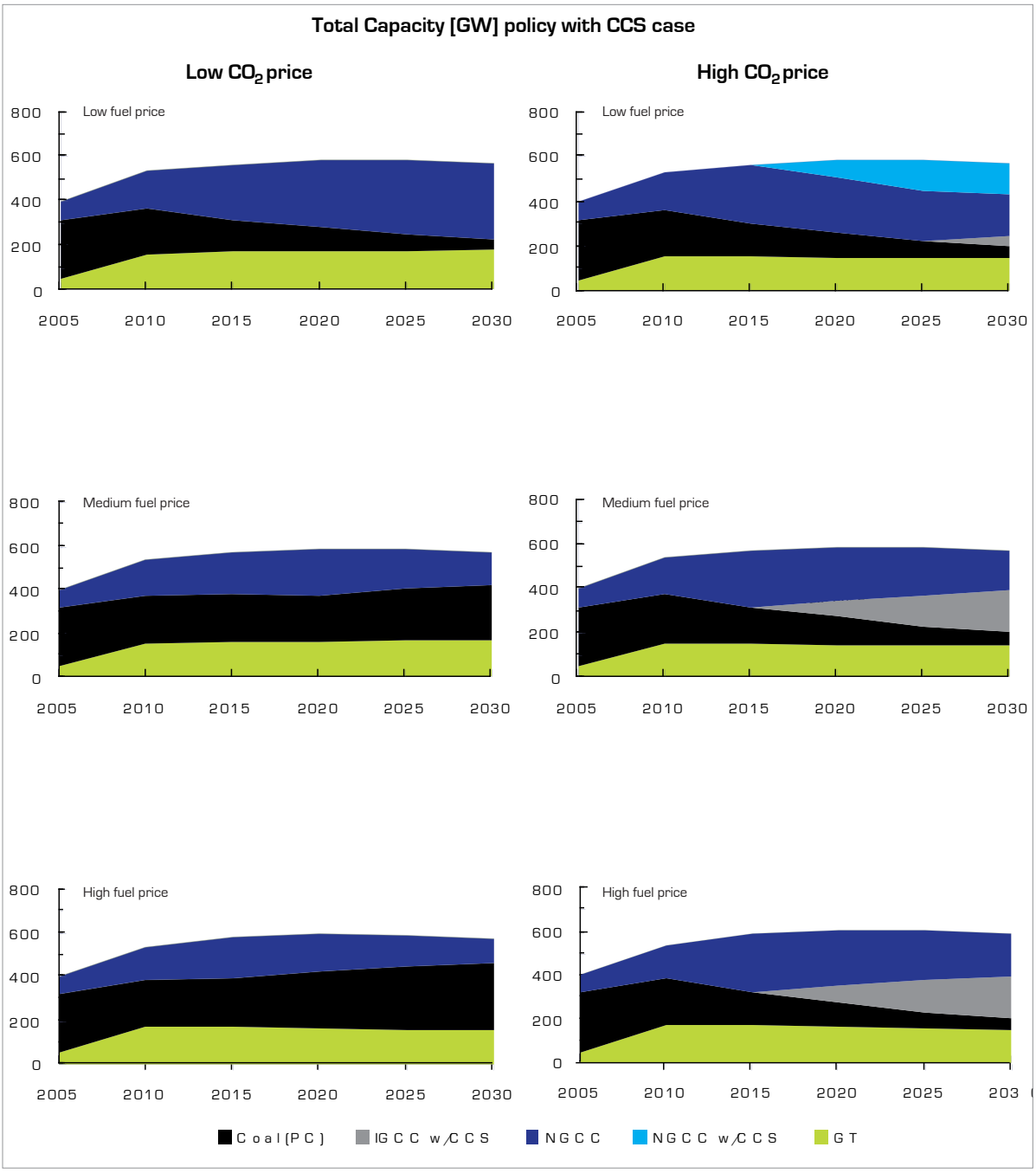

Figure 7.6: Total installed capacity by technology type in the policy CCS case for different fuel and carbon price combinations

7.2 Capital requirements

During the initial five-year period (2005-10), the required overnight capital expenditure ranges between EUR 96 billion and EUR 113 billion depending on the composition of the new power plant fleet (see Figure 7.7). Dictated by the technology mix, the capital needs increase with the share of PC in the new capacity. When no CCS plants are deployed, the capital requirements decrease beyond 2015. The decrease in the required investment is significant for *low fuel prices*, but less notable for the other fuel price scenarios due to the large share of conventional coal plants. The deployment of CCS plants during the period 2015–20 and beyond increases capital requirements. As a result, overnight capital costs nearly double for *low fuel prices* and almost triple *for medium or high fuel prices* compared to the costs in the corresponding time periods for *scenarios without CCS*.

The cumulative capital expenditure required for the build-up of new capacity in all scenarios considered in the *policy case* is summarised in Figure 7.8. When CCS options are not available, capital needs range between EUR 250 billion and EUR 400 billion (on average approximately 75% of the corresponding expenditure in the *BAU no CCS case*). The lowest figure is associated with the *low fuel - low CO_2 price scenario*, where all new capacity is based on the use of open cycle gas turbines and NGCC technology.

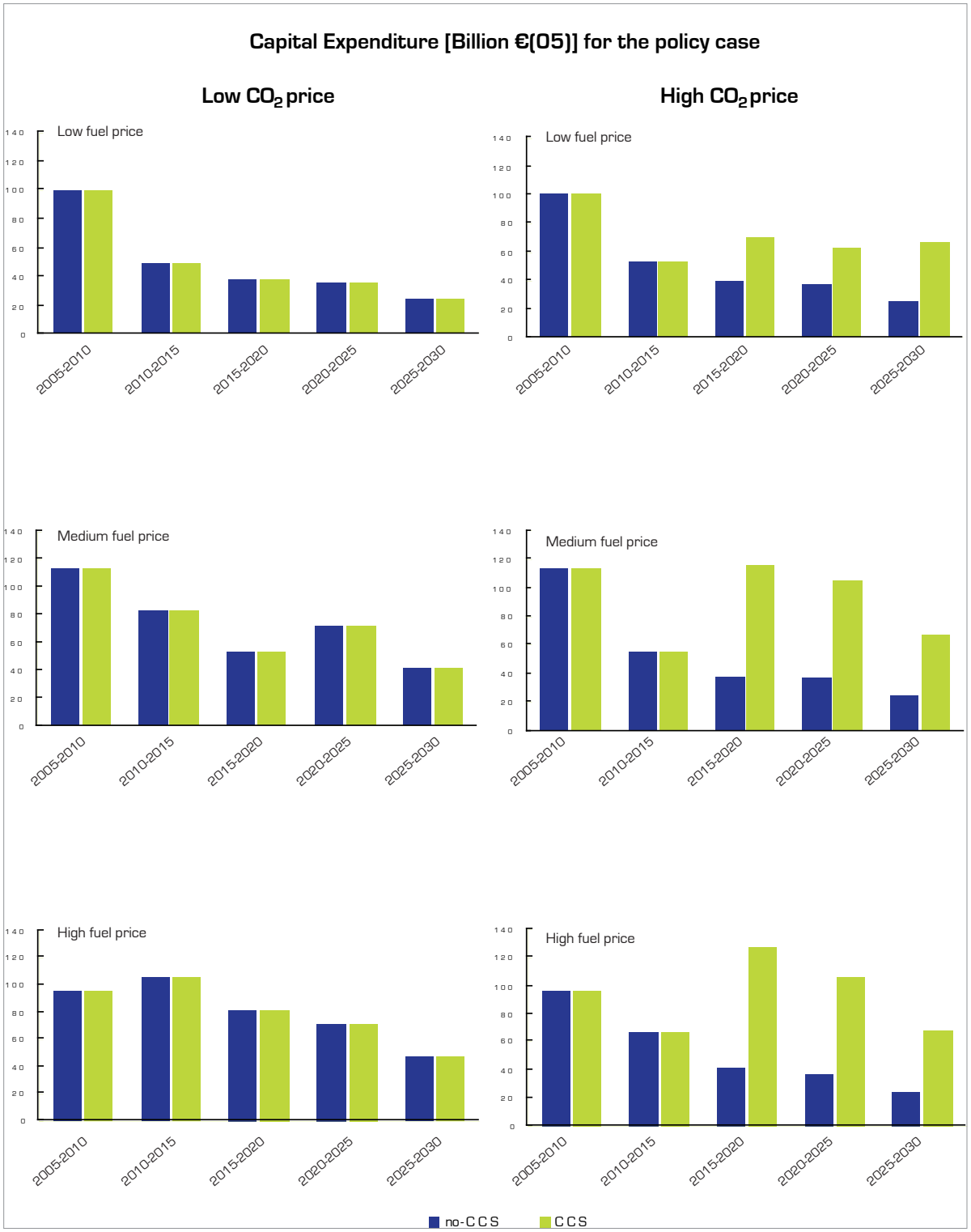

Figure 7.7: Capital requirements per five-year period for building the new fossil fuel capacity in the policy case for different fuel and carbon price combinations.

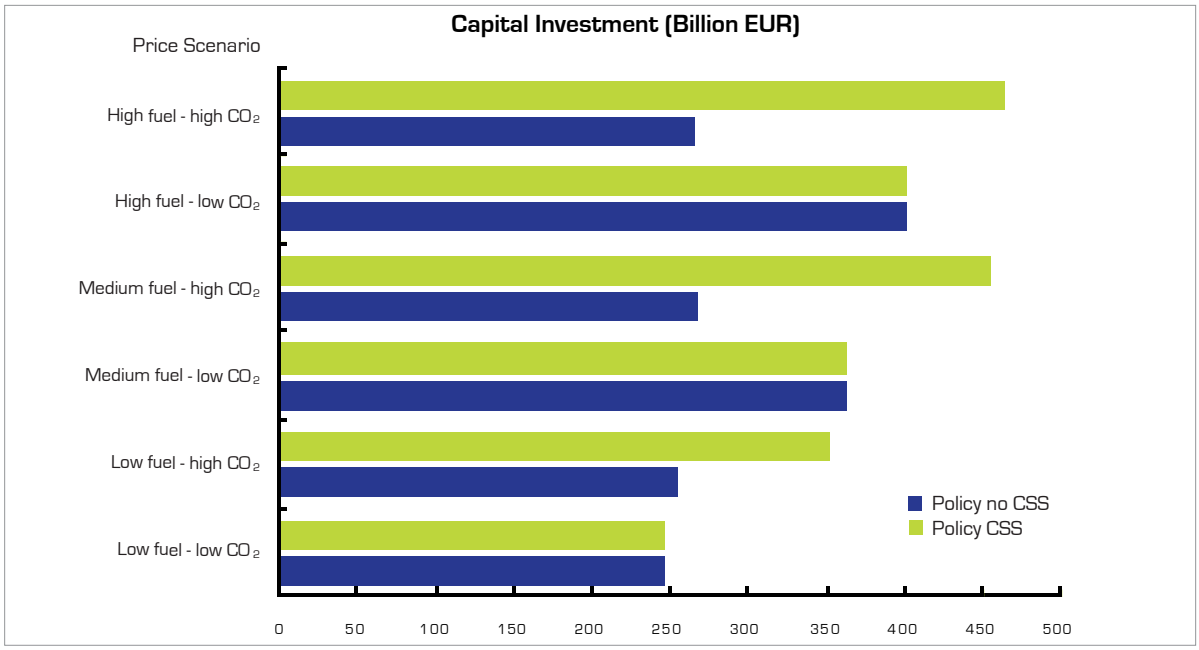

Figure 7.8: Comparison of cumulative capital expenditure required for the expansion of the fossil fuel power plant generation sector to 2030, under the policy case for different fuel and carbon price combination scenarios.

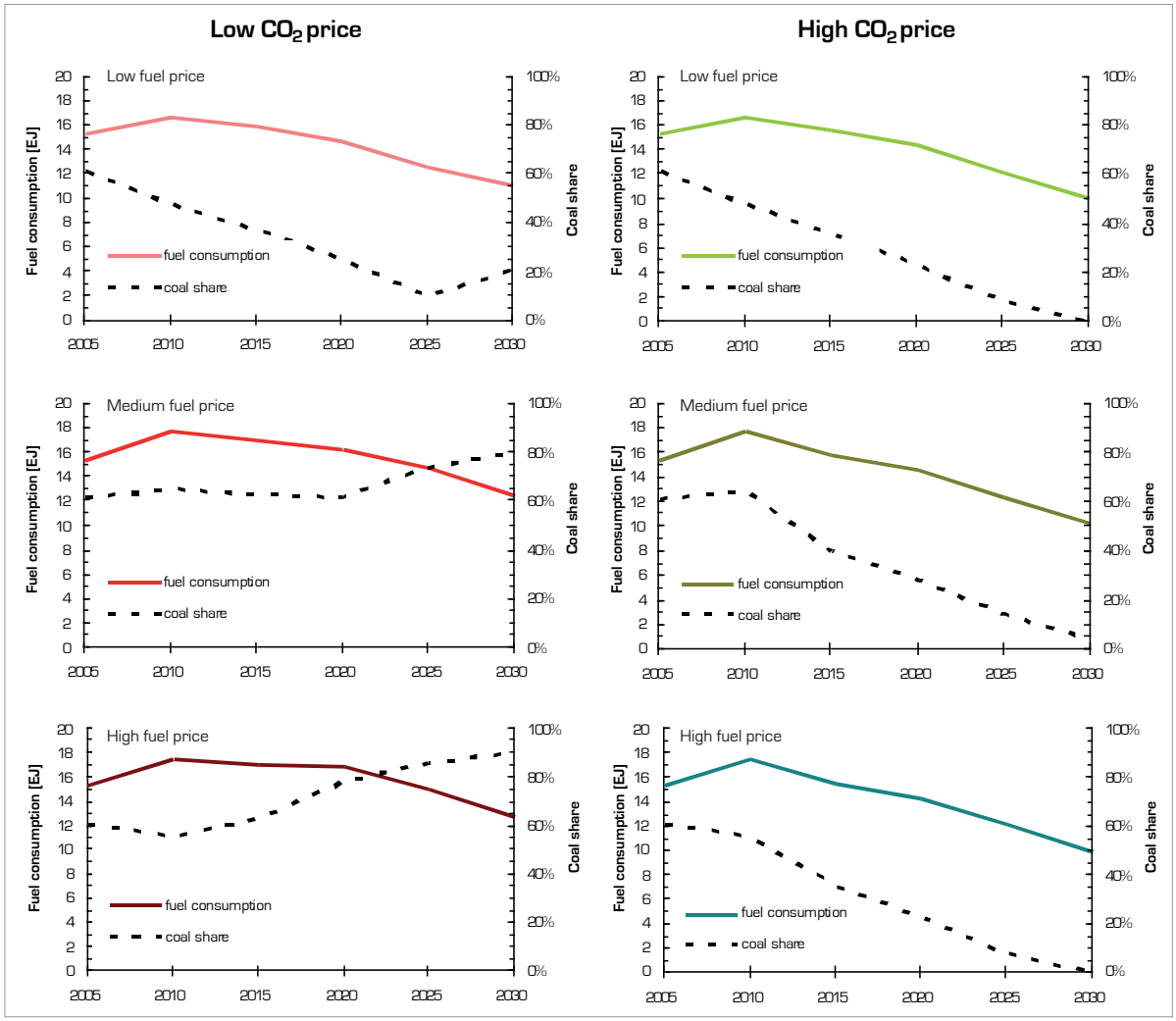

Figure 7.9: Annual fuel requirements and respective coal share (in terms of energy content) in the fuel mix for the policy no CCS case under different fuel and carbon price combinations

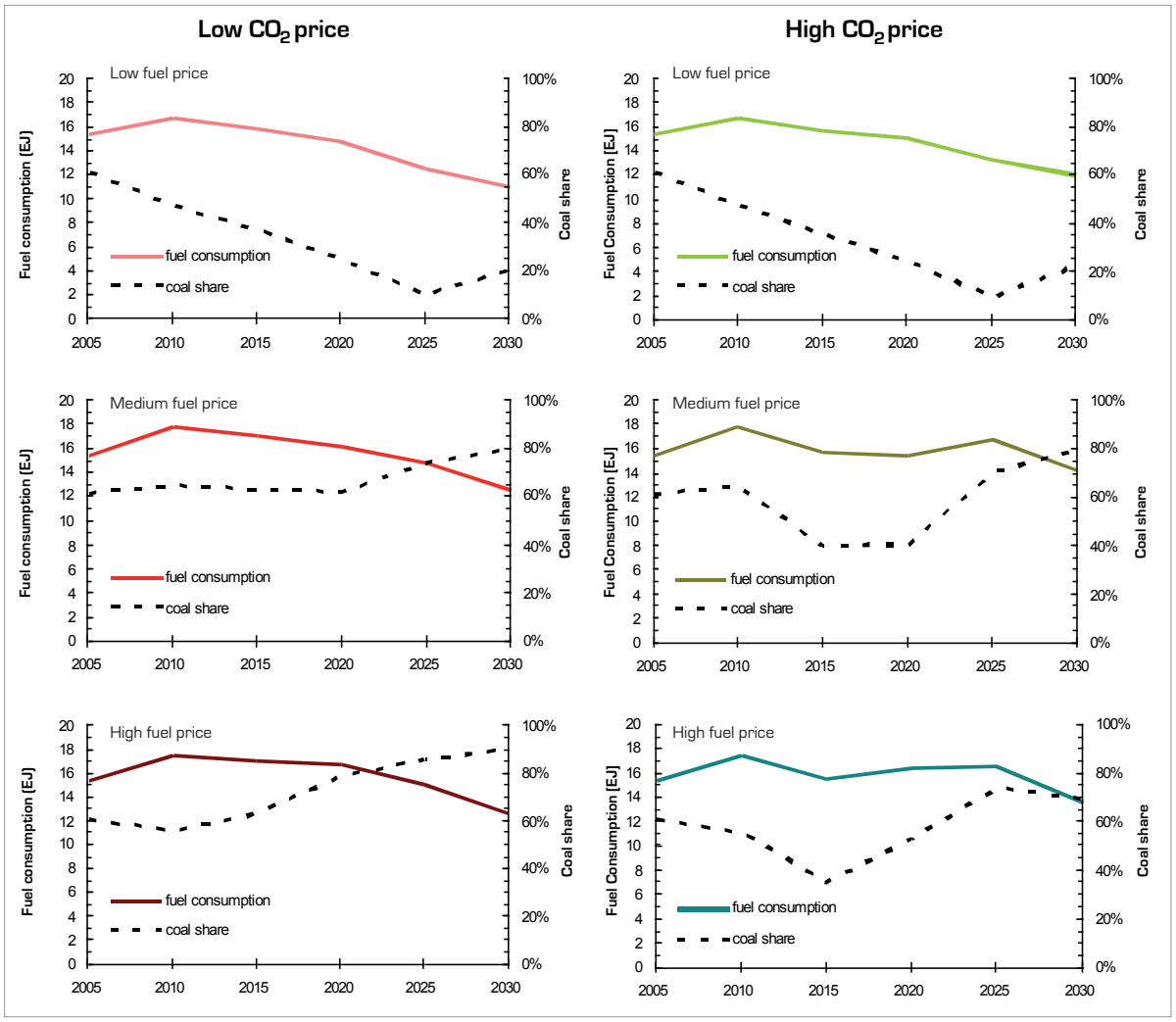

Figure 7.10: Annual fuel requirements and the respective share of coal (in terms of energy content), in the fuel mix for the policy CCS case, given different fuel and carbon price combinations

The highest cost is associated with the *high fuel - low CO_2 price scenario* that favours a high share of coal technology.

When *CCS technology is available*, the capital requirements vary between EUR 250 billion and EUR 460 billion with the expenditure for the *high CO_2 price scenarios* increasing by 40% to 75% compared to the *no CCS case*. The *low fuel - low CO_2 cost scenario* remains the one with the lowest capital costs. The highest costs result when both *fuel and CO_2 prices are high*. The total capital expenditure in the *policy case with CCS* is in the order of 70% of the capital expenditure in *the respective BAU CCS case*.

7.3 Fuel consumption, diversification and cost

7.3.1 Annual fuel consumption and coal share

Figure 7.9 shows the calculated trend of annual fossil fuel consumption for electricity generation, and the estimated share of coal in the fuel mix for the *policy no CCS case*. While there is an eventual decrease in fuel consumption by 2030 for all scenarios due to the decreasing role of fossil fuels in power generation, the fuel mix differs significantly as it follows the trend of the capacity mix analysed in Section 7.1.1.

Low CO_2 prices coupled with *medium or high fuel prices* encourage the use of coal, the share of which rises to between 80% and 90% of annual fuel consumption by 2030 (slightly lower than in the *BAU no CCS case*). Conversely, *high CO_2 prices*

or low fuel prices aid the substitution of coal by natural gas in the technology and consequently the fuel mix, so that coal contributes a maximum of 20% to the fuel consumption. In the case of *high CO_2 prices* coal is hardly present in the fuel mix by 2030. Scenarios with *medium or high fuel prices* and *low CO_2 prices*, which favour coal technology, show a decrease in fuel consumption of the order of 17% by 2030. Scenarios with high penetration of natural gas technology (e.g. *when CO_2 prices are high*) show a steeper decrease in fuel consumption of the order of 35%, with annual fuel requirements around 10 EJ by 2030.

Figure 7.10 shows annual fuel consumption in the *policy CCS case*. If *high CO_2 prices* are assumed, then CCS is the technology of choice for electricity generation and it displaces conventional NGCC technology which is the dominant technology when *CCS technology is not available*. This in turn leads to increased fuel consumption and greater reliance on coal for power generation. The share of coal in the fuel mix ranges from 20% to 90% while the annual fuel consumption could reach 14 EJ by 2030.

7.3.2 Cumulative fuel consumption

The total fuel consumption in the *policy case* ranges from 360 EJ for the scenario comprising *no CCS, low fuel prices and high CO_2 prices* to 405 EJ[21] for the scenario with *medium fuel prices, high CO_2 prices and CCS deployment* as shown in Figure 7.11. The difference in total fuel consumption between equivalent economic scenarios caused by CCS deployment is in the order of 4%, if the capture plants are mostly based on NGCC technology, rising to between 10% and 12% if the technology deployed is IGCC-CCS.

Figure 7.12 and Figure 7.13 give the fraction of coal and gas in the total fuel consumption as an absolute value and as a percentage respectively. When *fuel prices are low,* natural gas is the dominant fuel irrespective of carbon prices as CCS options for these scenarios are based on NGCC technology. On average, natural gas accounts for 67% of the energy consumption with approximately 250 EJ required over the period between 2005 and 2030 for electricity generation. A similar contribution of natural gas to the total fuel mix is

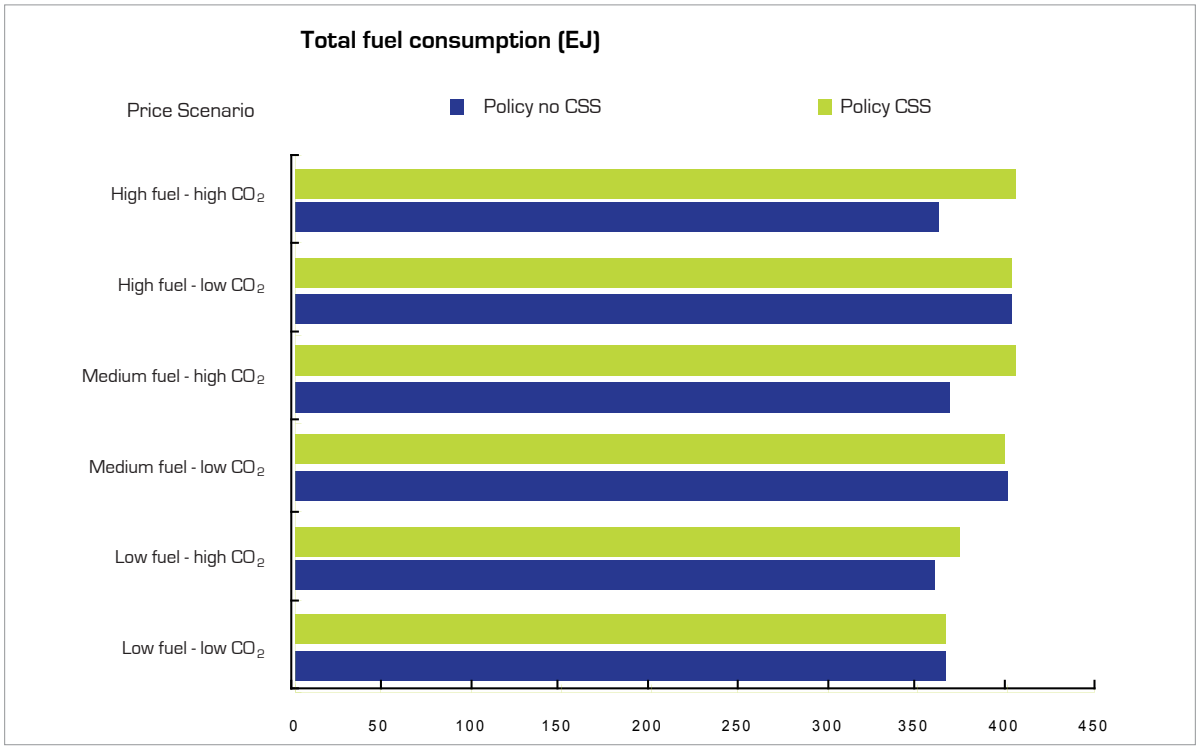

Figure 7.11: Cumulative fossil fuel consumption for electricity generation to 2030 for the policy case for different fuel and carbon price combinations

21 If annual fossil fuel consumption for power generation were to remain stable at the 2004 level (15.4 EJ), the cumulative fuel consumption to 2030 would be 385 EJ [11].

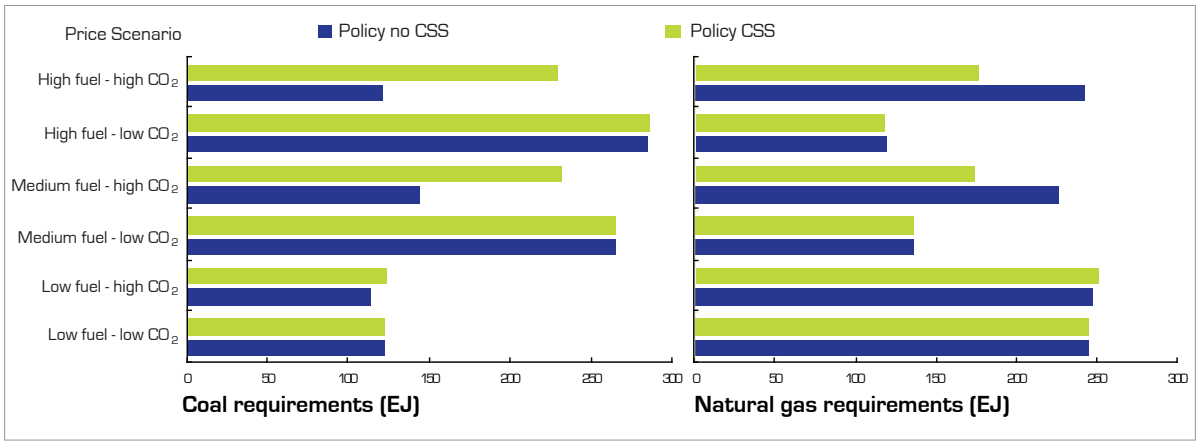

Figure 7.12: Coal and natural gas consumption for electricity generation to 2030 for the policy case for different fuel and carbon price combinations

observed for *high and medium fuel prices* when they are combined with *high CO_2 costs* and *no CCS options*. In this case, NGCC technology is the most competitive option to generate electricity and consequently the reliance on natural gas increases throughout the period from 2005 to 2030. In all other scenarios, coal remains the prevalent fuel for fossil-fuelled electricity generation with a share of 60% to 70% of the primary energy consumption.

To put these figures in perspective, it should be noted that the use of natural gas for power generation in 2004 was 4.8 EJ [11]; if natural gas consumption for power generation remained stable to 2030, the cumulative natural gas requirements from 2005 to 2030 would reach 120 EJ. This figure is doubled by 2030 for half of the scenarios examined under the policy case.

7.3.3 Fuel diversification

As discussed in Section 6.3.3, the deviation of the fuel mix from the starting point in terms of coal's share of total fuel consumption is monitored throughout the study period in order to assess the security of energy supply for fossil fuel power generation. Figure 7.14 shows a comparative plot of the projected share of coal in fossil fuel power generation for different scenarios.

The fuel mix is optimised in *the high and medium fuel price scenarios combined with either low CO_2 prices or high CO_2 prices and CCS deployment*. However, even in these cases the system may drift towards a dependence on coal by 2030 (*high fuel price, low CO_2 price)*, or it may experience brief periods of increased dependence on gas (*high* or *medium fuel price, high CO_2 price* and *CCS* during the period from 2015 to 2020).

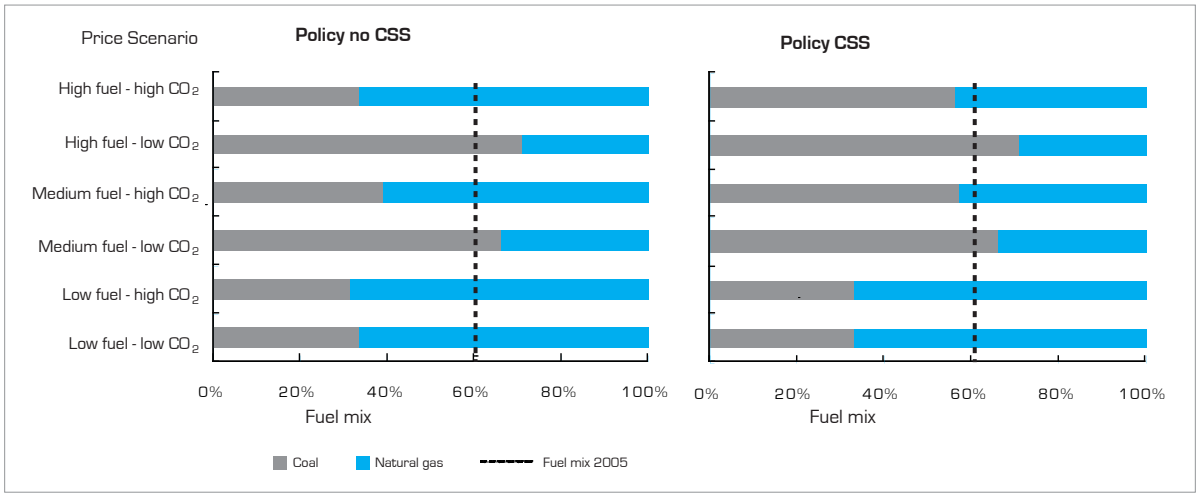

Figure 7.13: Coal and natural gas share in the cumulative fuel consumption for fossil-fuelled power generation to 2030 under the policy case for different fuel and carbon price combinations

The scenarios that reduce the dependence of the fuel mix on natural gas in the long run do not change between the *BAU* and *policy* cases. The essential difference is that while fuel consumption increases in the *BAU case*, it is on the decrease in the *policy case*, thus reducing fuel import dependence. Furthermore, while the trends in the fuel mix are similar in the *BAU* and *policy* cases, the tendency to depend on coal in the long term is not as pronounced in the policy case. This may be attributed to the fact that the steeper load duration curve in the policy case reduces the capacity of technology that operates in base load.

As discussed in Section 6.3.3, the desired share of each fuel will have to be decided according to the availability of indigenous fuel resources and the situation on the international fuel markets.

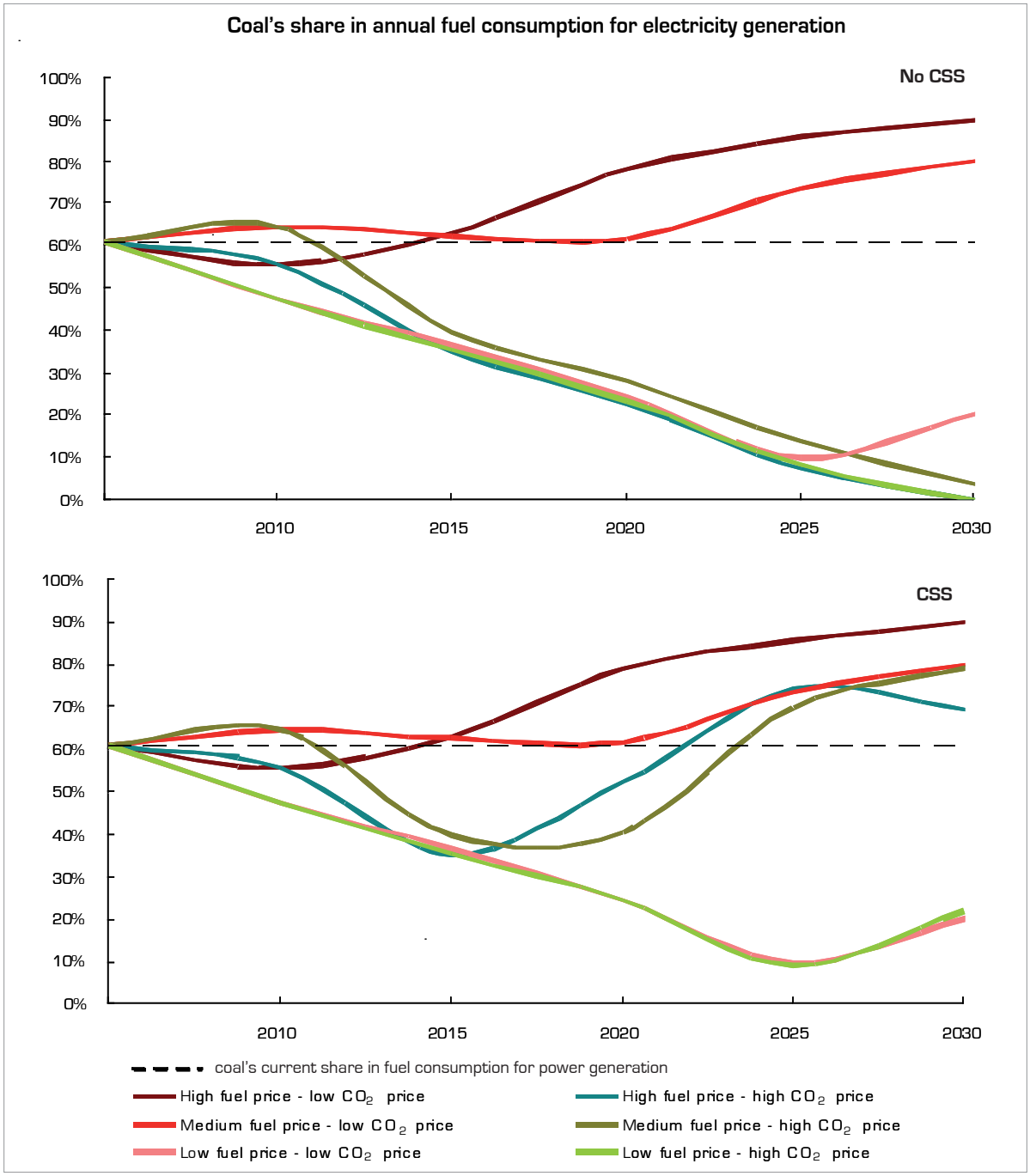

Figure 7.14: Evolution of coal's share in annual fuel consumption in the policy case for different fuel and carbon price combinations.

7.3.4 Fuel costs

The estimated fuel costs for the fossil-fuelled power generation sector in the period from 2005 to 2030 are displayed in Figure 7.15. Even though the reduction in fuel consumption presented above supports these results, the initial sudden drop in fuel costs observed in 2010 is partly artificial for reasons already explained in Section 6.3. In reality, a more gradual transition to the figures calculated for the period from 2015 to 2020 would be expected.

Annual fuel costs depend on the fuel consumption trends, the fuel mix and the fuel prices in each scenario. Figure 7.15 shows that the scenarios with the lowest fuel costs are not the ones with the lowest fuel consumption, but the scenarios where coal

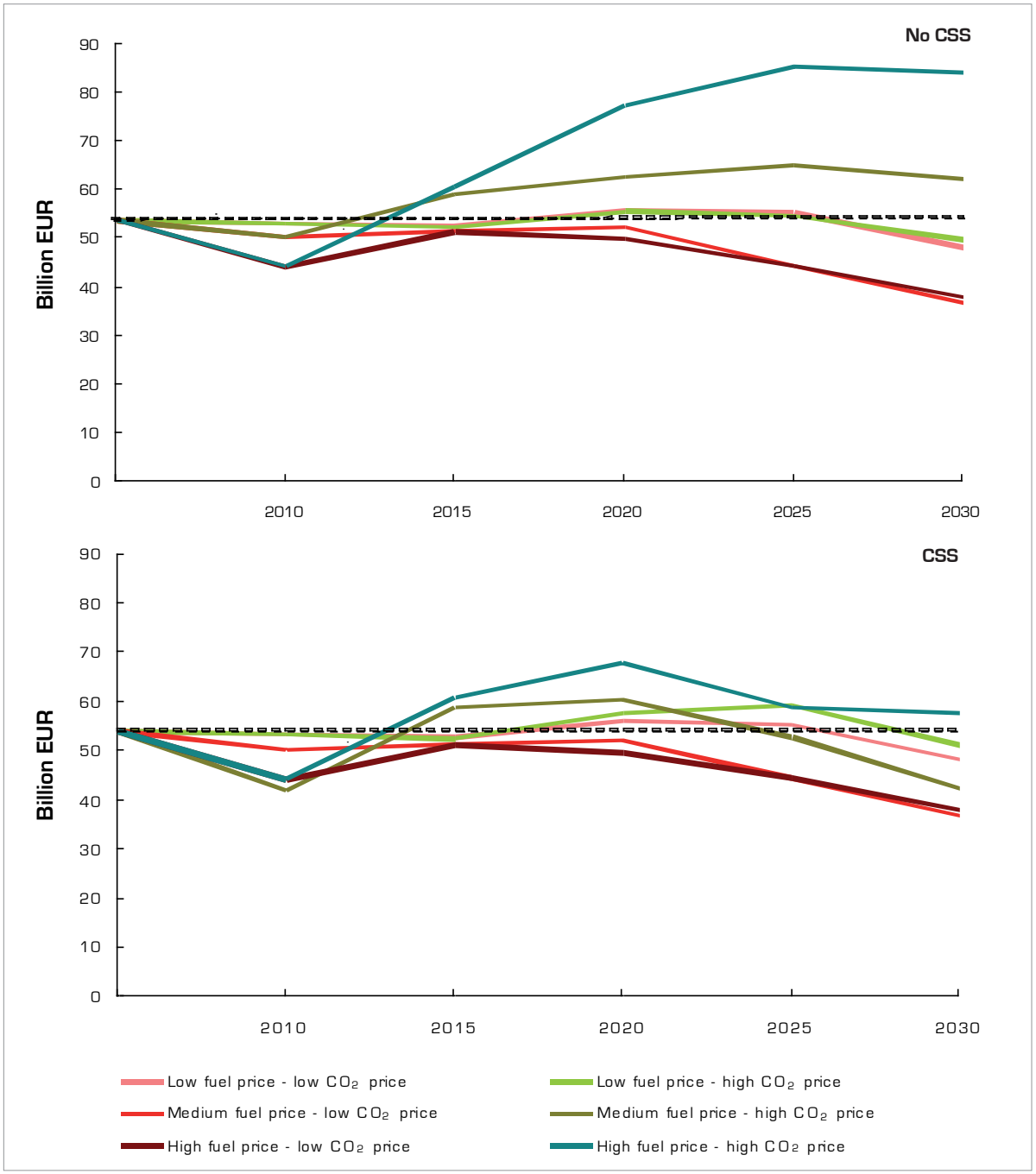

Figure 7.15: Annual fuel costs for fossil-fuelled power generation in the policy case for different fuel and carbon price combinations

has a substantial share of the fuel mix. Thus when *CCS is not available, medium and high fuel price* scenarios combined with *low carbon prices* show low fuel expenditure, dropping to EUR 40 billion per year by 2030. Conversely *high CO_2 costs* and *low fuel prices* drive fuel expenditure to high levels, reaching EUR 85 billion in 2030. The deployment of CCS has a positive effect on fuel expenditure as it shifts the fuel mix towards higher coal shares and thus reduces fuel costs.

The total fuel costs between 2005 and 2030 are displayed in Figure 7.16. The *high fuel - low CO_2 price scenario* has the lowest expenditure of approximately EUR 1 200 billion in both the *CCS* and *no CCS* case, while the *high fuel – high CO_2 price scenario with CCS* is the most expensive at EUR 1 700 billion for the period between 2005 and 2030. Given the same economic assumptions, the scenarios *with CCS* deployment incur fuel costs that are 10% to 15% lower for *high or medium fuel prices*, while in the case of *low fuel prices,* costs increase by 3%.

7.4 Carbon dioxide emissions

Figure 7.17 shows the calculated trend for the annual CO_2 emissions from fossil-fuelled power generation in the *policy case*. Except for *high or medium fuel prices combined with low CO_2 prices,* the target of reducing CO_2 emissions by 20% by 2020 is achieved in all scenarios irrespective of the availability of CCS.

If *CO_2 prices are low,* the target is only met when *fuel prices are also low*, and CO_2 emissions seem to stabilise at 53% of the reference value by 2030. While achieving the emission reduction target without increasing the price of CO_2 might appear counter-intuitive at first glance, it is easily explained by the trends observed in the technology choices for capacity expansion and replacement. Figure 7.3 and Figure 7.4 show that the combination of fuel prices in the *low fuel price scenario* drives all new capacity to be gas fired and results in a capacity mix which does not differ from the one observed for *high CO_2 prices* and consequently also achieves the emission target, albeit through a different incentive or market signal.

While it does not influence the achievement of the 20% reduction target by 2020, nor the time in which the 20% reduction can be achieved, the deployment of CCS technology does have an impact on the magnitude of the CO_2 emission reductions that can be achieved by 2030. When *carbon prices are high,* the CO_2 emissions are cut to 42% of 1990 levels by 2030 *without CCS* technology. If *CCS is deployed,* emissions drop even further.

Figure 7.18 shows the estimated total emissions from fossil-fuelled electricity generation for the

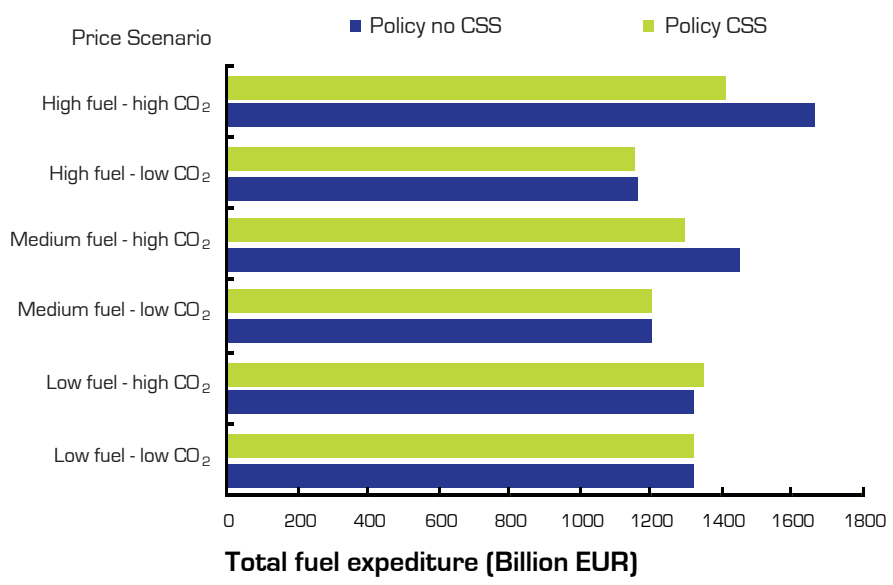

Figure 7.16: Total fuel expenditure for electricity generation to 2030 for the policy case for different fuel and carbon price combinations

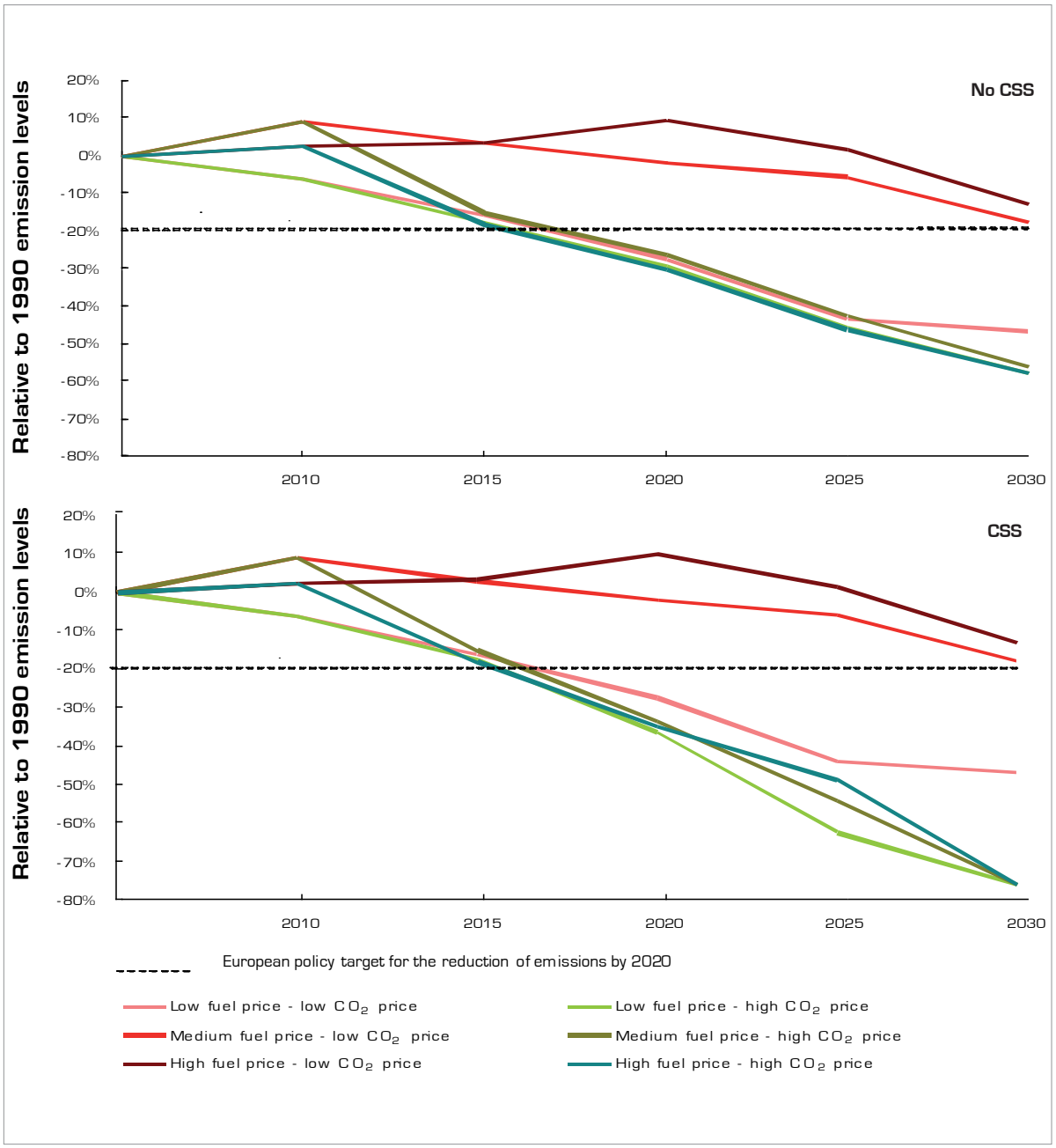

Figure 7.17: Annual emissions from the electricity generation sector compared to the 1990 emissions level in the policy case for different fuel and carbon price combination scenarios

period from 2005 to 2030. Emissions levels are at a minimum for *low fuel prices combined with high CO_2 prices*. However, the difference in total emissions is not significant between all scenarios which reach the 20% reduction target by 2020. All scenarios achieving this goal have total CO_2 emissions between 23 Gt and 27 Gt in the period from 2005 to 2030. The impact of *CCS deployment* on total CO_2 emissions is an additional 4-9% reduction depending on the scenario. The amount of CO_2 captured in the period to 2030 is 1.9 Gt, 4.4 Gt and 4.0 Gt for the low, medium and high fuel-price scenarios respectively.

For *high or medium fuel prices combined with low CO_2 prices*, the 20% reduction target is not reached and the total CO_2 emissions climb to 35 Gt.

On average, CO_2 emissions in the *policy* case are 20% lower than in the *BAU* case over the period from 2005 to 2030.

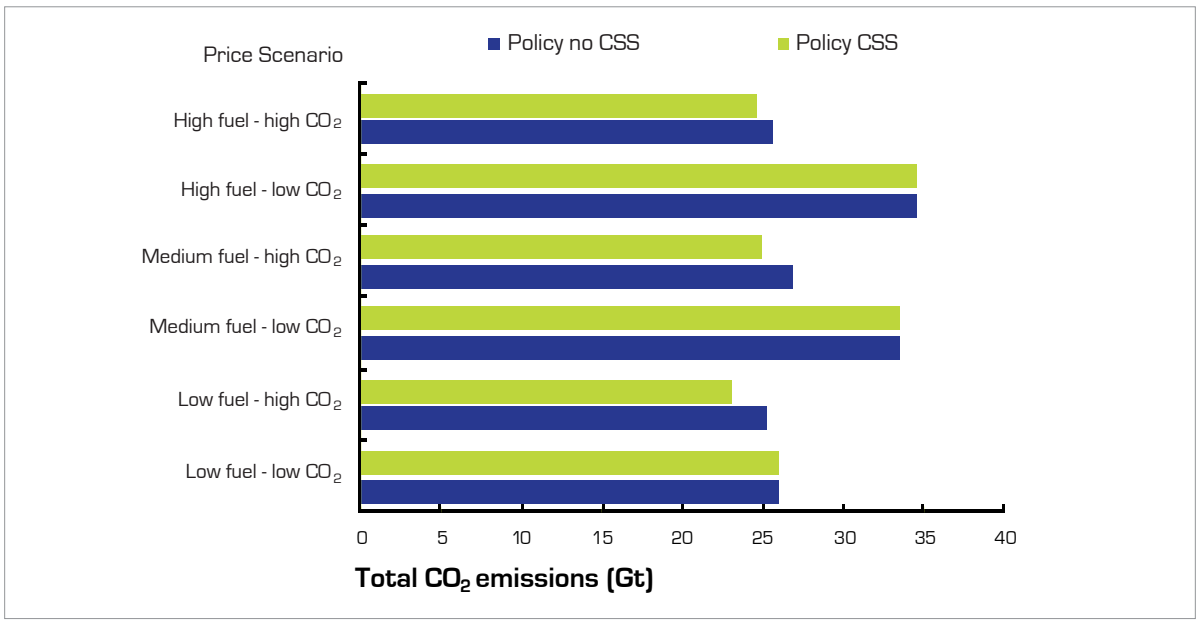

Figure 7.18: Cumulative CO2 emissions from the electricity sector during the period from 2005 to 2030, for the policy case for different fuel and carbon price combinations.

7.5 Average production cost of fossil-fuelled electricity

As shown in Figure 7.19 when *CO_2 costs are low*, electricity production costs are also low, staying below EUR 0.064/kWh for the period from 2005 to 2030. On average, *when carbon prices are low*, the costs in the *policy* case are 7% higher than in the *BAU* case.

As in the BAU case, when *CO_2 prices are high,* power production becomes more expensive irrespective of the availability of CCS technology. Electricity production costs are up to 2.5 times the starting costs estimated for 2005 by 2030. Until the period from 2020 to 2025, the increase is comparable for the *CCS* and *no CCS cases*. However, in the last period, costs rise more sharply in the *no CCS case* and end up in the range of EUR 0.087/kWh to EUR 1.08/kWh. This is between 12% and 21% higher than the respective *CCS scenarios* in 2030, where electricity production costs amount to EUR 0.077/kWh to EUR 0.090/kWh.

The difference between electricity production costs for the *BAU* and *policy* cases is smaller when *CO_2 prices are high*. Electricity production costs per kWh in 2030 are 1% to 4% higher on average in the *policy case* when compared to the respective scenarios in the *BAU case*.

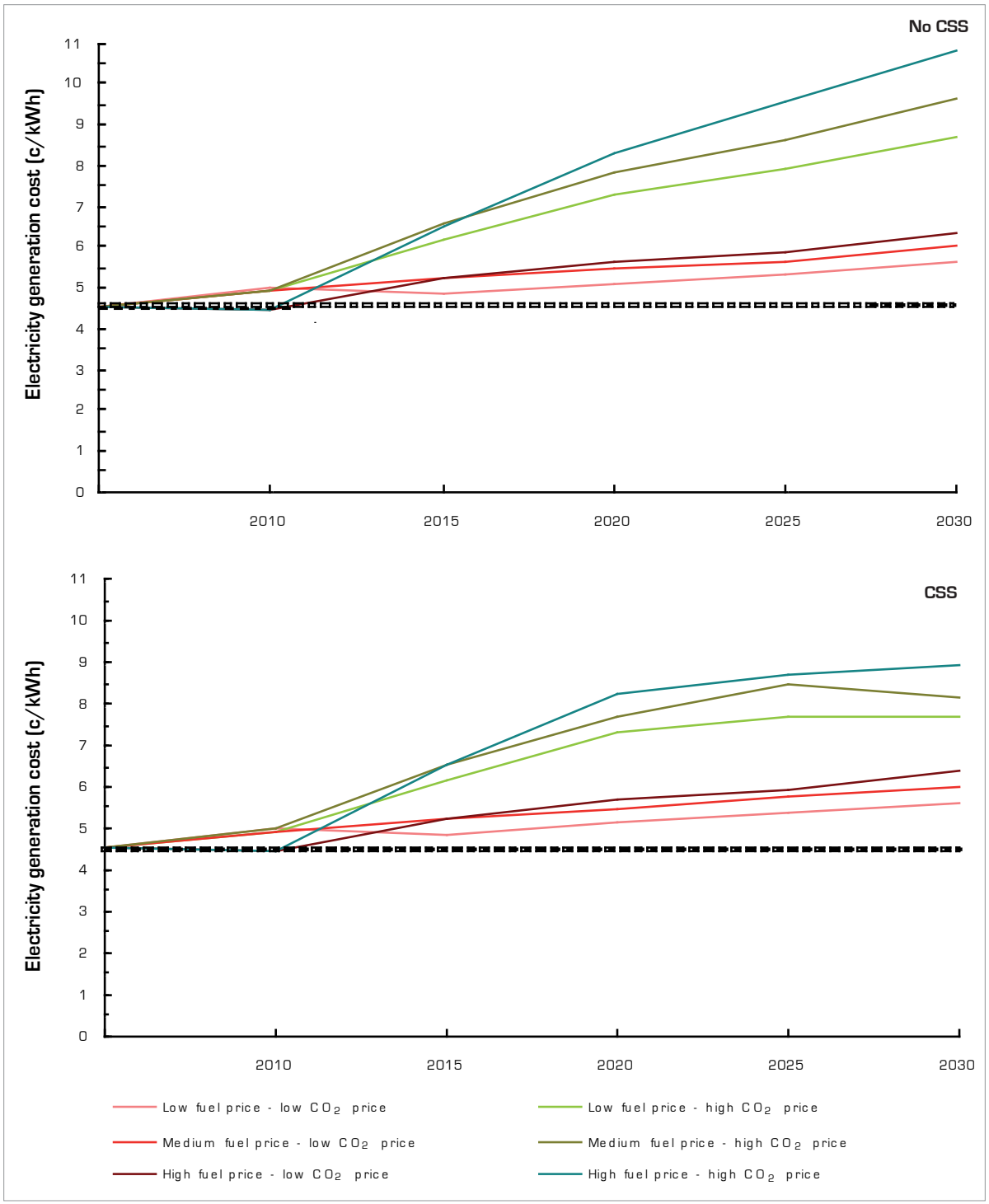

Figure 7.19: Estimated electricity production costs in the policy case for different fuel and carbon price combinations.

8 Impact Assessment

This chapter aims to assess the impact of the capacity expansion choices associated with the scenarios studied on Europe's energy policy goals, namely sustainability vis-à-vis the reduction in CO_2 emissions, security of supply and competitiveness; and to identify the conditions that could catalyse the deployment of an '*optimal*' fossil fuel power generation technology mix that could simultaneously fulfil all the objectives of the European energy policy.

This impact evaluation is performed in two steps. Initially, the scenarios that are compatible with two of the energy policy goals, sustainability and security of energy supply, are identified by comparing the values of the associated indicators calculated in the previous chapters to reference values that are linked to these objectives. Finally, the capital investment required and the resulting production costs for fossil-fuelled electricity are reviewed for the expansion choices associated with the scenarios that simultaneously fulfil the criteria for sustainability and security of energy supply.

8.1 Sustainability – Reduction of CO_2 emissions

As stated in Chapter 2, the EU has agreed to reduce the greenhouse gas emissions that it produces by 20% compared to 1990 levels by 2020. In order for this objective to be realised, CO_2 emissions from fossil-fuelled power generation will have to be reduced by at least the same fraction, if not more, to compensate for lower emission reductions from other sectors, such as transport, where the available technology and the associated economics will not favour the reduction of CO_2 emissions on a large scale within the given timeframe. Therefore, in the context of this impact assessment, a 20% reduction in CO_2 emissions from power generation in 2020 is set as the evaluation criterion for the performance of the different scenarios in terms of sustainability:

- Annual CO_2 emissions in 2020 must be at least 20% lower than emissions in 1990; the trend in emission reductions has to be maintained beyond 2020.

All scenarios that fulfil the above criterion are identified in Table 8.1. Nearly all scenarios in the policy case fulfil this criterion, with the exception of those that are associated with low carbon prices and medium/high fuel prices. In these latter cases, CO_2 emissions are higher since conventional coal power plants have a large share in the new capacity, due to the relationship between coal and natural gas prices that makes pulverised coal technology more competitive than the less carbon intensive NGCC plants beyond 2015.

On the other hand, the combination of a low CO_2 price with low fuel prices leads to a reduction in CO_2 emissions. In this case, the emissions of the power generation sector meet the aforementioned target since the NGCC technology is more competitive than pulverised coal and dominates the new capacity, due to the low price of natural gas. For low CO_2 prices, CCS technology does not influence CO_2 emissions, as the threshold price for CO_2 is not achieved and the market conditions do not allow the commercial deployment of this technology option, even when the technology is mature.

High carbon prices have a positive effect on the reduction in CO_2 emissions by steering the power plant fleet towards the adoption of CCS technology, or, if CCS technology is not available, towards less carbon intensive NGCC plants, irrespective of the relationship between the prices of coal and natural gas, since the carbon costs override fuel costs. This highlights the important role of high carbon prices in efforts to reduce CO_2 emissions.

It should also be noted that in the policy case where CO_2 prices are high, the sustainability criterion is met even without the deployment of CCS technology. Nevertheless, the deployment of CCS offers deeper cuts of the order of between 4 and 9 additional percentage points in 2030. In the BAU case however, the emissions reduction target is only achieved with the deployment of CCS technology, which necessitates both the demonstration and availability of the technology on a large scale and high carbon prices. On average, emissions in the BAU case are 20% higher than emissions in the policy case.

The study identified the conditions favourable for the introduction of CCS technology in the power plant fleet. In the case of high CO_2 prices, making CCS compulsory through regulation has no effect on CO_2 emissions, as power plants with CCS would already be the most competitive technology, taking the maximum share of the market possible after commercialisation. Under low CO_2 prices, if conventional power plant options (Pulverised Coal (PC) and Natural Gas Combined Cycle (NGCC)) are disregarded and CCS technology is enforced as the only option for large scale power generation, then the

analysis indicates that the new capacity has a large share of open cycle gas turbines. This is not a likely development, but rather an indication of the inability of the current methodology to cope with such market interventions, when the capital and operating costs of CCS technology are much higher than those of conventional large scale power plants. Rather than an increased share of open cycle gas turbines, it is likely that there will be delays in the replacement and expansion of the fleet, leading to an extension of the operating life of aged power plants and a shrinkage of the reserve margin. As a result, CCS technology is introduced to the power generation system at a slower rate and does not reach the capacity level achieved through a fully competitive market.

Figure 8.1 shows the cumulative CO_2 emissions from each scenario for the period from 2010 to 2030; these are presented relative to the lowest value for this indicator: 23 Gt of CO_2 emitted in the policy case under high carbon prices, low fuel prices and the availability of CCS technology.

In conclusion, this analysis has demonstrated the following.

- Significant additional penetration of non-fossil fuel power generation technologies (renewables and/or nuclear) is essential for reducing CO_2 emissions.
- The deployment of CCS technology could complement a greater share of non-fossil fuel power generation technologies as a measure to cut the emissions of the power generation sector. Under a BAU scenario with the penetration of renewables and nuclear, the deployment of CCS technology is essential in order to meet the defined sustainability target.
- High carbon prices are needed to reduce CO_2 emissions by forcing the power plant fleet to shift to CCS technology, or, if CCS technology is not commercialised, to less carbon intensive NGCC plants. This analysis also showed that significant emission reductions under low carbon prices can only be achieved when very low natural gas prices prevail.

8.2 Security of energy supply – Diversification of fuel mix

The security of energy supply can be addressed in terms of absolute fossil fuel consumption, which is implicitly related to fossil fuel imports, i.e. coal and natural gas; and in terms of the composition, and hence of the diversification, of the fuel mix. Increases in the efficiency of the fossil fuel power plant fleet and higher shares of renewables and nuclear power are translated into reduced fossil fuel consumption and hence into a decreased dependence on fossil fuel imports. Similarly, a reduced share of natural gas will limit the EU's external vulnerability to imported hydrocarbons.

In this context, two criteria were adopted when assessing of the impact of each scenario on the security of energy supply:

- annual fuel consumption for power generation in the period to 2030 is not increased compared to the current level;
- the contribution of coal consumption to the total fossil fuel consumption in the power sector varies between the current level of 61% and 80%[22].

Only the scenarios under the policy case fulfil the first criterion. In the BAU case, increases in the electricity demand at rates higher than those of the penetration of non-fossil fuel technologies cancel out any gains in fossil fuel consumption from the introduction of more efficient conventional power generation technologies. The situation worsens when the less efficient CCS technology is introduced. In the BAU cases, the annual fuel consumption in 2030 ranges between 9% and 56% above the 2005 levels.

On the other hand, a significant penetration of nuclear and renewables in the policy case leads to a reduction in fossil fuel consumption compared to current levels even in the case of CCS deployment. Annual fuel consumption in 2030 is between 7% and 35% below the 2005 level. Figure 8.1 shows a graphical comparison of the cumulative fuel consumption for all scenarios considered relative to the lowest calculated value: 360 EJ associated

22 The upper limit is set to avoid the overdependence of the sector on a single fuel. Both upper and lower limits are indicative. The actual values could be re-defined according to the availability of indigenous fuel resources and the situation on the international fuel markets.

with the *policy case – no CCS – low CO_2 price – low fuel price scenario* that is associated with the deployment of the most efficient natural gas combined cycle technologies.

The condition of the second criterion linked to fuel mix composition is only met by an even more limited number of scenarios. The share of coal in the fossil fuel mix varies within the predefined margin in only five scenarios, marked in Table 8.1. In these cases the share of coal-fired power plants in the new capacity is in the range of 37% to 44%. This is achieved when coal power plants are deployed only after the 2015-20 period and dominate the new capacity thereafter, while, during the period 2005-15, the majority of the new capacity is fuelled by natural gas. Figure 8.1 shows the share of coal in fuel consumption in 2030 for all scenarios.

Overall, the two criteria for the security of energy supply are met simultaneously in only four scenarios of the Policy case: (i) *low carbon price - medium fuel price – CCS*; (ii) *low carbon price - medium fuel price – no CCS* (the capacity mix in these two scenarios is identical), (iii) *high carbon price – medium fuel price – CCS*; and (iv) *high carbon price – high fuel price – CCS*.

Overall, the security of supply is maintained in the following ways.

- Increasing the share of non-fossil power generation (renewables and/or nuclear), which leads to a reduction in fossil fuel consumption.
- A combination of high CO_2 prices, medium or high fuel prices, and the commercialisation of CCS technology; or a combination of low CO_2 prices and medium fuel prices irrespective of the commercialisation of CCS technology. These conditions steer the technology mix in a way that the current contributions of coal and natural gas to the fuel mix are maintained.

8.3 Overall comparison – Associated costs

Only two scenarios simultaneously meet the criteria for sustainability and security of energy supply: (i) *policy case – high carbon price – medium fuel price – CCS*; and, (ii) *policy case – high carbon price – high fuel price – CCS*. The key conditions framing these scenarios can be summarised as follows:

- they describe an evolution of the power sector with a high penetration of non-fossil power generation (renewables and/or nuclear);
- they are associated with the development and deployment of carbon capture technologies, which necessitates high carbon prices;
- fuel prices are medium or high.

In these two scenarios, the average production cost of fossil-fuelled electricity ranges between EUR 0.082/kWh and EUR 0.090/kWh in 2030, depending on the price of fuels, which represents an increase of the order of 82% and 100% respectively compared to current average production costs. The overnight capital costs required for the build-up of the new capacity are similar for these two scenarios, around EUR 460 billion.

Table 8.1 shows the average fossil-fuelled electricity production costs in 2030 and the cumulative overnight capital expenditure figures for all scenarios in this analysis. A graphical comparison of these indicators is shown in Figure 8.1.

8.4 Concluding remarks

The optimal technology mix for the fossil-fuelled power generation sector of the future is the one that simultaneously minimises CO_2 emissions, fossil fuel consumption and the production costs of electricity, while decreasing the share of natural gas in the fuel mix. It is apparent from this analysis that specific market and technology development conditions need to be met for these goals to be achieved at the same time. As a consequence, the policy maker or regulator must develop and implement the necessary strategies to influence the factors that define the evolution of power generation capacity, ultimately steering the sector in a way that is compatible with the goals of energy and environmental policies[23].

A number of these factors have been considered in this analysis, namely the contribution of non-fossil fuel technologies (renewables and nuclear) in power generation; CO_2 prices; fuel (coal and natural gas) prices; and CCS technology. Nevertheless, not

23 A further challenge to the policy maker is how to devise the proper mechanisms to effectively change these factors as required. This is however not addressed in this report.

all of these factors can be influenced by policy. The further penetration of non-fossil fuel technologies can be stimulated by regulation and financial incentives, CO_2 prices could be influenced to some extent by regulation, and the commercialisation of CCS technology could be catalysed by research, development and deployment policies. However, coal and natural gas are commodities that are traded globally/regionally and the policy maker cannot have a major influence on their price.

The preceding analysis has revealed that under specific conditions, the evolution of the power generation sector can become compatible with the development of a sustainable energy system.

- The shares of non-fossil electricity generation need to be increased.
- Under medium or high fossil fuel prices (higher than EUR 6.5/GJ for natural gas and EUR2.3/GJ for coal in 2030), CO_2 prices need to be high (higher than EUR 34/t CO_2 to EUR 55/t CO_2 in 2020) and CCS technology needs to be developed to become commercialised.
- Under low fossil fuel prices (less than EUR 6.5/GJ for natural gas and EUR 2.3/GJ for coal in 2030), although CO_2 emissions and absolute fuel consumption are reduced, irrespective of the CO_2 price and the commercialisation of CCS technology, the power generation sector will depend almost exclusively on natural gas in 2030, hence having a detrimental effect on the security of energy supply. Hence, it appears that under low fuel prices, Europe will not be able to meet all the goals mentioned above simultaneously, relying solely on market forces and the conditions assumed in this analysis.

It should be stressed however that these conclusions are based on the assumption that all Member States in the European Union follow the market signals. In fact, national capacity expansion plans will take into consideration additional factors such as national strategies e.g. on nuclear or social policy, the availability of indigenous fossil fuel resources, renewable potential, etc.

Scenario				Sustainability	Security of supply		Competitiveness	
				Criteria		Additional information		
	CCS	Fuel price	CO_2 price	CO_2 emissions	Fuel mix	Fuel consumption	Electricity production cost	CAPEX
BAU	No	High	High			+9%	10.5	337
BAU	No	High	Low			+37%	5.9	552
BAU	No	Medium	High			+12%	9.5	351
BAU	No	Medium	Low			+36%	5.6	516
BAU	No	Low	High			+9%	8.3	325
BAU	No	Low	Low			+20%	5.2	353
BAU	Yes	High	High	✓	✓	+48%	8.6	627
BAU	Yes	High	Low			+37%	5.9	552
BAU	Yes	Medium	High			+56%	8.1	631
BAU	Yes	Medium	Low			+36%	5.6	516
BAU	Yes	Low	High	✓		+28%	7.5	471
BAU	Yes	Low	Low			+20%	5.2	353
Policy	No	High	High	✓		-35%	10.8	265
Policy	No	High	Low			-17%	6.4	401
Policy	No	Medium	High	✓		-34%	9.6	268
Policy	No	Medium	Low		✓	-18%	6.0	362
Policy	No	Low	High	✓		-35%	8.7	255
Policy	No	Low	Low	✓		-28%	5.6	246
Policy	**Yes**	**High**	**High**	✓	✓	**-11%**	**9.0**	**463**
Policy	Yes	High	Low			-17%	6.4	401
Policy	**Yes**	**Medium**	**High**	✓	✓	**-7%**	**8.2**	**456**
Policy	Yes	Medium	Low		✓	-18%	6.0	362
Policy	Yes	Low	High	✓		-22%	7.7	352
Policy	Yes	Low	Low	✓		-28%	5.6	246

Table 8.1: Overview of the performance of the 24 scenarios in terms of sustainability, competitiveness and security of supply. Fossil fuel electricity production cost is expressed in EUR/kWh and capital expenditure in billion euros. Fossil fuel consumption and fossil electricity generation cost values refer to the year 2030.

Figure 8.1: Comparative view of all scenarios, against the best performing case per category (value in red), except in the case of coal's share, where the starting point of the current level and the 80% dependency on coal limit are displayed.

9 Conclusions

- Between 510 GW and 635 GW of new fossil fuel power plant capacity will have to be constructed in the EU by 2030, to meet the increasing demand for electricity and to replace retiring power plants, depending on the penetration of renewables and nuclear power. A large fraction of the new capacity needs to be constructed in the coming decade, highlighting the urgency of the issue. The capital requirements for the construction of the new fossil fuel power plant fleet are in the range of EUR 250 to EUR 460 for the low and EUR 325 to EUR 630 billion for the high estimate of new capacity requirements, depending on the portfolio of technologies that will be deployed.

- If carbon capture technologies are not deployed, the cost of CO_2 emissions will be the decisive factor for technology selection: low carbon prices will promote the deployment of coal plants and high carbon prices natural gas combined cycle plants.

- The deployment of carbon capture technologies in 2020 necessitates a minimum CO_2 price of the order of EUR 34/t to EUR 55/t, depending on the prevailing fuel prices. If this threshold value is exceeded, power plants with carbon capture will dominate new capacity and could reach a penetration level of up to 190 GW to 280 GW; this corresponds to between 33% and 40% of the total installed capacity in 2030. Higher fuel prices will promote the deployment of coal-fired IGCC plants with pre-combustion capture, while lower fuel prices will promote natural gas combined cycle plants with post combustion capture. Under the assumptions of the study concerning the techno-economic performance of power plants, pulverised coal plants with post-combustion capture are not competitive.

- Under high carbon prices, the influence of fuel prices on the technology mix is small. Under low carbon prices, fuel prices affect the relative share of pulverised coal and natural gas plants: higher fuel prices result in higher coal capacities.

- Under business-as-usual assumptions for the penetration of nuclear and renewables, where fossil fuel technologies maintain their current share in power generation, annual CO_2 emissions from the power sector only reach a 20% reduction below 1990 levels by 2020 with the deployment of carbon capture and storage. Under a low carbon policy, where the share of renewables and nuclear in electricity generation increases from 44% in the BAU case to 70% in 2030, this target can be achieved by high CO_2 prices alone, while the deployment of carbon capture technologies offers additional reductions. Under low CO_2 prices, carbon emissions can only be significantly reduced if very low natural gas prices prevail in the period to 2030, resulting in the deployment of a power plant fleet comprising only natural gas combined cycle plants.

- A high penetration of renewables and nuclear energy will help promote security of energy supply by reducing the demand for fossil fuels and the dependence on imported natural gas. The large scale deployment of coal-fired carbon capture technology or a combination of low CO_2 prices and medium fuel prices will also reduce the use of natural gas.

- The production costs of fossil-fuelled electricity will increase in the future due to the rising costs of CO_2 and fuel. A significant outcome of the analysis is that, despite the associated higher capital costs, the deployment of carbon capture technology could keep fossil fuel electricity production costs lower in a carbon constrained environment than in cases where this technology is not deployed on a large scale.

- Under business-as-usual scenarios, the power sector cannot simultaneously meet the target for CO_2 emission reductions and promote the security of energy supply. Increased shares of non-fossil fuel electricity generation are essential for achieving the energy and environmental goals of the EU. In addition, high CO_2 prices and the demonstration and large scale deployment of coal-based carbon capture technology are needed for the development of a future European fossil fuel electricity generation capacity which is compatible with the European goal of a sustainable, secure and competitive energy system.

Acknowledgments

The authors would like to thank the following experts for reviewing the draft manuscript and making useful recommendations that were considered for the preparation of the final document:

Z. Mladen, Energy Institute Hrvoje Pozar, Croatia
A. Poullikkas, Electricity Authority of Cyprus
A. Papageorgi, Eurelectric
M. Steen, JRC
D. Baxter, JRC
H. Petric, JRC.

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European Commission

EUR 23080 EN – Joint Research Centre – Institute for Energy

Title: **Future Fossil Fuel Electricity Generation in Europe: Options and Consequences**

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Luxembourg: Office for Official Publications of the European Communities
2009 – 98 pp. – 21.0 x 29.7 cm
EUR – Scientific and Technical Research series – ISSN 1018-5593
ISBN 978-92-79-08176-7
Catalogue number LD-NA-23080-EN-C
DOI 10.2790/38744

Abstract

This study investigates the development of the fossil fuel fired power generation sector in Europe up to 2030 and identifies the critical factors that influence its evolution. Through the application of the least-cost expansion planning method, the technology and fuel mix of fossil fuel power plant portfolios emerging from twenty-four techno-economic scenarios are described. The different scenarios present alternative views for the role of non-fossil fuel (nuclear and renewable) power generation, the development of the world fuel and carbon markets and the carbon capture power generating technologies. The study estimates the needs for new fossil fuel capacity and identifies the optimal power plant mix for all possible combinations of the cases mentioned above. The impacts of the resulting portfolios on the objectives of the European energy policy are assessed using as indicators the capital investment for the construction of the required capacity, the fuel consumption, the composition of the fuel mix, the CO_2 emission levels, and the average production cost of electricity from the fossil fuelled fleet. The report finds that high CO_2 prices need to be maintained and carbon capture technology must be developed and become commercialised. If these conditions are met and medium or high fossil fuel prices prevail, the portfolio of fossil fuel power plants that will be deployed will be compatible with the European goal for the development of a more sustainable and secure energy system. The key conclusion is that for a sustainable and secure energy system we need to invest, both in the increase of non-fossil fuel power generation and to ensure that carbon capture and storage technologies are ready to be deployed when needed.

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JRC
EUROPEAN COMMISSION

LD-NA-23080-EN-C

ISBN 978-92-79-08176-7

Publications Office
Publications.europa.eu