


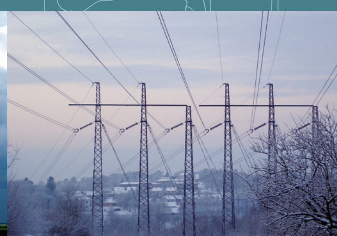

EUROPEAN ENERGY PATHWAYS

Towards a Sustainable European Electricity System

European
Energy Pathways

Towards a Sustainable European Electricity System

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Foreword

I am proud to present the second book reporting on the progress and result of the research programme “Pathways to Sustainable European Energy Systems”, covering the period 2010–2013. This research programme looks at how the European energy system can be transformed to meet reductions in CO_2 emissions, so as to comply with targets to Year 2050, such as limiting global warming to 2ºC. The first book reported on the period 2005–2009, and the current book builds on and develops the results presented in the first book. During the research period covered in this book, we focused more or less entirely on issues related to the transformation of the electricity system, whereas the first research period reported in the first book had a somewhat broader scope.

A key aspect of the research performed is the inclusion in the analysis of a detailed description of the present energy system, as this obviously will have a significant influence on the possibilities to transform the energy system over the coming decades. During this research period, we have developed and refined this description, incorporating essential information about the electricity transmission network, as well as detailed data on wind and solar resources. In addition, the modelling capabilities have been further improved and, as can be seen from the results presented, we now have a modelling toolbox that can be used to investigate in a comprehensive way how the European electricity system can be transformed to comply with the various targets for reductions in CO_2 emissions from electricity generation. A key issue on which we are focusing is the possibility for large-scale integration of variable (intermittent) electricity generation, especially wind power. During the second research period we have also increased the research effort related to demand-side issues of the electricity system, such as efficiency measures and load shifting.

The recently issued IPCC 5th assessment report on mitigation of climate change (Working Group III, 5AR) illustrates the tremendous challenges that face the global community if global warming is to be restricted to 2ºC above pre-industrial levels. To me, the report seems to confirm one of the conclusions made in our previous book, namely, that all technologies and measures are required if we are to avoid irreparable damage to ecosystems from climate change. This conclusion is even more valid now considering the work that has been performed in the meantime, and which is presented in this book. Thus, resolving the problem of the threat to the climate means that we all have to compromise, applying a broad portfolio of technologies and measures, all of which have some negative environmental effects or are disliked by a certain group or groups in society. Despite the magnitude of this challenge, Europe should be able to take the lead and show the world that many opportunities will emerge from transforming the energy system, and that a broad political consensus is possible. Unfortunately, the economic recession, as well as the current political instability in countries bordering the EU have slowed the momentum of the work. We can only hope that these issues will be sorted out and that Europe will regain its momentum towards transforming its energy system. As for the electricity system, one could say that society simply has to follow the pathways presented in this book and the climate targets will be met! While this is of course overly optimistic, I hope this book will encourage politicians and other stakeholders in their efforts to impose strong and clear policy measures for transforming the electricity system – after all, the electricity system offers many possibilities for measures that cannot be imposed in other sectors.

The work has involved some 20 researchers, who are addressing various aspects of the challenge to transform the electricity system. The following chapters summarise the results from the various activities and are divided into key areas, such as *The long-term development of the European electricity-supply system* and *Large-scale integration of renewable electricity*. Similar to the first book, the aim of this book is to provide added value to the scientific publications that have emanated from the project.

As for the previous period of the programme, the work reported in this book was presented to, and discussed with, a broad group of stakeholders in industry and in governmental organisations. These discussions have been very valuable for the work and for maintaing the focus of the activities.

I would like to thank all the researchers who have participated in the Pathways research programme and who have worked hard to make this book and the underlying scientific papers possible.

The main funding for the work presented in this book was provided by Vattenfall AB, the Swedish Energy Agency, the Chalmers-E.ON initiative, ELFORSK (through the project North European Power Perspectives), and IEA Bioenergy (Task 43). I am grateful for the tremendous work put in by my co-editors Erik Axelsson, Ulrika Claeson Colpier, and Thomas Unger. Without them chasing me there would have been nothing to co-edit.

I hope you will find the book of value and that you will enjoy reading it!

Filip Johnsson
Project leader
Göteborg, September, 2014

Content

Executive summary

Executive summary

This book presents and discusses the results obtained from comprehensive analyses of various options to reduce significantly emissions of carbon dioxide (CO_2) from the European electricity system over the coming decades. The European Commission has expressed an ambition to reduce the levels of greenhouse gas emissions (GHGs) by 80%–95% up to Year 2050. Achieving this goal will inevitably have significant impacts on all parts of the European energy markets. Moreover, the desired cuts in the levels of GHGs, especially of CO_2, must be carried out in a way that maintains the security of supply, as well ensuring social and economic sustainability. Meeting this challenge will require a thorough understanding of the associated technical, social, political, and economic issues related to the transformation of the energy system.

Given the advantages to reduce emissions in the electricity-supply system, as compared with other sectors of the energy system, emissions from the electricity sector may have to approach zero by Year 2050 if the long-term energy and climate policy goals of the EU are to be met. With this in mind, the analyses presented in this book address the features and characteristics of a future electricity system with near-zero emissions, the ways in which it will work, and the possibilities and challenges that will be encountered during the transformation towards such a system.

The Pathways research programme

The Pathways research programme has, up till now, been carried out in two separate phases, which together span the time period 2006–2013. The main objective of the research programme is to conduct a comprehensive analysis and assessment of the long-term transition of the European energy system towards a significant reduced impact on the climate in Year 2050. This development follows the roadmap towards a competitive, low-carbon economy set out by the European Commission (EC) in Year 2011. The focus of the research programme is on the electricity system, and the key topics include: the role of the existing energy infrastructure; defining and analysing scenarios (or pathways) towards Year 2050; and assessing the large-scale integration of renewable electricity. Furthermore, the research presented here considers the entire supply-demand chain of the electricity system, including, to various extent, transmission and distribution.

Important contributions from energy systems modelling

Throughout the research programme, the development of comprehensive and detailed energy system models has been an essential task for the research group. Such tools are necessary to describe in detail and analyse the complexity of the energy and electricity systems that span the entire supply-demand chain, including transmission and distribution. The different parts of the model package are linked together through "hard linking" and "soft linking", in a way that facilitates the coherent analysis of all parts of the transformation. The scope of the model package covers the EU-27, Switzerland and Norway, and the time-frame is up to Year 2050. Using the Chalmers databases on fuel resources and electricity-generation capacities as the foundation, an accurate and detailed description of the current energy system is made possible in the model package. However, it must be stressed that the aim of the modelling is not to predict the future but rather to assess the challenges and possibilities regarding fulfilment of the EU goals in different scenarios of the future development of parameters, such as fuel prices and CO_2 emission reduction targets.

Main results and conclusions

The results from the first phase of the Pathways research programme have been presented in an earlier book[1]. The present book and this executive summary primarily deal with the analyses conducted during the second phase of the Pathways research programme. Nonetheless, as some of the conclusions drawn from the first phase have been reinforced over time, we have retained and adopted these issues in the work presented in this book. Hence, in the following section, we give a brief presentation of the most important findings and reflections made during the course of the (second phase of the) Pathways research programme.

All technologies and measures are required to follow the pathways towards sustainability

It is possible to make deep cuts in carbon emissions until Year 2050, while at the same time maintaining the stability of supply. However, the assessment of the conditions for the different technologies and measures indicate that it is most likely that this will require that all available technologies and measures have to be considered as options towards Year 2050. In theory, while it is of course possible to exclude some technologies based on preferences, considering the large cuts in emissions that are needed, there is a need for compromise rather than combativeness when it comes to making technology choices.

Renewable energy is the key to transforming the energy system

Thanks to national support schemes and climate-mitigation policies, the share of renewables in the European electricity generation has increased considerably, and our model analyses emphasise that this trend must continue towards Year 2050 for the pathways that meet the goals set up by the EC. Increased reliance on renewable electricity is, of course, also beneficial from a European security-of-supply perspective. The difference between the scenarios investigated here is related to how *large* the expansion of renewables will need to become. Thus, the future share of renewable electricity will depend not only on policy, but also on the prospects for other competing CO_2-lean supply options, such as natural gas-based electricity generation, Carbon Capture and Storage (CCS), and nuclear power.

[1] Johnsson F. et al., 2011, "European Energy Pathways – Pathways to sustainable European energy systems", Department of Energy and Environment, Chalmers, ISBN:978-91-978585-1-9.

The abundance of global fossil-fuel resources presents a genuine challenge

From a climate-change perspective, there is clear evidence that fossil fuels are too readily available and abundant around the world. In this book, we lend support to this notion by showing that countries with large resources of fossil fuels have continued to expand their use of fossil fuels at a rate that surpasses their expanded use of renewables. Globally, the richest single source of fossil fuels is coal. That the world may be running out of conventional oil is not the crucial issue, as there are still substantial resources of coal, natural gas, and unconventional reservoirs of hydrocarbons, such as tar sands and oil shale. These large resources are being developed on continuous basis.

Carbon Capture and Storage is an important technology in efforts to meet the fossil fuel challenge in a global context

CCS represents a response to the threat posed by the large resources of fossil fuels, since it allows fossil fuel-rich countries to combine large cuts in emissions with uninterrupted use of their fossil fuel resources. However, the development of CCS has slowed in recent years and there are few, if any, large CCS demonstration projects in Europe or the US, i.e., the two economies that probably will have to lead the way in developing and demonstrating CCS. The development of CCS is likely to determine the extent of the impact on climate of the continued exploitation of the abundant fossil resources across the world. Moreover, our research shows that in the European context, CCS is essential for the European energy-intensive industry to take its share of the long-term climate-mitigation targets.

The EU-ETS must regain its position as the leading climate policy instrument

Currently (Year 2014), price signals in the European carbon market are too low (4–5 €/tCO_2) to stimulate directly investments in carbon-lean technologies. Nonetheless, a cap-and-trade market, in the form of the existing EU Emissions Trading System (EU ETS), is probably the most widely acceptable policy instrument for curbing GHG emissions. If carbon emissions are not priced at a sufficiently high level, it seems highly likely that the use of fossil fuel resources will continue even if the use of renewables is increased through, for example, renewable energy policies. Although renewable policies are important policies for the security of supply and efficiency of the economy, these should be balanced with a stronger climate policy to meet the Year 2050 targets. The scenario analyses described in this book assume that an effective cap-and-trade scheme is in place until Year 2050 to meet the EU climate policy goals. Our research indicates that ETS prices may need to exceed 100 €/tCO_2 by Year 2050 to achieve the required emission reductions.

Significant potential for low-cost and short-term emission reductions

There exists a significant, albeit unexploited, potential to reduce the levels of CO_2 emissions from the European electricity supply in the short-term perspective. The model-based calculations reveal that CO_2 emissions are reduced by approximately 20% in the electricity sector (or about 5% of the total emissions in the EU) if the EU Emissions Allowance (EUA) price of the EU ETS approaches 40 €/tCO_2. This potential for reduction of CO_2 emissions is technically feasible in the very short-term perspective, since an increase in the EUA price influences the dispatch of the existing electricity-generating capacity (short-term operation of power plants), whereby efficient gas-fired power plants increase their running times and coal-fired power plants reduce their outputs accordingly. However, given the present oversupply of EUAs, this type of price development appears to be unlikely up to Year 2020. Furthermore, the short-term potential for reduction of CO_2 emissions identified here may be jeopardised in the longer term by the currently low level of utilisation of existing, efficient, gas-fired power plants, possibly leading to the permanent closure of these plants.

Natural gas may offer a bridge towards meeting long-term climate policy goals

If fuel and CO_2 prices act to favour natural gas (over primarily coal), the potential to reduce CO_2 emissions in Europe will be significant, not only in the short-term perspective as mentioned above, but also in a longer time-frame and including new investments in electricity generation based on natural gas. In one of the model calculations, in which we assume a relatively low gas price to coal price ratio (i.e., 2), natural gas consumption in the European power sector increases, with the major increase occurring in the period 2020–2030. Such a development would alleviate the requirement for early deployment of CCS. The resulting increase in gas consumption should not be critical with respect to supply, although it would probably lead to an increased dependency of the EU on imports, which would raise concerns about the security of supply. Therefore, natural gas may offer a bridge towards an almost-zero-carbon-emitting electricity system, also in a medium-term perspective.

The existing energy infrastructure will strongly influence the pathways towards Year 2050

An important element to consider regarding the transformation of the energy system is that there is already a system in place, i.e., the present energy infrastructure with installed capacities in place and with associated actors and institutional framework. This comprises a large capital stock with a long turnover time. The databases compiled during our work and the modelling show that existing technologies and fossil fuels will continue to play decisive roles for at least 20–30 years into the future. However, there is a need for substantial investments in new generation capacity while the current plants are phased out, either because they have reached the end of their assumed technical life-time or are incurring too high a cost for e.g. emitting CO_2. Furthermore, there are legal and social structures, as well as valuable know-how associated with the currently dominant technologies. All these factors will act to preserve the existing system and business models.

Both existing and new energy infrastructures must be developed

Large investments will have to be made towards strengthening, expanding, and upgrading the electricity networks and other infrastructures to accommodate increased levels of wind power and other forms of intermittent electricity generation. Furthermore, a tighter and more flexible linkage between the supply and demand of electricity is likely to require considerable investments in infrastructure related to new technologies and possibilities, such as those provided by advances in information technology. The possible implementation of CCS and the increased use of bioenergy will require an extensive transport infrastructure in the form of a CO_2 transportation and storage infrastructure and biomass handling facilities.

Policy-instrument design is crucial for allocating compliance cost in the electricity market

The increasing costs for CO_2 reduction will increase electricity prices. However, the evolution of electricity prices, in both the wholesale and retail markets, is significantly affected by the ways in which policy instruments are designed and introduced. Generous support for renewable electricity tends to exert downward pressure on the wholesale electricity price, everything else being equal. At the same time, if electricity consumers (rather than taxpayers) are required to fund that support, electricity retail prices may end up at very high levels, as in the case of e.g. Germany for households, commercial enterprises, and smaller industries. In contrast, if policy-making focuses entirely on reducing CO_2 emissions, with the consequence that a significant carbon cost emerges, both wholesale and retail electricity prices will be subject to upward pressures.

There is significant potential for onshore wind power in Europe

Based on a detailed GIS-modelling approach, we estimate the realistic potential for onshore wind power in the EU to be approximately 2000–3000 TWh per annum, i.e., 50%–80% of existing gross demand for electricity in the EU. Within this estimate, we have considered possible conflicts with alternative use of land, such as may occur in areas that are densely populated and areas that are subject to environmental protection. Lakes, rivers, and transportation roads are also taken into account in the final estimate. Around half of the identified potential is estimated to be available for exploitation at an overall cost of less than 100 €/MWh. Continued technological developments that reduce specific investment costs or increase the utilisation factor of wind turbines may increase the share of the potential for onshore wind power that is available at relatively low cost. According to our model analyses, not all of the above-mentioned wind power potential of 2000–3000 TWh will be needed, even if the EU meets its long-term climate policy targets towards Year 2050.

There are several possibilities to compensate for variable electricity generation

Increased shares of variable renewable electricity generation will imply a number of additional challenges being presented to the electricity system. In many aspects, these challenges originate from the natural variability of electricity production from renewable electricity generation, such as from wind and solar power. However, there are several options for accommodating variable electricity generation in the electricity system, for instance:

- Altering the dispatch of thermal power plants, e.g., increasing the utilisation of more flexible and smaller power plants.
- Increasing the flexibility of thermal power plants through investments.
- Considering a geographical allocation of renewable electricity generation installations, so as to dampen variations.
- Improving the transmission and distribution systems.
- Curtailing (i.e., reducing) the production levels of wind and solar power installations, so as to adapt to variations in demand.
- Introducing demand-side management, including load-shifting measures.
- Introducing storage at the supply side, e.g., using fly wheels and pumped hydropower, and at the demand side, e.g., using batteries and active and smart charging strategies for electric vehicles.

These measures are generally associated with additional costs, so-called *system integration costs*. Such costs are generally difficult to fully assess but need to be considered in the assessment of large-scale integration of (variable) renewable electricity generation.

The global potential of biomass for energy supply is difficult to estimate and, therefore, uncertain

A closer look at the different estimates of global biomass resources that have been reported in other studies reveals large variability in the estimates of the supply potentials and availabilities of different bioenergy-resource categories (e.g., 100–1600 EJ by Year 2050). The spread of values may be explained by the fact that many of the determining factors are inherently uncertain, e.g., how society formulates sustainability requirements and policies, and the different regulations as to how land can be used. Biomass from dedicated plantations is generally regarded in the literature as the largest – but also the most uncertain – resource. The size of this resource depends on many factors, not least the demand for animal food products and the land claims associated with meat and dairy production. While many studies commonly adopt food-first principles and introduce restrictions to estimate so-called “sustainable” levels of bioenergy supply, no level of biomass supply comes with a guarantee of sustainability.

Proper governance of bioenergy is needed to ensure sustainable use of this renewable resource

Biomass governance (through legislation, best management guidelines or trade standards) is essential, since the deployment of bioenergy involves dealing with a range of environmental, social and economic objectives, which are not always fully compatible with each other. While the emerging bioenergy governance presents many challenges, it is important for ensuring that the rapidly expanding bioenergy industry confers benefits and that the negative effects are avoided or mitigated. As an example, it is presently a matter of some debate as to whether bioenergy from existing forests contributes to climate policy objectives; the discrepant views are partly due to disagreements regarding the assessment methodology and as to whether assessments should consider long-term or short-term effects. A strategy directed towards a more harmonised global approach is considered to be the best option for the governance of bioenergy.

The role of the demand side is essential

Meeting the climate and energy policy targets of the EU will inevitable have impacts on the demand side. The potential for energy savings on the demand side is known to be large. The challenge lies in creating the policy instruments needed to release a substantial share of that potential. As far as the European building sector is concerned, our research indicates that the final energy demands of that sector could be reduced by approximately 50% (corresponding to the technical potential). Since the European building stock accounts for almost 40% of the total final energy consumption in the EU, the impact of the entire energy supply would be substantial. Furthermore, the demand side may play an important role in the successful integration of large-scale variable renewable electricity generation, such as wind and solar power. To handle the variations in electricity generation, the benefits of being able to control the demand, e.g., by shifting loads in time, become apparent. We have also found that increasing the flexibility of electricity demand, so-called demand response, can improve the economic outcome of small-scale decentralised electricity production, such as photovoltaic (PV) cells.

This Executive summary spans a selection of the most important findings reported in the present book. The following chapters provide more comprehensive descriptions of the results and how they were achieved.

Introduction

Introduction

Background

Over the last century, the demand for commercial energy services, such as electricity, heat, and transport, has increased dramatically in Europe and around the world. Currently, more than 80% of all commercial energy that is used globally is sourced from fossil fuel reservoirs. Given this heavy reliance on fossil fuels, and the associated release of CO_2 and other greenhouse gases (GHGs), the global community now faces serious environmental and technological challenges.

To address and mitigate the increasingly serious threat of climate change, the global society must urgently face the challenge of substantially reducing the levels of GHG emissions, especially those of CO_2. Policy-makers must develop near-term strategies to set both the European and global economies on a course towards energy sustainability. Technologies already exist or will soon become available, which if implemented on a sufficiently large scale would make it possible to make the cuts in CO_2 emissions that are required to maintain global warming at less than 2ºC. This is the level identified by the IPCC as being necessary to avoid catastrophic effects on ecosystems. However, reducing CO_2 emissions (as well as the emissions of other GHGs) must be carried out in a way that maintains the security of supply and guarantees social and economic sustainability. The European Union (EU) has proposed ambitious energy and climate policy goals to meet the criteria for a sustainable energy future. By Year 2020, GHG emissions are to be reduced by 20% relative to the emission levels in Year 1990. Furthermore, by Year 2020, the share of renewable energy should be 20% of total gross consumption, and the use of primary energy should be reduced by 20% relative to a baseline projection by Year 2020. The target for the reduction of GHG emissions has been transformed into a common European cap-and-trade scheme, the EU Emissions Trading Scheme (EU ETS), as well as separate national targets for the non-tradable sectors, which include transportation, buildings, the commercial sector, and parts of the industrial sector. In addition, the renewable energy target has largely been converted into national legislation across the Member States. A framework for the Year 2030 policy was proposed in January 2014 and is subject to ongoing discussions and analyses. Both the European Parliament and the European Commission have proposed a GHG emissions reduction target of 40%, as compared with the level in Year 1990. With respect to the targets set for renewable energy and increases in efficiency or reductions in energy use, the viewpoints of the Commission and Parliament currently diverge (see more in the chapter *Setting the scene*). Looking further into the future, towards Year 2050, the Commission's ambitions and policy goals are defined in the EU Energy and Climate Roadmap 2050, which was launched prior to the Year 2030 framework (in Year 2011) and has been used as guidance for the Year 2030 framework. Subsequently, GHG emissions in the EU are to be reduced domestically by at least 80% by Year 2050 (relative to the corresponding levels of emissions in Year 1990).

Model analyses initiated by the European Commission to assess the impacts of the targets expressed in the EU Energy and Climate Roadmap 2050 indicate that with respect to reducing CO_2 emissions, the European electricity supply system has certain advantages over other sectors, such as industry. Consequently, emissions that emanate from the electricity supply system in the EU may have to approach zero-level to meet the above-mentioned target of 80% reduction in GHG emissions for the entire energy system. Large-scale integration of renewable electricity generation is obviously a key option for reaching emissions targets. However, such integration poses new challenges and imposes requirements on other generation technologies in the supply system, on the transmission and distribution grids, and also on the end-users, to uphold the balance and interactions between supply and demand.

The Pathways research programme

This book reports on research carried out within the Pathways research programme, which is designed to elucidate how one can transform the European energy system, with the focus on the electricity system. To date, the Pathways research programme has comprised two separate phases. From the *first phase* of the research programme (period 2006–2010), it was concluded that in order for Europe to meet emission reductions that comply with a global warming target of 2°C, all technologies and measures are likely to be required, especially if the security of supply and economic competitiveness are to be maintained. Although extensive changes to the energy system are required to follow the pathways towards a more sustainable European energy system by Year 2050, in general, the applicable technologies and measures are already available. Thus, the major challenge for transformation of the energy system is a political one, even though significant technological developments are certainly needed. Large-scale introduction of renewable technologies, especially wind power and biomass and their corresponding support systems, were concluded to be of great importance. The first phase of the program also identified the prime importance of the existing electricity-generation capacity stock. Whereas aging and, consequently, the phasing-out of power plants will require massive investments over the coming years, a substantial part of the existing capacity is likely to be still available post-2030. Thus, the existing capacity will have an impact on the electricity system for years to come and set the limits for, and present possibilities for, the transformation of the system towards a more sustainable form. Given the long-lasting nature of the existing system, it is of importance to find technical solutions that can exploit this system without creating lock-in effects. It was also shown that there are great opportunities for integrated solutions, such as the co-production of heat, electricity, and transportation fuels, as well as electrification of the transport sector. Furthermore, the first phase also established the concept of "bridging technologies", which primarily relate to existing or mature technologies that significantly reduce GHG emissions and that are largely associated with the existing energy infrastructure. These technologies are an important part of the transformation of the energy systems towards new and emerging technologies that have negligible impacts on climate change. Bridging technologies typically include high-efficiency, fossil fuel-powered electricity generation systems, such as combined heat and power schemes and natural gas combined cycles, biomass/coal co-combustion, and energy savings in the existing building stock and industry. Furthermore, the first phase revealed the great potential and opportunities for Carbon Capture and Storage (CCS) across several Member States of the EU. If used on a large-scale basis, CCS might enable both climate mitigation and continued use of fossil fuels. It seems reasonable to argue that Europe and the US have a leading role to play in demonstrating that CCS is a viable CO_2 emissions-mitigation option. This is the case because current hopes of preventing or dissuading different countries or zones, especially the growing economies of China and India, from continuing to use their abundant domestic resources of fossil fuels seem overly optimistic. The economic incentives to continue to exploit these resources will probably be too great for the foreseeable future. Therefore, developed economies, such as the EU, must take the lead in demonstrating the value of CCS if there is to be any expectation that fossil-rich developing economies will reduce their CO_2 emissions from the burning of fossil fuels.

In the *second phase* of the Pathways research programme (period 2010–2013), which is the topic of this book, the research questions that were addressed in the first phase have been further refined and the analyses deepened in relation to the European electricity system. Many of the conclusions from the first phase still hold true and define the framework for the second phase. However, the development of renewable electricity generation has occurred more rapidly than anticipated in different parts of Europe, e.g., in Germany. As a result, the choice between what to include and to exclude in the concept of “bridging technologies”, as established in the first phase, is not as clear as it was some years ago. Advances that were once considered as future and emerging technologies, such as photovoltaic cells (PV), are today relatively well-established in some parts of the European electricity markets. In addition, public attitudes and political ambitions are more positive towards renewables than was previously the case, even if not all the new installations for renewable electricity generation have been accepted enthusiastically by local groups. Several Member States have invested heavily in policy instruments that promote renewable electricity generation, yielding rather rapid results, with the share of renewable electricity to meet gross electricity demand increasing from around 13% in Year 2000 to >20% in Year 2012 in the EU as a whole. The potential for continued expansion of renewable electricity is also large. In contrast, the prospects for CCS in Europe are currently substantially less bright in the wake of developments in recent years. Undoubtedly, there are significant challenges associated with the technical and economic opportunities for the establishment of a CCS infrastructure. Moreover, it has become increasingly clear that a sceptical attitude towards CCS exists among the public. Looking back over the last few years, the possibilities for transformation of the energy system are better than expected for some technologies, while the challenges have proved to be much larger than expected for some of the proposed measures. These recent trends in the energy and electricity markets are reflected in the research questions addressed in the second phase of the Pathways research programme. Furthermore, more comprehensive analyses of the demand side and the resource base, including both fossil fuels and renewables, characterise the second phase of the research programme. Expanded scenario analysis, which is based on the original scenario formulation in the first phase, is also a key component of the research. Thus, in order to reflect the uncertainties and options related to policies and technologies, four main scenarios are introduced and used to investigate different possibilities for transformation of the European electricity system towards Year 2050. The scenarios each include different aspects of European policy setting, such as whether or not the climate policy target will be supplemented with targets for renewable and energy efficiency, and whether policy is implemented on a European level or on a national level. Each of these four main scenarios illustrates different pathways for the European electricity sector towards a more sustainable system in Year 2050.

The present book primarily summarises the results from the research conducted in the second phase of the Pathways research programme. As such, it represents a follow-up of the previous book[1], which reported on the outcomes of the first phase of the research programme.

Objectives

The overall objectives of the research presented in this book are: 1) to characterise and visualise the pathways to a sustainable European electricity system; and 2) to evaluate the impacts of these pathways for the characteristics of the electricity system in terms of types of technologies and technical and economic barriers.

The research that is presented in this book focuses on the following key topics:

- ***Assessing resources for electricity generation in Europe***
  Objective: To provide thorough descriptions of the European energy system, global markets for fuels, and the potentials of renewable energy resources, to be used as the basis for energy systems modelling and market analyses for energy and fuels.

- ***Analysing the long-term development of the European electricity system: Pathways analyses***
  Objective: To analyse pathways that reflect policy choices and technological developments in the supply and demand sectors of the European electricity system

- ***Assessing large-scale integration of renewable electricity across Europe***
  Objective: To investigate the opportunities and challenges for different renewable electricity generation technologies, as well as their interactions with and impacts on other parts of the energy system.

[1] Johnsson F. et al., 2011, "European Energy Pathways – Pathways to sustainable European energy systems", Department of Energy and Environment, Chalmers, ISBN:978-91-978585-1-9.

- ***To assess the options for increased demand-side efficiency and flexibility***
  Objective: To analyse and assess various options presented to end-users (mainly of electricity), so as to contribute efficiently to the different energy and climate-policy goals.

Each of these key topics is handled in separate main sections in the present book.

In addition, and in relation to the above key research objectives, the work also has a ***methodological objective***, i.e., to develop new methods and models and to adapt already existing tools, so as to resolve the research problems. The overarching objective of the methodology development is to provide a well-balanced and powerful modelling toolbox, which can be used to elucidate the pathways for the European stationary energy system from now until Year 2050. These tools can also be used to assess key parts of the electricity system (generation, distribution, and demand-side management).

Finally, the work has an ***educational objective***, involving as it does students at the doctoral and Master's degree levels, thereby providing the industrial and academic sectors in Sweden and Europe with people who have strong expertise in the energy field.

Scope

The main focus of the research presented in this book is to analyse possible transformations and development paths for the electricity system in Europe up to Year 2050. Although the main focus is on the electricity generation system, this system cannot be treated in isolation. Thus, developments and conditions in other systems and sectors must also be taken into consideration. In this work, specific efforts have been made to assess developments in the European residential sector, as the interrelationship between demand and supply will take on greater importance as the energy system is transformed. The demand side may facilitate the accommodation of intermittent electricity generation, for instance by having in the system more active end-users. Furthermore, an assessment of the options to reduce CO_2 emissions in some key industry sectors has also been included in the work.

An important consideration when transforming the energy system is that there is already a system in place – the present energy infrastructure. This energy infrastructure has components that typically have long life-times (i.e., the turnover time for the capital stock is long), which means that once investments have been made in a power plant, a transmission network or a natural gas pipeline it will be considered costly to shorten the expected life-time. Typically, power plants and other energy conversion systems have a technical life-time of about 25 years, although often the life-time extends up to 40 years. The grid infrastructure and buildings are likely to exist for even longer. Therefore, when transforming the energy system it is important to consider the limitations and possibilities inherent to the existing infrastructure. The prospects of introducing new technologies and measures are largely dependent upon how well such technologies will fit into the existing energy system, at least in a short-to-mid-term perspective. Although there will be strong development of (entirely) new and more "sustainable" technologies (e.g., new solar PV technologies and technologies that use hydrogen produced from renewables), the technologies that will account for the major share of the emission cuts up to Year 2050 are likely to be those that are already more or less available commercially. Thus, for the time-frame up to Year 2050 described in this book, it is likely that society will to a large extent have to rely on so-called 'bridging technologies' as mentioned earlier in this text. Such technologies are commercially available (or close to being commercially available) and fit into the existing energy infrastructure. To determine how the capital stock of these technologies will fit with the existing energy infrastructure, the study presented in this book applies a bottom-up methodology that includes detailed databases, which describe the current energy infrastructure with respect to power plants, transmission networks, CO_2 storage sites, and wind-power sites.

Outline of the book

This book is divided into six main sections in addition to this introductory section. Each section describes a given theme and consists of several chapters.

The first main section, titled *Setting the Scene*, presents the research framework by discussing the important boundary conditions that define and motivate the research conducted. We present EU energy and climate targets and policies, as well as current trends related to electricity generation and demand, and briefly discuss some of the challenges that lie ahead. These challenges include the transformation of both the supply and use of energy in response to the climate policy goals analysed in this book. The challenges are also associated with the introduction of a number of key technologies, which include wind power, solar power, nuclear power, and CCS, which are currently the subjects of much debate across the European Union. *Setting the scene* is followed by four results sections, each of which presents selected results and insights from research related to the given theme. The separate chapters in the results sections summarise research conducted with the aim of providing in-depth knowledge to address the overall research objectives mentioned above. In the *Resources* section, the physical limitations, challenges, and opportunities associated with energy resources are discussed. This includes an assessment of the potentials of fossil fuels and renewable fuels, as well as the possibilities to transport and store captured CO_2 emissions. These assessments not only provide the inputs to the scenario analyses, which are carried out with the aid of energy-systems modelling, but also estimate and validate the prospects for different mitigation options and technologies. The third main section, titled *The long-term development of the European electricity-supply system*, presents the modelling results from the scenario analyses of the development of the European electricity system, whereby the effects and consequences of different policies and technological developments are assessed both in the shorter- and longer-term perspectives. This includes the possible choice between a single over-arching climate goal and several goals that relate to, besides climate, decreased energy use and increased use of renewables. Furthermore, the impact of the now-decided German nuclear phase-out is part of the scenario analysis. Assessing the future role of renewable electricity in more detail and understanding the implications of integrating variable renewable electricity generation, such as wind and solar power, are important objectives of the research presented in this book. The topics are the focus of the fourth main section, titled *Large-scale integration of renewable electricity.* Here, the emphasis is on the large-scale integration of wind power and its impact on the existing system, although other technologies are also addressed. A key consideration is the intermittent nature of wind generation and the implications that this has for the existing electricity generation system. In addition, we discuss future market designs in a system with large shares of intermittent power. The inclusion of high levels of renewable (intermittent) electricity, as well as the implementation of more stringent energy and climate policies stipulate new constraints and provide new opportunities for the end-user. In this context, the fifth main section, titled *The demand-side perspective*, gives the end-user perspective and considers potential energy conservation measures for the existing European building stock, as well as the implications of demand response. Finally, the *Methods* section describes the main models and methods developed and applied to respond to the formulated research questions.

Setting the scene

- background, European energy and climate policies and challenges ahead

This main section describes the background that has motivated the research that is reported in this book. We describe and discuss the EU energy and climate policies, which constitute and define the largest share of the research presented here. Special attention is being paid to the EU Emissions Trading System (EU ETS). We also reflect upon some of the numerous challenges that we face in achieving our ambitions to transform our energy systems to having a significantly higher level of sustainability, including the controversies and uncertainties related to some key technologies, such as nuclear power and CCS. We also briefly report on current trends and discuss some of the prospects and challenges associated with the expansion of renewable electricity. We predict that the coming decade or two will entail dramatic changes in the European electricity supply, regardless of the policies that are implemented. The reason for this is simply that around two-thirds of the existing thermal power plant capacity is more than 20 years old. Thus, age-induced decommissioning of such plants is inevitable. On the other hand, a significant share of the existing capacity is likely to remain available for operation also beyond 2030. Thus, existing capacity will continue to have substantial impact in the European electricity system also in a very long-term perspective.

Setting the scene

EU Energy and climate policy

EU energy and climate policy is mainly defined and discussed in the context of three goals: reducing GHG emissions; increasing the share of renewable energy sources (RES); and reducing energy use or increasing energy efficiency. These goals are expressed with different degrees of precision and strength depending on, for example, the time-frame in question. To fulfil these goals, numerous policy instruments have been launched, both on the European and national levels. The current EU energy and climate policy is framed around three milestone years: 2020, 2030, and 2050.

The 2020 energy and climate package

The targets for the Year 2020 energy and climate package were set by EU leaders in March 2007 and enacted in Year 2009 (EC, 2009a; EC, 2009b and EC, 2009c). The package includes a set of binding legislation that is aimed at reducing GHG emissions by 20% by Year 2020 based on emission levels in Year 1990, and increasing the level of RES to 20% of final energy. Even though it is not directly included in the Year 2020 package, a third goal to reduce primary energy consumption or, alternatively, to increase energy efficiency, is also considered in the overall policy package for Year 2020 (EC, 2012). The energy efficiency goal is expressed as a target: to reduce gross energy consumption by 20% relative to a baseline projection for Year 2020, which originates from a PRIMES model run from Year 2007 (EC, 2007).[1] Unlike the emissions reduction and renewable targets, the efficiency target is not translated into binding legislation. Thus, rather than introducing binding targets at the national level, it stipulates ”binding measures”, such as an obligation to renovate public buildings and other initiatives. We will elaborate further on the three different policy objectives in the forthcoming sections.

The 2030 framework

Following the Green Paper on a Year 2030 framework for energy and climate policies (EC, 2013a), both the European Parliament and the European Commission presented in early 2014 their views and positions on the next step in European climate and energy policy: the goals for Year 2030. The Parliament voted in February for a binding of 40% reduction in GHG emissions by Year 2030 (European Parliament, 2014). Furthermore, renewable

[1] The PRIMES model is a modelling system that simulates a market equilibrium solution for energy supply and demand. The model has been developed by the Energy-Economy-Environment modeling laboratory of National Technical University of Athens and is frequently used by the EC and other European stakeholders to perform long-term analyses of the European energy system towards 2050 (E3Mlab 2011).

energy shall, according to the proposal of the Parliament, supply 30% of total final energy use by Year 2030 through the enactment of binding targets. An ambition to reduce energy use by 40% by Year 2030 was also expressed. Prior to the vote of the Parliament, the Commission presented its new energy and climate package for Year 2030 in January 22, 2014, which featured somewhat less ambition than the version proposed by the Parliament (EC, 2014a). Although the Commission and Parliament share the view on GHG emissions reductions, the Commission proposes a target for RES of 27% by Year 2030. The RES target is proposed to be binding on the EU level but not on the Member States' levels. No specification was made concerning a possible efficiency target pending the new progress review of the Year 2020 efficiency target, which is due in June 2014 (Euractive, 2014a). The vote of the European Parliament itself is not legally binding, and an agreement will need to be reached between the Commission, Parliament, and Member States (the Council) before a final proposal can be signed on, later this year (Euractive, 2014b).

Thus, at the time of writing, there are some divisions of opinion across the EU regarding the ambitions and lay-out of the climate and energy policy post-2020 and whether policy should be concentrated mainly around one overarching climate goal or that the "three-goal" policy should prevail post-2020. Ministers from eight Member States, including Germany, France, and Italy, have recently emphasised the importance of also having specific energy goals, i.e., binding renewable targets by Year 2030 (Euractive, 2014c). In contrast, spokespersons from the UK and the Czech Republic have previously favoured a single GHG reductions target.

The Roadmap 2050

In 2011, the European Commission presented its final version of the roadmap towards a competitive low-carbon economy in Year 2050 (EC, 2011a). In this roadmap, the leaders of the EU express the long-term goal of reducing GHG emissions by at least 80% (based on emissions in Year 1990) within the EU, and by up to 95% if measures outside the EU are included in the reduction budget (e.g., emissions trading with regions outside the EU). The roadmap intends to meet the responsibility taken on by the EU to fulfil the target of limiting global warming to less 2^{o}C, as compared to pre-industrial temperature levels. Hence, this goal is based on international climate research such as presented by the IPCC. The EC Roadmap indicates how the key sectors, e.g., electricity supply, industry, buildings, and transportation, can contribute in cost-efficient ways to the transition to a low-carbon economy. The analyses, which are based on PRIMES model runs, identify milestones for a cost-efficient pathway towards Year 2050 (EC, 2011b). One such milestone is the reduction of GHG emissions by 40% by Year 2030. Thus, this is the rationale for the succeeding Year 2030 framework discussed above. Furthermore, assessments of the impact of Roadmap 2050 underline the fact that the electricity supply is likely to take on a significant role in reduction efforts, approximately 95%–99% reduction in emissions from electricity supply based on corresponding emissions in Year 1990 (EC, 2011a). The reason for this is that most of the reduction measures are likely to be cheaper to implement in the electricity-supply sector than in many of the other sectors. Nevertheless, all the sectors must make substantial contributions if the overall target of at least 80% reduction in GHG emissions is to be met. Furthermore, the electricity-supply sector is not subject to the direct risk of carbon leakage, as is the case for industry owing to global competition. This is an additional argument for allowing the electricity-supply system to take on a larger share of the required cuts in GHG emissions. However, increasing wholesale electricity prices, which is an expected outcome from decarbonisation of the power sector, will also affect end-consumers, such as industries.

Current status and projections of the GHG reduction target

In the previous sections, we briefly presented the three major milestones (Years 2020, 2030, and 2050) and the corresponding energy and climate policy goals for the EU. Figure 1 shows these goals for GHG emission reductions, together with the actual developments since Year 1990 and the projected emissions taken from the Member States' own reported emission trajectories or projections. We conclude that emissions have steadily decreased since Year 1990 to the present day. However, we must not forget that the global recession, which started in late 2008 and from which we still are recovering, has had a significant impact on the decreasing trend. Summing the projections provided by the Member States indicates that the GHG targets for Year 2020 will be met or even surpassed by 1 to 4 percentage points. Most of the Member States' reports also include projections up to Year 2030. If these projections are summed, they indicate a significant halt in emission reductions between Year 2020 and Year 2030. According to these projections, the reductions would amount to 22% by Year 2030 assuming current policy instruments, and 28% by Year 2030 if one includes also planned measures. These values are significantly lower than the 40% envisaged in the Year 2030 framework. In the figure, we have also included the latest reference projection by the European Commission up to Year 2050, which was presented in December 2013 (EC, 2013b). According to this projection, emissions are estimated as being somewhat lower, with a 32% reduction by Year 2030, than the sum of the Member States' projections, which forecast emissions reductions of 22%–28% (see Figure 1). By Year 2050, the same reference case yields a reduction in GHG emissions of 44%, based on the levels in Year 1990. This projected reduction is very different from the Year 2050 ambition of at least 80%. Thus, it seems likely that policy measures will need to be stringently enforced if the goals are to be met. The information reported in Figure 1 underlines the enormous challenges that lie ahead up to Year 2030: the same reduction commitment (20%) that we have achieved in 30 years (between 1990 and 2020) is to be achieved in a single decade (2020–2030), so as to reach the mid-term goal of 40% reduction in GHG emissions.

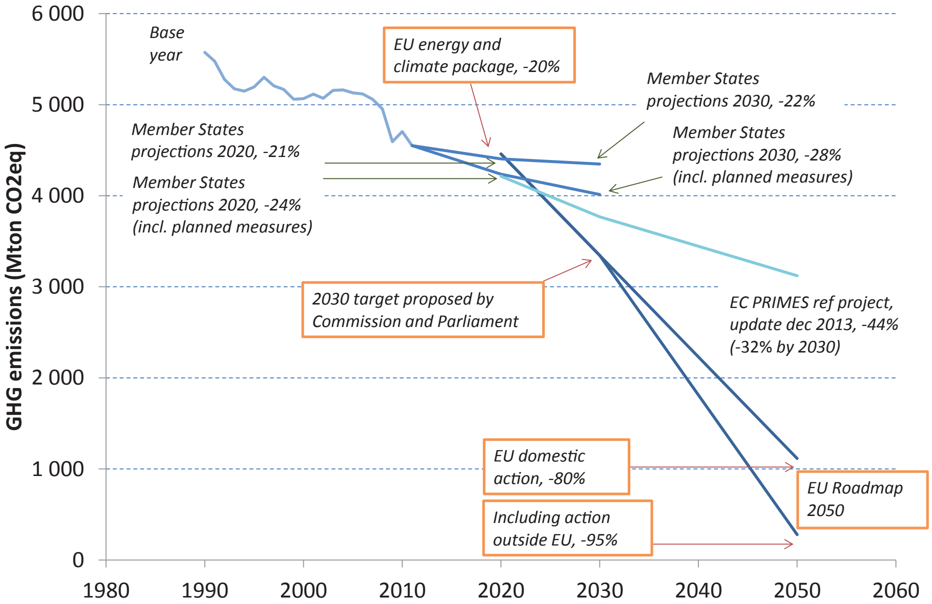

Figure 1. *GHG trends, projections, and targets for the EU-27, as given by EU common and national frameworks. Sources: European Energy Agency (2013) and EC (2013b).*

The EU ETS – a key instrument to reduce GHG emissions

Two of the cornerstones of the EU policy package that addresses climate mitigation are the EU Emissions Trading System (EU ETS) and a set of separate and national binding targets for the non-trading sector, which includes buildings, the service sector, transportation, and certain types of industries. The EU ETS is a cap-and-trade scheme that aims to reduce emissions of different GHGs from mainly combustion installations covering electricity and district-heating supply and heavy industry, by 21% by Year 2020, based on the levels of emissions in Year 2005 (EC, 2003). This corresponds to an annual linear reduction factor of 1.74%. In the Year 2030 framework, the Commission has proposed that the EU ETS shall be designed to reduce emissions by 43%, corresponding to an annual linear reduction factor of 2.2% post-2020. The EU ETS was introduced in Year 2005 and is regulated by Directive 2003/87/EC. Since its introduction, the system has been extended to include more GHGs and additional sectors, such as aviation and other energy-intensive industries. The EU ETS covers approximately 45% of the total GHG emissions of the EU and includes approximately 11 000 installations from the power and manufacturing industry sectors.

The latter of the two cornerstones, the national targets for the non-trading sector, is defined in the effort-sharing decision (EC, 2009b), which lists emissions reductions of 10% collectively in the EU by Year 2020, based on the levels of emissions in Year 2005. The binding targets differ widely among the Member States due to differences in economic wealth.

Recent development in the EU ETS market

The almost continuous decline in the EU emission allowance (EUA) price since Year 2008 is usually attributed to the economic recession (see for example EC, 2014d). This has led to reduced demand for emission allowances and, consequently, to a downward pressure being exerted on EUA prices. However, a recent study argues that the significant increase in renewable energy over the past few years has had an even greater impact on emission reductions than the economic recession (CDC Climat Recherche, 2013). The increased supply of renewable capacity, e.g., for electricity and heat supply, which has been subsidised through various renewable policy instruments, has further reduced the demand for emission allowances on the EU ETS market. This confirms the often strong relationships between different policy measures, which are observed also in the present work (see Chapter 10).

In Figure 2, the historical development of the EUA price is shown starting from the introduction of the EU ETS in Year 2005 (upper panel). The dramatic fall in price in Year 2007 was the result of an oversupply of emission allowances during the first trading period of 2005–2007, which could not be used in the second trading period of 2008–2012. Since 2008, EUA prices have decreased continuously, as discussed above. Forward prices on the market indicate persistently low prices until Year 2020, generally at levels <10 €/tCO_2. In Figure 2 (lower panel), the historical price development is supplemented with projections taken from the Roadmap modelling (EC, 2011c) and from IEA's World Energy Outlook (2012). The Roadmap scenarios differ from each other, mainly in terms of technological developments and technology options. In these scenarios, the EUA price exceeds 100 €/tCO_2 by Year 2050, and in some scenarios, it goes higher than 200 €/tCO_2. In the reference scenarios, both in the IEA WEO and the Roadmap modelling, EUA prices increase significantly from current prices and levels to around 50 €/tCO_2 post-2030. In these scenarios, the EU climate policy targets for Year 2050 are not met. Nevertheless, the levels of emissions are reduced, typically by around 40% compared to the levels in Year 1990. Thus, the model analyses indicate a considerable gap between the existing EUA price level and the projected price levels assuming that long-term policy targets are met.

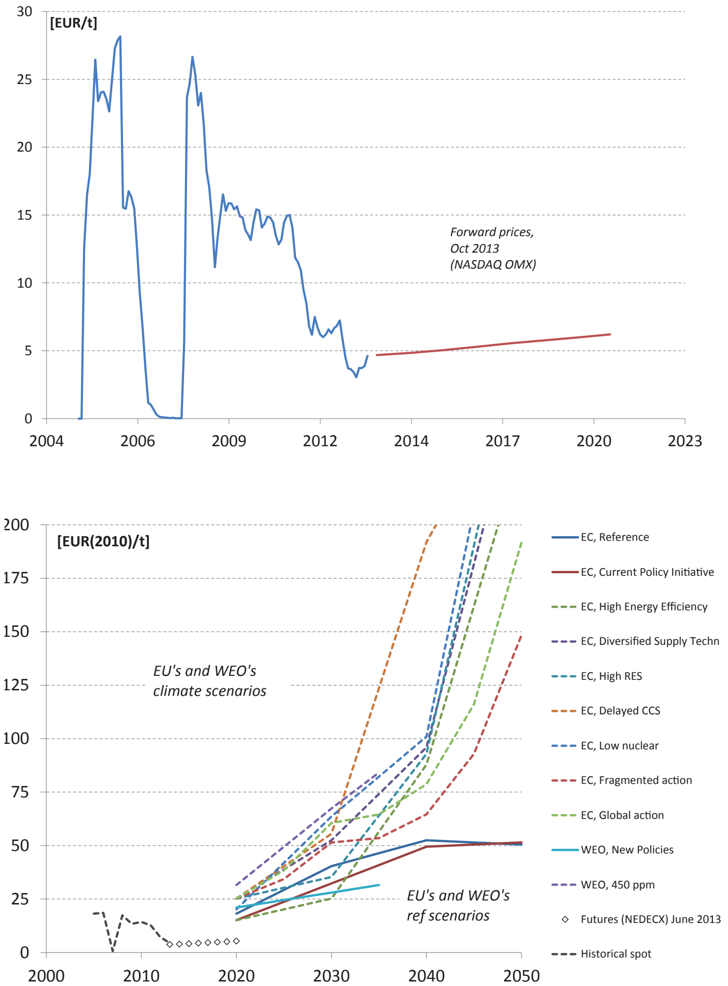

Figure 2. *Historical and futures prices of EUA (top) and projected EUA prices in the EU Roadmap study and WEO 2012 (bottom). Sources: NASDAQ OMX, EC 2011 and WEO 2012.*

Existing imbalance in the ETS market

The ETS market is currently characterised by a structural imbalance between the supply of and demand for allowances, resulting in a surplus of around 2 billion allowances that are not needed for compliance (EC, 2014b). The allowance surplus increased dramatically at the start of phase 3 of the EU ETS, which runs from Year 2013 to Year 2020, with a doubling of the surplus occurring in Year 2013, as compared with Year 2012. This development was a consequence of different factors (EC, 2014c), which included:

- record use of international credits;
- auctioning of Phase 2 (2008–2012) allowances and the remaining allowances in the new entrant reserve;
- early auctioning of Phase 3 allowances; and
- sales of Phase 3 allowances to generate funds for the NER300 programme[2].

In the absence of new measures, this imbalance in supply and demand of emissions allowances is projected to continue for the next 10–15 years and is likely to keep EUA prices at low levels (c.f. Figure 3). This is obviously problematic in terms of investment incentives for CO_2-lean technology. Accordingly, one of the conclusions from the research in this book is the importance of a strong and long-term policy measure which makes it increasingly costly to emit GHGs, especially CO_2.

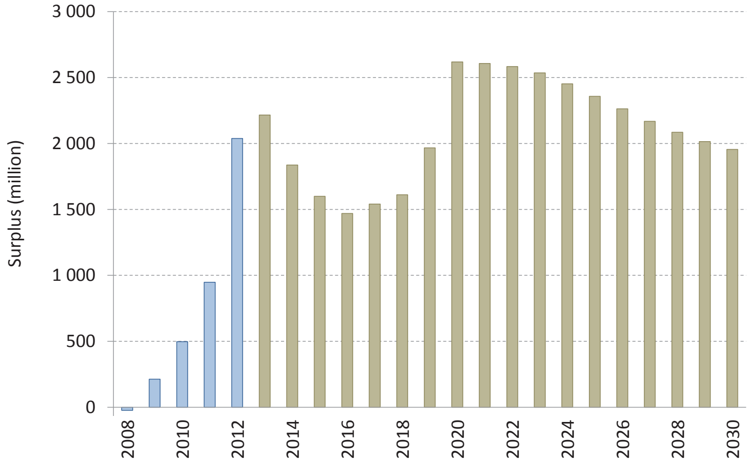

Figure 3. *Accumulated surplus of emissions allowances. The blue columns are based on actual values, whereas the green columns are estimated values. Source: EC (2014b).*

As a short-term measure to tackle the imbalance of supply and demand, the European Commission is postponing the auctioning of 900 million allowances (so-called "back-loading"). According to the latest draft amendment of the EU ETS Auctioning Regulation on back-loading, which was endorsed by the EU Climate Change Committee on January 8, 2014, the reductions in allowances will be 400 million in Year 2014, 300 million in Year 2015, and 200 million in Year 2016. Thereafter, the increases in the numbers of allowances, i.e., the re-entry of emissions allowances, will be 300 million in Year 2019 and 600 million

[2] "NER300" is a financing instrument managed jointly by the European Commission, European Investment Bank and Member States for subsidising installations of innovative renewable energy technology and carbon capture and storage (CCS), see www.ner300.com

in Year 2020. The amendment has to be scrutinised by the Council and the European Parliament's Environment Committee by the end of March 2014 to achieve the planned back-loading volumes (EC, 2014g).

The energy-analysis company Point Carbon projects that the situation with low ETS prices will persist until Year 2020, and that the impact on prices of back-loading 900 Mt of emission allowances will be limited. Back-loading will not alter the fact that the annual supply-demand balance will be positive until Year 2020, typically 300 Mt annually, so a continuous downward pressure on EUA prices can be expected (Point Carbon, 2013).

As mentioned, an important part of the Commission's Year 2030 framework is the target of achieving by Year 2030 a 40% reduction in EU GHG emissions relative to the levels in Year 1990. To reach the target in an efficient manner, the Commission estimates that ETS emissions would need to be reduced by around 43% from the Year 2005 levels (EC, 2014e). For this purpose, the Commission proposes an increase in the linear reduction factor to 2.2% per year from Year 2021 (compared with the current 1.74%; see also previous section). The Commission regards the increase in the linear reduction factor as one of the actions or measures needed to address the imbalance in the EU ETS market (EC, 2014c).

The market stability reserve

As back-loading is only a temporary measure, additional initiatives are required to handle what is currently perceived as imbalances in the EU ETS market. Such initiatives more or less relate to structural changes to the EU ETS. An example of such a measure is the aforementioned increase in the linear reduction factor of the EU ETS. Another example is the introduction of a market stability reserve for the EU ETS; its establishment at the beginning of the next trading period (in Year 2021) has been proposed by the European Commission. Thus, allowances will be placed in the stability reserve if the total number of allowances in circulation exceeds a specified level and, conversely, allowances will be taken from the reserve if the total number of allowances in circulation goes below a specified level. The total number of allowances in circulation is a liquidity indicator of the allowances in the market that are not needed for compliance. This determines whether allowances are placed in the reserve or taken from the reserve, thereby maintaining a certain level of price stability in the ETS market. The principles underlying the market stability reserve and its impacts on the market have been described recently by the EC (2014b)

The next step (as of January 22, 2014) is that the Council, the European Parliament, the Committee of the Regions, and the Economic and Social Committee take the Commission's legislative proposal for further consideration under the standard legislative procedure.

Reducing the cap on emissions – Model findings

Modelling results obtained during the research presented in this book indicate that the present targets for renewable electricity by Year 2020 are likely to keep EUA prices at very low levels until Year 2020 (discussed in detail in Chapter 10). An important explanation for this is the RES target, which constantly increases the share of renewable energy. The low "price" of CO_2 is shown in Figure 4. In this figure, marginal CO_2-abatment costs (a proxy for "price") in the European electricity system are very low until Year 2020, given that the reduction in emissions of the European electricity system corresponds to 30% by Year 2020 (relative to the levels of emissions in 1990).[3] This is the estimated contribution of the electricity supply system given the overall EU reduction target of 20% reduction by Year 2020. If emissions were instead cut by 40% in the electricity-generation sector by Year 2020, marginal costs would increase significantly to typically 20–25 €/tCO_2. In approximate terms, 40% in the electricity sector is the result of an effort of 30% in the entire energy system, which is a figure that has been mentioned earlier (the EU expressed an ambition of 30% reduction by Year 2020 if the rest of the world would take part in a combined effort; however, such a development has not taken place). These calculations are based on the assumptions that: 1) the European share of renewable electricity reaches around 35% of gross electricity demand by Year 2020 (in Year 2010, this share was almost 25%), following the Member States' national renewable allocation plans (NREAPs); and 2) total electricity demand in Europe grows at approximately 0.5% annually between 2010 and 2020 (assumptions are according to the main scenario 'Climate Market'; described in detail in Chapter 10). Assuming a lower growth in demand would entail lower marginal costs for reductions in CO_2 emissions, everything else being held constant.

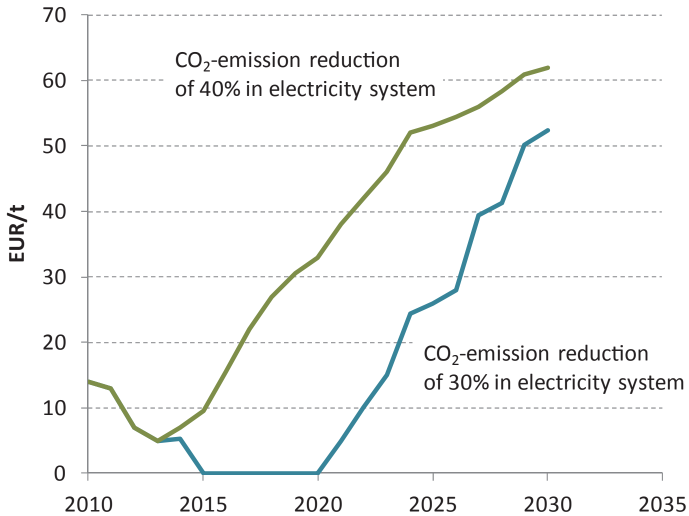

Figure 4. *ELIN model result showing extremely low marginal costs of CO_2 reduction until Year 2020 given a 30% reduction in emissions from European electricity generation by Year 2020, compared to baseline Year 1990, and prices that are typically 20–25 €/tCO_2 if emissions are reduced by 40% instead.*

[3] The results are taken from the ELIN model and from one of the main scenarios looked at in the research presented in this book. The model results and the scenarios are presented in more detail in the "The long-term development of the European electricity-supply system" section of this book.

The price development in the EU ETS or alternatively, the marginal costs of reducing GHG, such as CO_2, and the difference in outcome between an overarching climate-policy target and three climate- and energy-policy targets are important topics in the research results presented in the *"The long-term development of the European electricity-supply system"* main section of this book.

The recent shift from gas to coal in the EU – an effect of low EUA prices?

Since EUA prices have been low in recent years, the use of coal as a fuel for electricity generation has proven more profitable than the use of natural gas. However, this does not fully explain why the use of coal in the EU has increased while the use of natural gas has decreased since Year 2010 (see Figure 5). In the US, the cheap exploitation of unconventional gas, especially shale gas, during the past few years has led to a situation where the use of gas is more profitable than the use of coal in many sectors, including electricity generation. Therefore, the switch from coal to gas in the US has created an oversupply of coal on the global market, which has influenced coal prices in Europe. In Figure 6, the price development patterns for steam coal and natural gas are presented. It is clear that the price of coal has dipped twice since Year 2008. The first dip came as a result of the global recession in Year 2009, which reduced worldwide the demand for coal, and the second dip resulted from an abundant and cheap global coal supply, partly caused by the unconventional gas exploitation in the US. In the case of gas (and crude oil), only one such dip is clearly evident. Futures prices for coal and gas (in late Autumn 2013) reveal different trajectories for the two fuels: increasing coal prices and decreasing gas prices. Thus, gas may strengthen its competitiveness towards coal, especially when one considers that EUA prices are also expected to increase, albeit at a slow rate. Long-term price projections estimated by the IEA (2013) are also included in Figure 6. The higher price trajectories assume business-as-usual with increased global demand for coal and gas, while the lower price developments assume global climate-mitigation policies with reduced demand for fossil fuels and, thus, decreases in the prices of fossil fuels.

The interplay between gas and coal prices and the price on the EU ETS market and the corresponding impacts on European electricity generation are important topics in this book. These issues will be dealt with in more detail in the succeeding chapters (see e.g. Chapters 12 and 14). Moreover, the global abundance of fossil fuels and its implications for energy use and global CO_2 emissions is the subject of Chapter 1, while a special analysis of the global natural gas markets is the topic of Chapter 2.

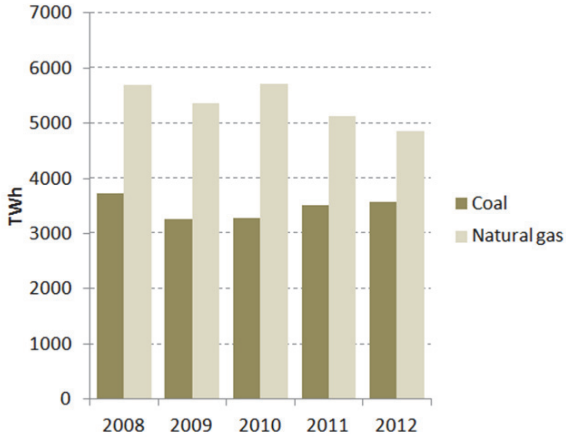

Figure 5. *Gross inland consumption levels of coal (hard coal and lignite) and natural gas in the EU-27 Source: Eurostat.*

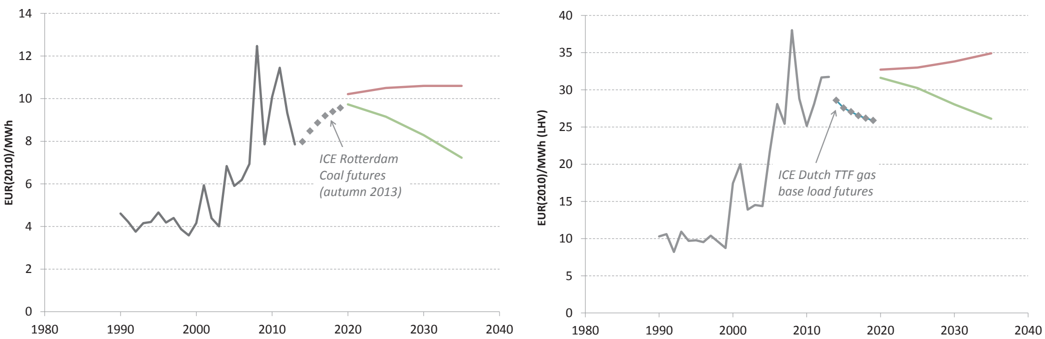

Figure 6. *Steam coal prices (OECD imports; left panel) and natural gas prices (European imports; right panel). Also included are two price projections for each fuel: one baseline projection (the upper projection towards Year 2035); and one global climate-mitigation scenario projection. Sources: ICE future prices; IEA World Energy Outlook 2013; BP Statistical Review of World Energy 2013.*

A third reason, besides low prices in the ETS market and in the global coal market, for the decreased competitiveness of gas-fired electricity generation is the significant increase in renewable electricity capacity across the European Member States that has occurred in recent years. With current price relations, gas power generally places itself at the upper part of the merit order curve. Thus, the introduction of new renewable generation capacity through dedicated support schemes tends to lead to crowding-out of especially gas power due to the relatively high marginal costs. Furthermore, the dramatic expansion of photovoltaic (PV) cells, for example in Germany, implies that peak-load generation, i.e., gas power, faces the risk of reduced operation time, since PV electricity generation coincides with the peak load, which is especially pronounced during the Summer; see for example, Fraunhofer (2014). The interplay and competition between variable renewable electricity generation and conventional thermal power are the cornerstones of the research presented in this book. These topics will be thoroughly dealt with in the forthcoming chapters of this book.

The renewable energy directive (RED) – increasing the share of renewables across Europe

As mentioned before, the share of renewables, especially for electricity generation, has grown significantly in many EU Member States. In Year 2005, the RES share of total gross consumption was approximately 9%. By Year 2011, the share had grown to 13% (Figure 7). By Year 2020, the corresponding share will be, according to the EU Renewable Energy Directive (RED), 20% (EC, 2009c). According to the Member States NREAPs, 23 out of the, at that time, 27 Member States projected in Year 2010 that they would reach their binding renewable energy targets for Year 2020 on their own without making use of the co-operation mechanisms that are presented in the RED (EEA, 2013). Ten of the Member States were expecting a surplus of renewable energy by Year 2020. Taken together, the NREAPs indicate that the binding RES target will be fulfilled by Year 2020. However, a more recent analysis presents a somewhat different outlook (EC, 2013c), concluding that the Member States will need to increase their efforts even further if they are to achieve collectively the binding targets for Year 2020.

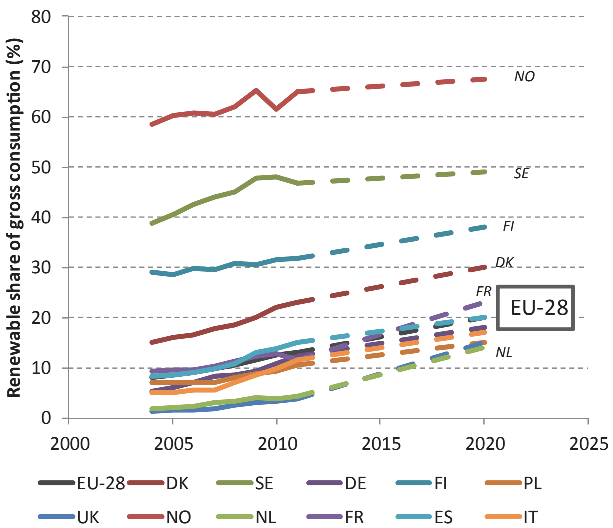

Figure 7. *Shares of renewables in the EU-28 and in selected EU Member States in terms of total gross energy consumption, and the targets for Year 2020, as stated in the Renewable Energy Directive (RED). Source: Eurostat.*

Efforts to meet the EU RES target are directed towards renewable energy in transport (RES-T), renewable heating and cooling (R-H/C), and renewable electricity (RES-E). In Year 2011, RES-E and RES-H/C accounted for 41% and 52%, respectively, of the RES volume in Year 2011 (which in turn corresponds to 13% of total gross energy consumption). By Year 2020, RES-E is expected to maintain its relative share, at around 42%. The largest relative increase is assumed to occur in transportation (RES-T), from 7% in Year 2011 to 12% by Year 2020. In the RES-E sector, the contribution from variable renewable electricity generation (vRES; solar power, wind power, tidal, wave and ocean energy) in particular is expected to grow significantly, from around 30% in Year 2011 to 50% in Year 2020 of the total RES-E volume (EEA, 2013).

The historic trend of renewable electricity generation, presented as the shares of gross electricity consumption, is shown in Figure 8 for selected Member States, Norway, and the entire EU-27. Some of these countries (e.g., Norway and Sweden) already have, thanks to abundant hydropower resources, large renewable shares. Other countries, such as Denmark, Germany, Spain, and Ireland, have increased their shares considerably since Year 1990 by extensive exploitation of other renewable resources, such as wind and solar power. The total share of RES-E in the EU-27 has grown from around 10% in Year 1990 to around 20% in Year 2011.

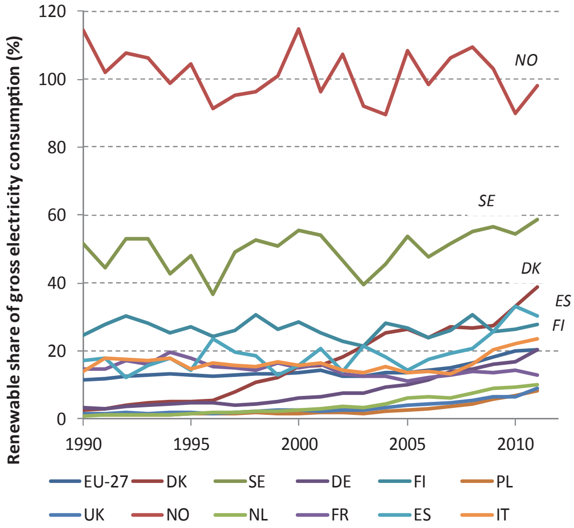

Figure 8. *Share of renewable electricity in relation to gross electricity consumption. Source: Eurostat.*

The rapid development of renewable electricity generation – the German case

In terms of the growth of installed RES-E capacity since Year 1990, Germany cannot be surpassed in the European perspective. The provision of generous support through feed-in tariffs regulated by the EEG (Erneuerbare Energien Gesetz), the renewable energy legislation, has led to a dramatic increase in RES-E capacity. This capacity has increased from around 5 GW in Year 1990 to almost 80 GW in Year 2012 (Figure 9), which is the same magnitude as the maximum peak load in 1 year in Germany. However, this rapid development has not occurred without controversies related to very high end-user costs, electricity-grid expansion (while development has been very fast on the production side, it has lagged behind significantly on the transmission and distribution sides), and the exemptions made for electricity-intensive industries (Handelsblatt, 2014). High end-user costs apply to households, commerce and a proportion of industrial consumers that finance the feed-in tariffs through electricity bills. These issues will have to be dealt with in during the revision of the renewable energy legislation that currently is subject to negotiations within the Year 2013 elected grand coalition. The exemptions for electricity-intensive industries have been queried by the EU Commission, which argues that the exclusion of German electricity-intensive industry from the EEG-Umlage, i.e., the additional fee charged in the electricity bill to finance the feed-in tariffs, is a violation of EU competition laws. Regardless, wholesale electricity prices have decreased substantially in Germany as a result of the dramatic increase in renewable capacity. Low wholesale electricity prices are of course beneficial for electricity-intensive industries, given that they not have to pay for the support of RES-E expansion.

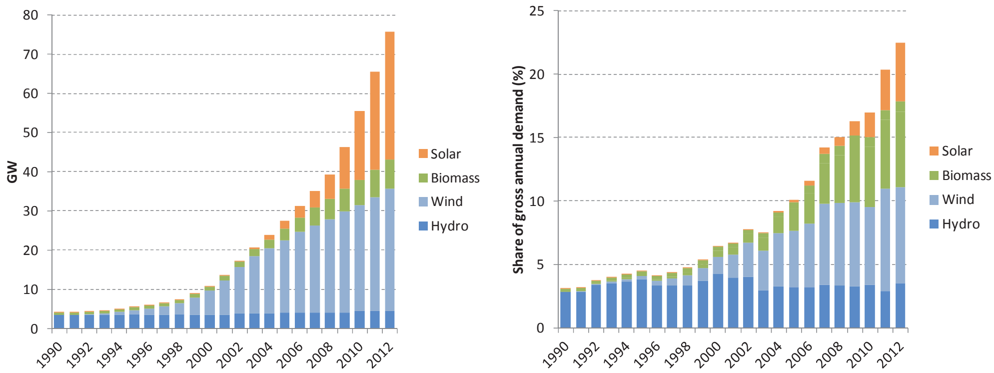

Figure 9. *Installed capacities of renewable electricity generation in Germany (left panel) and Germany's relative share of renewable electricity generation in relation to gross demand for electricity (right panel).*

Recent cost development in wind and solar power generation

As mentioned before, the growth in renewable electricity generation has been spurred by a variety of support schemes across the EU. In addition, this growth has been promoted by the significant reductions in purchase costs of RES technologies that have occurred over the past few years, especially in the case of PV cells. In Figure 10, the overall electricity-generation costs of PV cells (small-scale rooftop and large-scale stand-alone installations) are shown, as reported by the Fraunhofer Institute for German conditions during the past few years (Fraunhofer, 2013, 2012 and 2010). However, the total electricity-generation costs of PV installations remain far above the wholesale electricity prices (exemplified by the German spot price; the blue line in Figure 10). Nonetheless, grid parity may be within reach if PV electricity generation costs are compared with retail electricity prices, as this is a more appropriate profitability index for small-scale roof-top installations that are owned by private persons. In Figure 11, essentially the same information on the cost development of PV cells is given, but this time for Swedish conditions based on purchase-price observations (price per kW). As in the German case described above, small-scale installations in particular experience a rapid reduction in purchase costs.

The costs of wind power have not exhibited the same decrease as solar power over the past few years, which indicate that this technology has achieved a higher level of technology maturity (Figure 10, right panel). On the other hand, given the high global demand for wind power, the cost reductions achieved in the manufacture of wind turbines may not be completely reflected in the wind-turbine purchase price paid by the wind power owner or operator. Interestingly, the reported costs of offshore wind power seem to increase over time as experience in the use of this technology increases. It is likely that, for example, the maintenance costs of offshore installations in what are often very harsh weather conditions have been underestimated previously.

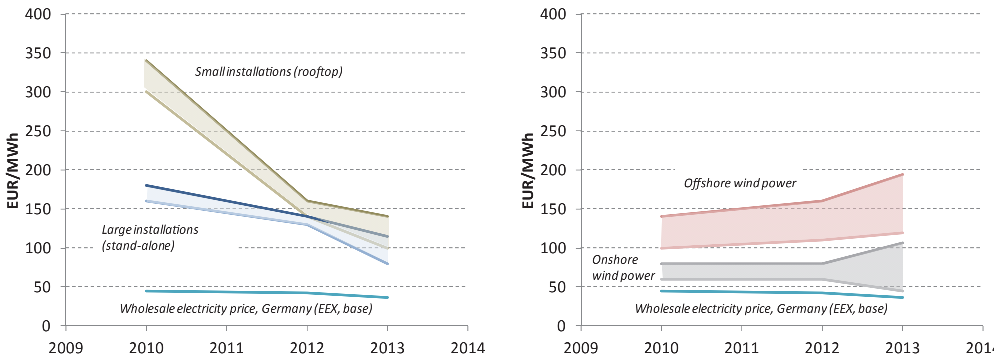

Figure 10. *Estimated electricity-generation costs (and intervals) of PV installations (left panel) and wind power (right panel) in Germany between 2010 and 2013. Source: Fraunhofer, 2013; 2012 and 2010.*

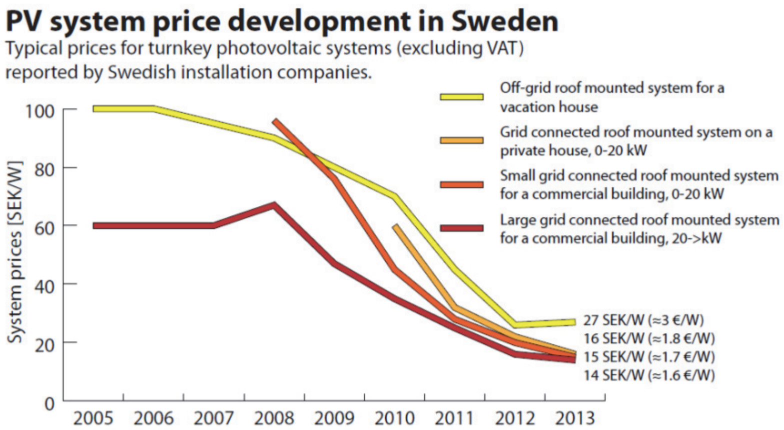

Figure 11. *PV system price development in Sweden, 1 € 9SEK. Source: IEA-PVPS, 2013.*

As mentioned above, the rapid integration of renewable energy and electricity is not without controversy. Certainly, while this development is desirable in terms of climate change mitigation, the associated challenges cannot be either neglected or underestimated. We have previously mentioned the relatively high costs for electricity consumers in Germany (as the example) that have resulted from the significant expansion of renewable electricity, which has been spurred by the German feed-in tariff scheme. Furthermore, variable renewable electricity capacity with a relatively low production-to-capacity ratio (compared to, for example, base-load thermal power plants) inevitably requires investments in additional transmission and distribution capacity if such electricity production is to be fully utilised (rather than suffer significant curtailment due to transmission bottlenecks). The issue of back-up capacity to cope with periods of low availability of wind and/or solar irradiation also needs to be considered carefully. Consequently, the interplay between variable renewable electricity generation (wind and solar) and conventional thermal electricity generation is the topic of Chapter 17 in this book. The extent to which large-scale integration of variable renewable electricity can be facilitated by increasing flexibility at the end-use side is the focus of Chapter 26. Whether or not the projected substantial use of renewable energy in the future will be entirely free of adverse climate effects is also a matter for debate. This and other issues are discussed in Chapters 4 and 5. Moreover, it is not uncommon for a clash to occur between the use of renewables for energy supply, e.g., biomass extraction and wind-power installations, and other land-use interests. Conflict areas related to wind-power exploitation are analysed in detail at different geographical levels in Chapters 8 and 22 of this book. All these challenges and considerations associated with the likely (and needed) substantial increase in the exploitation of renewable energy sources are important if the transition towards sustainable energy and electricity systems is to be accomplished in as efficient a manner as possible. As emphasised before, these are, among others, the issues and research topics that have been in focus throughout the research process. The following main sections and chapters of this book will unveil some of the findings and results of the research that relate to the prospects for large-scale integration of renewable electricity in the European electricity-supply system. However, before that, we need to address a number of additional issues that also have significance for this work.

The energy efficiency directive – the goal to increase efficiency and save energy

The third cornerstone of the EU energy and climate policy package is concerned with saving energy and increasing energy efficiency. The Energy Efficiency Directive (EED) entered into force on December 4, 2012 (EC, 2012). Most of its provisions are to be implemented by the Member States by June 2014 at the latest. The EED aims at meeting the target of reducing primary energy consumption by 20% by Year 2020, as compared with the baseline projection for the same year made in Year 2007. Rather than introduce binding targets at national levels, the EED instead contains binding measures, such as an obligation to renovate public buildings and other initiatives.

The Member States report their progress and their projections related to energy efficiency in the National Energy Efficiency Action Plans (NEEAPs) submitted to the Commission. The NEEAPs to be submitted by April 30, 2014 are supposed to cover a number of new elements, including reporting on progress towards the Year 2020 national targets and the adopted and/or planned energy efficiency measures to implement the EED (EC, 2014f). Based on these submissions, the Commission will review progress towards the 20% energy-efficiency target, report on it, and assess whether further measures are needed. If Europe is off-track in this regard, the Commission may come back with a proposal for further legislation (Euractive, 2014a).

In Year 2005, gross primary energy (PE) consumption (minus non-energy use) amounted to around 1700 Mtoe. Model runs initiated by the Commission from Year 2007 and for a business-as-usual scenario projected growth in gross PE consumption to 1842 Mtoe by Year 2020 (EU-25). This level sets the basis for the target of 20%, i.e., 1474 Mtoe, by Year 2020. Over the years, efficiency measures and policies have gradually increased the prospects for reaching that goal. Recent projections estimate a total primary consumption of <1600 Mtoe for the EU-27 (see Figure 12). Thus, even though the target seems to be within reach, we must not forget that the European economy still struggles with the effects of the global recession of 2008–2009. To proceed with reducing energy use towards the Year 2020 goal, additional measures are likely to be needed.

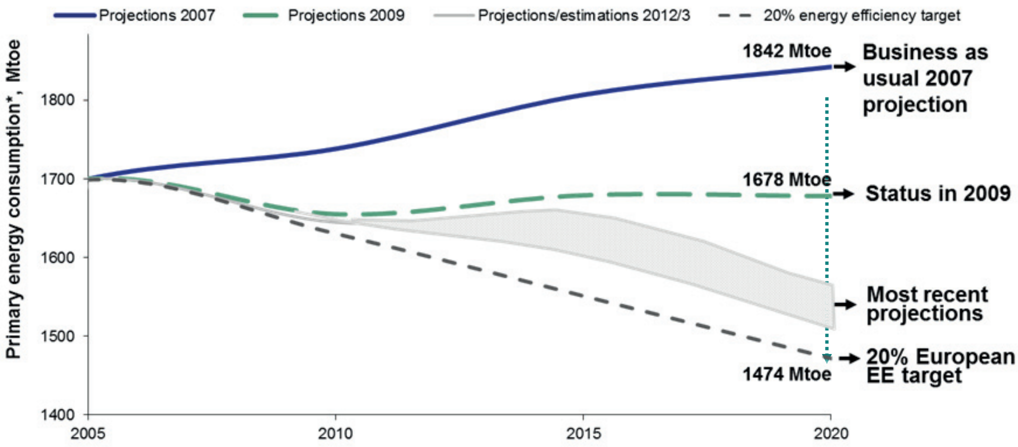

Figure 12. *Primary energy consumption target and projected consumption levels. Source: Miladinova (2013).*

The key features and measures of the EED (Euractive, 2014a) are:

- Energy sales from energy companies are to be reduced by 1.5% each year among the customers of the energy companies. This can be achieved by, for example, improved heating systems, fitting double-glazed windows, and insulating roofs.
- A requirement to renovate annually 3% of the buildings in the public sector that are owned and occupied by the central government in each country. To be covered by this requirement, the buildings need to have a useful area >500 m^2 (lowered to 250 m^2 as of July 2015).
- EU countries are requested to draw up a roadmap with the goal of making the entire buildings sector (including commercial, public, and private properties) more energy efficient by Year 2050.
- Energy audits and management plans are required for large companies, with cost-benefit analyses for the deployment of combined heat and power generation (CHP) and public procurement.

In one of the main scenarios of the research presented in this book, we have aimed to reflect the consequences of the EED and of increased savings in energy use also post-2020. However, research studies on the impacts of ambitious efficiency and conservation policies across Europe that include all sectors are scarce. Estimates of cost-efficient efficiency and conservation measures in the building stocks of selected European Member States are, however, a key component in the research of this book. More information on this can be found in the "*The demand-side perspective*" main section (see e.g. Chapter 27) of the present book.

European energy and climate policy: a single common framework or a regionalised patchwork of frameworks?

One of the driving forces of the EU is the idea of the "four freedoms" as cornerstones of a single European market. These four freedoms include the free movement of goods, services, capital, and people. This also applies to the field of energy, where the markets for e.g., electricity and gas are becoming increasingly integrated. Furthermore, it is argued by e.g. the European Commission that a common and integrated climate and energy policy framework would be a natural complement to such an increased European integration. Areas in which EU common legislation and policy instruments exist include the EcoDesign Directive on minimum performance standards and the application of energy labelling to certain energy-consuming products that are marketed and sold across the EU. The EU-wide trading scheme for emission allowances is another example. However, there are significant differences between the countries when it comes to other policy measures and instruments, such as energy-related taxes and support for renewables. Currently, there are few signs of harmonisation of the RES-E support schemes, despite the fact that the Commission has expressed such an ambition for years (see for example EC 2008). Different set-ups in relation to feed-in schemes, certificate trading, production subsides, and investment supports are in use across the EU. Furthermore, the EU ETS is subject to a certain degree of regionalisation, since, for example, the UK has introduced a carbon floor price as a top-up tax that is levied in addition to the EUA price. The price floor was set to increase each year from £16 per tonne of CO_2 in Year 2013 to around £70 by Year 2030; currently, this is well above the market price of EUA. The different RES-E support schemes in use today across the EU are shown in Figure 13.

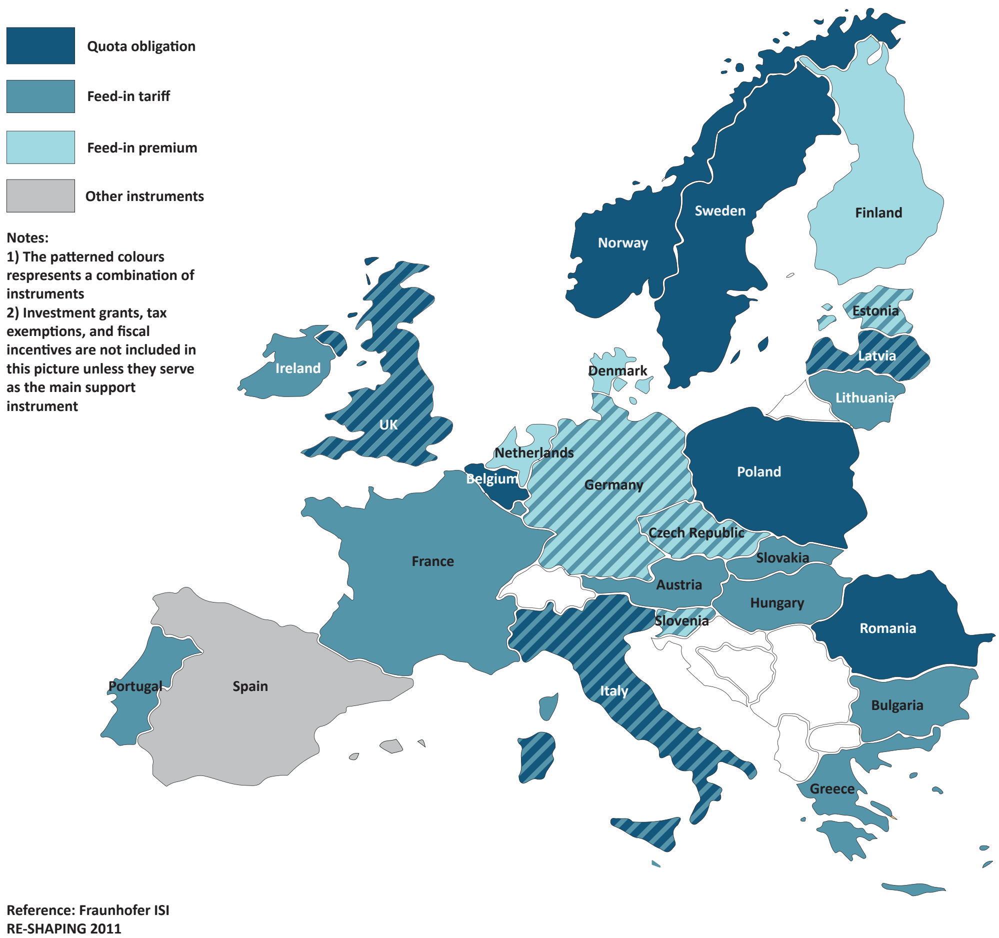

Figure 13. *Support schemes in use in 2011. Source: RES LEGAL Europe 2014.*

The contrast between a Europe that is largely united and synchronised in terms of climate and energy policy instruments and a Europe that is largely divided and fragmented when it comes to policy instruments is touched upon in the research presented in this book. European regionalisation versus European harmonisation of energy and climate policy is one of the dimensions that define the main scenarios for European electricity supply and that are analysed with the use of comprehensive energy systems modelling (see Chapter 10).

The existing European power plant capacity: investments in renewables and aging thermal power plants

For more than two decades, investments in new power plants across Europe have predominantly been made in gas-fired plants and renewable electricity generation (see Figure 14). This is in clear contrast to the 1970s and 1980s when heavy investments were made in coal-fired and nuclear power. Furthermore, the capacity build-up in the last 10 years (2003-2013) has been dramatic from a historical perspective, with roughly twice as much investment in capacity as in the previous decades. This is mainly a result of the significant increase in renewable electricity-generation capacity, which has been spurred by different support schemes across Europe. Yet, for the RES technologies it should be kept in mind that the full-load hours, generally, are significantly lower than for thermal power plants. Thus, on an energy basis the fraction of RES-based electricity supply is less pronounced than shown in Figure 14.

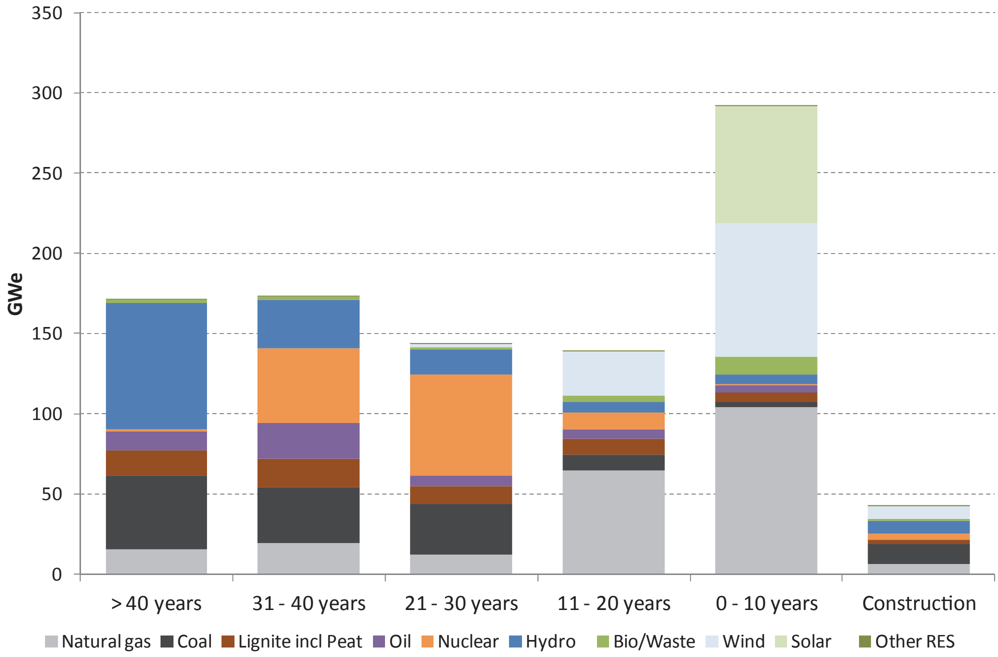

Figure 14. *Age distribution of existing power plants in the EU-28. Solar power and wind power plants under construction are, in principal, not included in the database. Source: Chalmers Power Plant Database, status March 2014.*

From Figure 14, it is clear that a large share of the thermal power plant fleet in Europe is of advanced vintage, i.e. approaching the end of its life-span. This is true especially for the nuclear and solid-fuel power plants. Figure 15 further underlines this by showing, as a supplementary way to represent the age distribution, that a little more than one-third of the existing thermal power plant capacity is *at least* 30 years old, and approximately two-thirds are *at least* 20 years old. In contrast, very few power plants are older than 50 years. Even if the technical life-time of a thermal power plant is largely plant-specific, the interval of 30–40 years is often referred to as a limit (see for example the assumptions made by IEA/ Nordic Energy Research, 2013). For nuclear power, 50–60 years is typically mentioned as the potential limit for the technical lifetime. Thus, large phase-outs due to age are likely to occur across Europe in the coming 10–20 years. Based on these somewhat rough lifetime assumptions, approximately half of the European thermal power plant capacity will be phased out due to aging before Year 2030. Meanwhile, the expansion of variable renewable electricity is likely to proceed at a rapid pace, which raises questions concerning the future availability of thermal back-up capacity.

Based on data on commissioning year of every single power plant across the EU, we conclude that in the coming decades phase-out due to aging is likely to initiate substantial investments in new capacity. Nevertheless, a significant proportion of the existing thermal capacity will be available for use for many years, which will have an important effect on the European electricity supply for years to come. Given the long lifetimes, the existing capacity is an important factor to consider when composing long-term energy and climate policies. Instead of arguing that approximately half of the European thermal power plant capacity will be phased out due to aging before Year 2030, one can, obviously, emphasise that the other half of this capacity is likely to still be available in Year 2030.

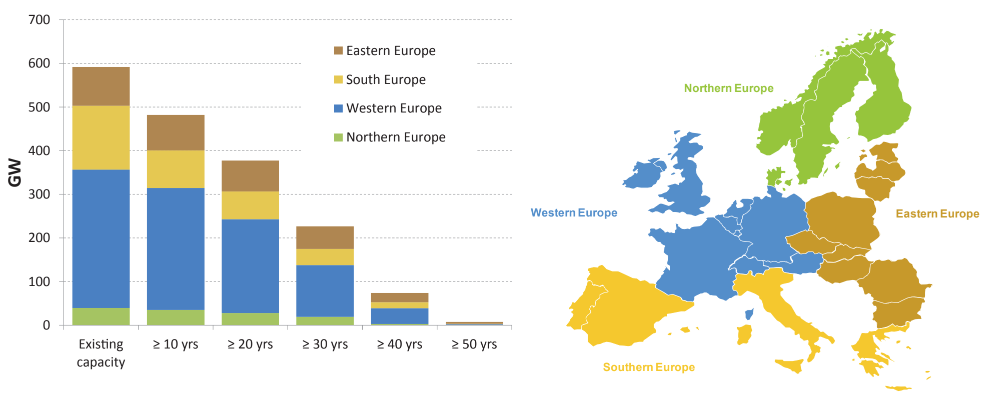

Figure 15. *Age distribution of existing thermal power plant capacity (including nuclear power) in Europe. Source: Chalmers Power Plant Database.*

The Large Combustion Plant Directive (LCPD)

The decommissioning of older power plants in Europe is further spurred by the Large Combustion Plant Directive (LCPD; Directive 2001/80/EC). This Directive concerns combustion plants with a rated thermal input of at least 50 MW, irrespective of the type of fuel used. The purpose of LCPD is to set limits to the amounts of SO_2, NO_x, and dust emitted from large combustion plants each year (EC, 2001). Thus, GHG emissions are not included. The LCPD requires power plants to either opt-in through environmental retrofitting and continue operation or opt-out and close down by Year 2016 at the latest. It is foreseen that a considerate share of power plants will fall under the latter category.

The largest regional impact of the LCPD will be on power plants in the UK in terms of decommissioning. Estimates based on data from the Chalmers Power Plant Database reveal that around 12 GW of electrical capacity will be decommissioned in the UK alone. This corresponds to approximately 15% of the total installed electricity-generating capacity in the UK. A little more than 7 GW of that capacity has already been decommissioned by Year 2013, following the LCPD. The estimated impact of decommissioning across the EU (presented as thermal capacity) is shown in Figure 16.

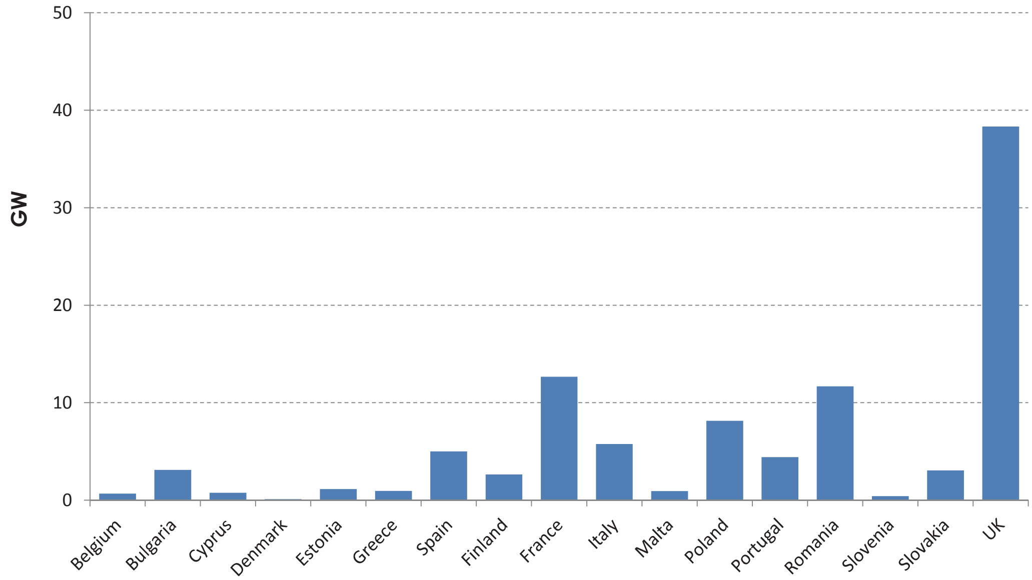

Figure 16. *Rated thermal capacity (in GW) of oil- and coal-fired power plants that will have to be shut down by Year 2015 in line with the LCPD (not all countries of the EU are affected. For instance, Germany has previously met the requirements through national regulations). Source: Chalmers Power Plant Database.*

Aging and decommissioning due to the LCPD or other reasons are included in the Chalmers Power Plant Database, which is an essential component of the research presented in the present book. The Chalmers Power Plant Database describes the status and important features of virtually all power plants across the EU. In the research process, age and decommissioning data on existing power plants have been integrated into the comprehensive European electricity system modelling used in different areas of the research. The modelling clearly shows an extensive reduction in generation capacity over the coming years, induced by aging and decommissioning. Thus, a gap between demand and supply will emerge and that will need to be filled with investments in new generation capacity. One example is shown in Figure 17, which presents the results for one of the four main scenarios presented in Chapter 10 of this book. This scenario assumes, among other things, continued growth in electricity demand. This assumption places extra pressure on new investments, as compared with a scenario with stagnating or declining electricity demand (also part of the scenario analyses presented in Chapter 10). According to Figure 17, approximately 30% of the existing electricity generation is phased-out due to aging or other reasons (such as unprofitability) by Year 2030. On the other hand the Chalmers Power Plant Database also shows, as we mentioned earlier, the long lived nature of the existing power plant stock which in the modelling remains far into the period towards year 2050. By Year 2050, the existing system can be expected to be in large part replaced by a new system.

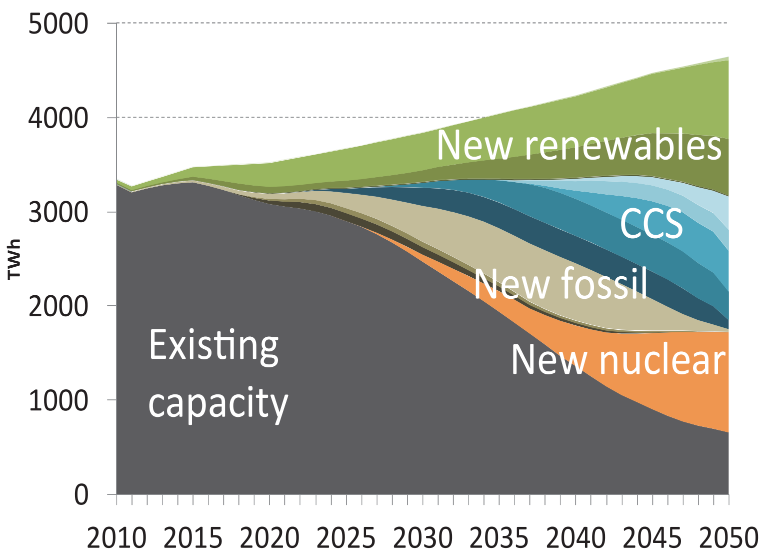

Figure 17. *European electricity generation subdivided into existing capacity and new capacity towards Years 2050 (model calculations based on Climate Market scenario assumptions; see Chapter 10).*

Status and prospects of Carbon Capture and Storage (CCS)

CCS is a key technology for climate change mitigation, especially in the global perspective. This is mainly due to the vast resources of fossil fuels, which if used would emit more CO_2 into the atmosphere than the climate system can cope with without a severe risk of increasing the global temperature by several degrees centigrade. Obviously, the fossil fuels have a high value for the countries that own these resources, and in the case of developing countries, which holds substantial percentage of known resources, it would be difficult to argue for such countries to leave these domestic assets in the ground. Thus, CCS can be seen as crucial for ensuring compliance with international CO_2 reduction treaties, since it would enable regions with fossil resources to exploit the value of these resources while maintaining security of supply. Based on the electricity-supply modelling reported in this book, CCS may become a very important component in the transition to a sustainable electricity system in Europe (see Figure 17 and upcoming Chapter 10). In addition, in other European energy systems modelling analyses, CCS was found to be an important supplier of electricity by Year 2050 (see for example, the PRIMES modelling related to EC Roadmap 2050; EC 2011c). However, from a European perspective, it is not as evident that CCS is required, and the debate and decision making related to CCS have in recent years been rather negative, e.g., the German federal ban on storage onshore. In addition, joint European large-scale demonstration projects (hundreds of megawatts) co-ordinated at the EU level have been put on hold, and only a few pilot projects of tens of megawatts have been realised.

From pilot projects and technology assessments, it is clear that it is not the technology itself that represents the barrier to its implementation, rather it is high costs, which are highly dependent upon the implementation strategy, as well as issues such as public acceptance and a lack of long-term policy framework that constitute more immediate barriers to entry. In addition, early cost estimates have proven to be too optimistic, in terms of the costs for the capture technology, as well as with regards to storage availability, acceptance, and the belief that the transportation of captured CO_2 to storage sites can be accomplished with large benefits from economies of scale. With respect to the costs for capture technologies, early estimates indicated 50–60% higher investment costs for coal- and lignite-fuelled power compared to a corresponding plant without capture (e.g., hard coal power without capture at ~1000 €/kWel, as compared to ~1600 €/kWel for hard coal power with capture), which would require a CO_2 emission allowance cost of about 30–50 €/tCO_2 resulting in an increase in the levelised cost of electricity from about 30 €/MWh to about 45 €/MWh (ENCAP, 2008). More recent work on capture costs indicates significantly higher investment costs both with and without capture. For examples, the EU project “Zero Emission Platform” has presented corresponding figures for a hard coal-fuelled power plant of about 1600 €/kWel without capture and about 2600 €/kWel with capture. This would require CO_2 emission allowance prices to be set at around 30–50 €/tCO_2, which is the same as the early estimates, although in this case the price of electricity increasing from 45 €/MWh to about 70€/MWh.

With respect to the options for storage, various studies have focussed on two areas: storage potential and costs for transportation and storage of CO_2. The storage potential concerns the storage space potentially available in different types of underground geological formations, such as depleted oil fields and aquifers, where new factors that are uncertain and site-specific are continuously added to the parameters that are required to assess the actual storage capacity. While the availability of CO_2 storage capacity seems sufficient, questions have been raised as to field injectivity, pressure build-up, and the overall field injection strategy (which will influence the overall storage capacity/volume in the field). Many of these factors are highly site-specific and difficult to know prior to field investigations. The second focus area, costs for transportation and storage of CO_2, involves studies on CO_2 pipeline infrastructure, which some 10–15 years ago indicated costs for transportation and storage of a couple of Euro per tonne (see for instance Svensson et al., 2004), based mainly on assumptions of the bulk pipeline systems being used at maximum design capacity. However, an important aspect that needs careful consideration during the establishment of a CO_2 infrastructure is the timing of investments, i.e., to obtain maximum benefits from a co-ordinated pipeline network, the building up of the power plants needs to be concentrated in a region as well as in time, to avoid time periods during which there is unused transportation capacity in the bulk pipeline. In addition, the costs for collecting pipelines (pipelines from power plants to the bulk network) and distribution pipelines (within the reservoir) are roughly equal to the cost of transportation in the bulk system. Thus, more recent work on transportation and storage costs gives values in the range of 5–15 €/tCO_2 for most European countries (Kjärstad et al., 2013). Another factor that is important for the transportation and storage costs is whether or not onshore storage is available as an option, even at costs that are substantially higher than those given in the early estimates.

Overall, for CCS to become a realistic alternative to conventional coal-fuelled power, CO_2 emissions need be priced in the range of 30–60 €/t, which would raise the cost of electricity by about 15–20 €/MWh. Based on this, CCS is likely to compete with (or supplement) alternative means of electricity generation, such as RES-E, in the future European electricity market. This is also shown in Chapter 10 of this book where we analyse different pathways of the European electricity-supply system. In the global perspective, CCS is likely to be an important technology that offers regions with large fossil assets (e.g., China), the possibility for continued use of domestic, abundant fossil resources without removing the ability to comply with emissions reduction targets, if implemented. Whether such a global diffusion of CCS may take place without substantial CCS investments in Europe is, however, less likely.

Nuclear power

In the research that is presented in this book, nuclear power is not specifically addressed. Instead, nuclear power is viewed as one of the many options for the future European electricity system. This means that the shares of, and the roles played by, nuclear power in the scenario analyses presented in succeeding chapters are primarily the results of assumed European energy and climate policies and the assumed profitability levels of new nuclear-power plants (as given by the cost assumptions of nuclear power). This is, of course, also the case for other competing technologies. Whereas our research has generated detailed knowledge as to the exploitation of e.g. wind power and CCS, nuclear power has not received the same attention.

A controversial technology

Opinions regarding nuclear power are divisive among people and among governments. Germany is probably the best-known example of a country that has significantly changed its nuclear policy as a direct consequence of the Fukushima accident in Japan in Year 2011. According to a governmental decision, which was subsequently approved by the German parliament, all nuclear power plants are to be closed by the end of Year 2022. In addition, Switzerland and Belgium have made governmental decisions to phase-out their nuclear power capacities. In these countries, no final phase-out year has been defined. In Switzerland, Year 2034 is mentioned as a potential final phase-out year, since the newest reactor will by then have reached its life-time limit of 50 years. Italy, which currently has no nuclear power plants, had substantial plans for such investments prior to the Fukushima accident. After the accident, all these plans were abandoned. For the rest of Europe, the view on nuclear power is somewhat more ambiguous. In Finland, the UK, Poland, and the Czech Republic plans for new nuclear power plants are more or less advanced. Currently (Year 2014), there are four nuclear power plants under construction in Europe: one in Finland (Olkiluoto 3); one in France (Flamanville 3); and two in Slovakia (Mochovce-3 and Mochovce-4). All four projects have, to various degrees, suffered from increasing costs, delays, and other construction-related problems (World Nuclear Association, 2014). This emphasises the challenges that are associated with building new nuclear power plants and indicates the long lead times that need to be considered. Nevertheless, in a stringent European climate regime towards Year 2050, several studies have come to the conclusion that new nuclear power plants, or lifetime extensions of existing plants, are likely to be needed alongside investments in renewable electricity generation and possibly CCS. All the decarbonisation scenarios in the PRIMES Energy Roadmap 2050 model runs include, to various extents, nuclear power by Year 2050 (EC, 2011c).

The European nuclear power plant fleet

In Figure 18, we present the nuclear power plants (sites) that are currently in operation across the EU-27 and Switzerland. The age distribution of these plants is reported in Figure 19. We conclude that in 15 years time, roughly 80% of the nuclear power plants in Europe will be older than 40 years.

__Figure 18.__ Nuclear power plants (sites) currently in operation in the EU-27 and Switzerland (2013). Source: Chalmers Power Plant Database.

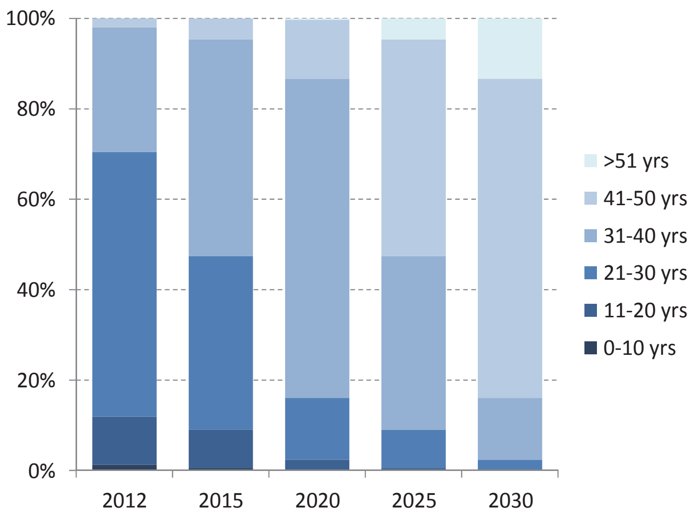

__Figure 19.__ Age distributions of the existing nuclear power plants in the EU-27 and Switzerland for different years. Source: Chalmers Power Plant Database.

Figure 20 presents another view of the subject of nuclear power in Europe. Under the assumption that all nuclear power plants currently in operation have a total technical lifetime of 60 years, we can produce a phase-out curve for the entire nuclear capacity. Apart from the four reactors that are currently under construction, we assume that no new plants enter into operation. In Germany, the phase-out of nuclear power plants follows the governmental decision and not the assumption of 60 years of technical lifetime. Given these assumptions, only around 20 GW of the existing 130 GW would still be in operation by Year 2050. From Figure 20, we can also conclude that the absolute lion's share of the existing capacity was commissioned between 1980 and 1990. This indicates that the engineering, manufacturing, and financial capacities, at least in a historic perspective, for such huge investments over a relatively limited period have been of considerable size. We will show, in forthcoming chapters, that such massive investments, albeit not primarily in nuclear power, for limited periods of time will also be needed in the coming decades.

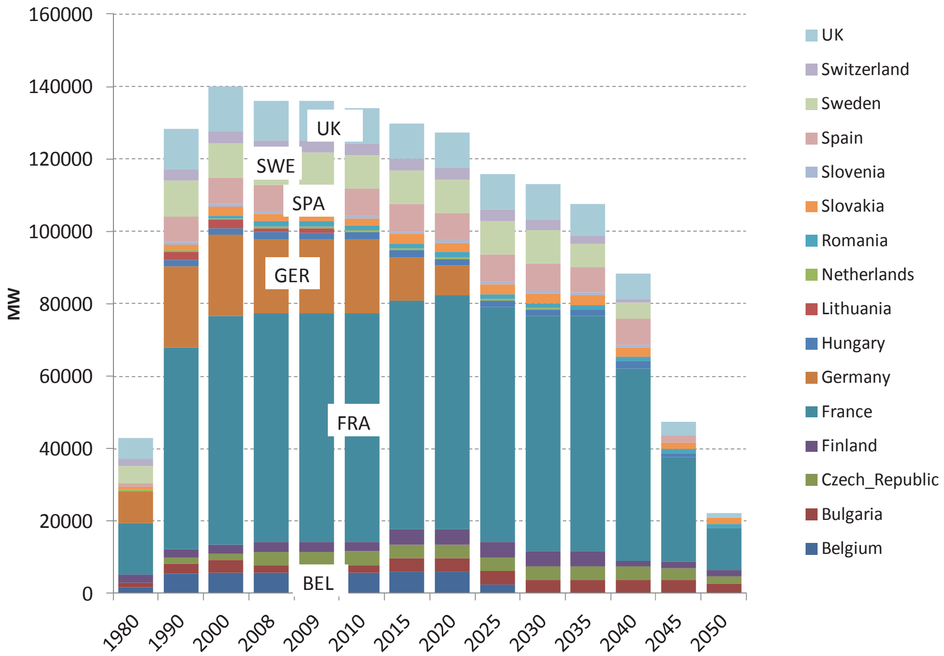

Figure 20. *Estimated phase-out of existing nuclear power plants based on age (assumed technical lifetime of 60 years) or policy (in Germany). Sources: Eurelectric and Chalmers Power Plant Database.*

Costs of nuclear power

Estimates of the costs of nuclear power vary widely between different sources. Due to the very low activity in nuclear investments in the Western world, sufficient experience as to costs is, obviously, lacking for Western conditions. At the same time as opponents of nuclear power point to the fact that the few projects under construction suffer heavily from delays and significant cost increases, proponents of nuclear power claim that once global investments take off and the nuclear manufacturing industry gets the opportunity to produce many plants, construction costs will decrease.

According to a recent WEC study (WEC 2013), current overall generation cost estimates for new nuclear power are in the range of 75–115 €/MWh electricity produced, depending on the region studied.[4] The median value lies at the lower end of that interval. The same source estimates corresponding costs for onshore wind power of 40–150 €/MWh, depending on the region, with a median value of around 60 €/MWh. New natural gas power lies in the interval of 45 – 110 €/MWh, with a median value of 50 €/MWh. Thus, in this context, new nuclear power is seemingly less profitable than new wind power or new natural gas-fired combined cycle schemes (CCGT), at least when comparing the median cost estimates. The Nordic Energy Technology Perspectives project conducted by the IEA has a somewhat more optimistic view of the overall generation costs of nuclear power. In that study, approximately 50 €/MWh was assumed as the representative levelised cost of electricity for new nuclear power plants (IEA, 2013).[5] As a comparison, the same study estimated the costs of new onshore wind power to be in the interval of 50–100 €/MWh, depending on the region and wind availability. Wind-power generation costs are, however, assumed to decline over time due to technological developments (this is not assumed for nuclear power). Electricity generated from new CCGT is estimated to cost approximately 50 €/MWh, with a tendency for the cost to increase over time due to increased gas prices. Thus, in contrast to the former estimates made by WEC, the IEA study assumes relatively strong competitiveness for nuclear power in relation to other technologies.

Another indication of the high costs of generation in new nuclear power plants is the set guaranteed feed-in price for the planned Hinkley Point C plant, which will be operated by EdF in the UK. For that investment, the UK government has guaranteed a fixed price of £92.50 per MWh (roughly 110 €/MWh). This is approximately twice as high as the current wholesale price of electricity in the UK (Financial Times, 2013). However, this arrangement is at the time of writing subject to investigation by the EU concerning possible violations of EU competition laws.

[4] Costs are originally expressed in USD/MWh. We have used the exchange rate of 0.75 €/USD.

[5] As in the study carried out by the WEC, original costs are expressed in USD/MWh. We have used the exchange rate of 0.75 €/USD.

It is obvious that current cost estimates in relation to new nuclear power plants are very uncertain. Lead times and construction times are generally long, adding to the investment uncertainty and risk. Thus, we conclude that two non-renewable, albeit climate-benign, key technologies, nuclear power and CCS, are subject to large uncertainties and, most likely, very high up-front investment costs. These factors add to the challenge of transforming our electricity and energy systems towards significantly reduced emissions of greenhouse gases.

Final remarks

This main section of the book sets the scene for the research results in the upcoming sections and chapters. We have, among other things, elaborated on the multitude of policy goals and measures that are in place at the European level, with significant differences in set-ups between Member States, to drive the energy and electricity systems towards sustainability. Currently, the main impact of policy seems to be most in the field of renewable energy. This is one explanation for the low steering effect currently observed in the EU ETS market. The price signal from the EU ETS market must become significantly stronger if GHG emissions are to be reduced substantially and in an efficient manner. We show that the contribution of renewable electricity will increase steadily, which is essential to meet the policy targets defined for Year 2050. At the same time, the challenges to integrate that generation, which often varies considerably in terms of production levels, will obviously increase. Several of the coming chapters will present a closer inspection of these issues.

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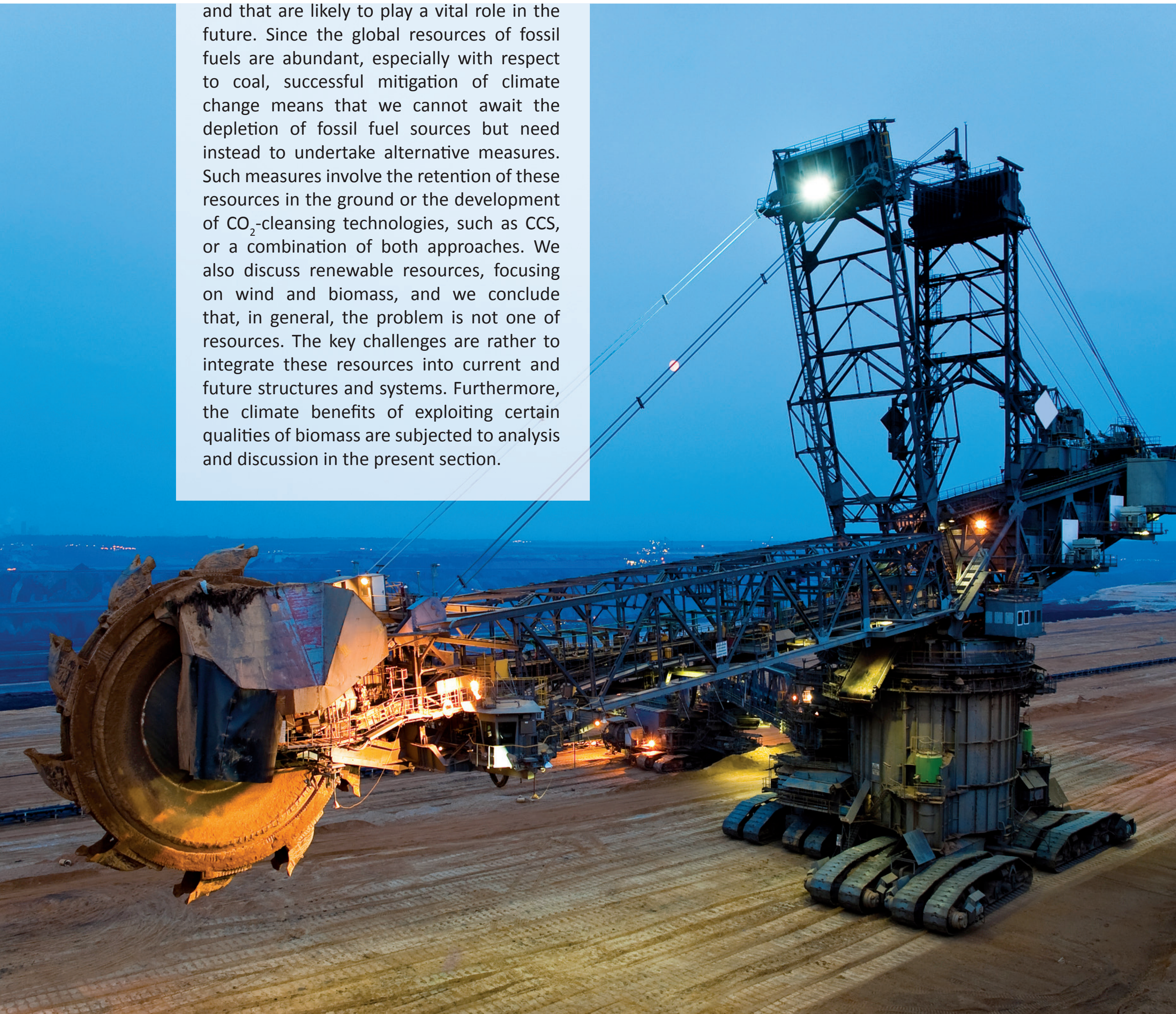
Resources

In this section, we focus on selected resources that are essential for the existing European (and global) energy systems and that are likely to play a vital role in the future. Since the global resources of fossil fuels are abundant, especially with respect to coal, successful mitigation of climate change means that we cannot await the depletion of fossil fuel sources but need instead to undertake alternative measures. Such measures involve the retention of these resources in the ground or the development of CO_2-cleansing technologies, such as CCS, or a combination of both approaches. We also discuss renewable resources, focusing on wind and biomass, and we conclude that, in general, the problem is not one of resources. The key challenges are rather to integrate these resources into current and future structures and systems. Furthermore, the climate benefits of exploiting certain qualities of biomass are subjected to analysis and discussion in the present section.



1 The geopolitics of renewable energy and abundance of fossil fuels

To what extent can technologies based on renewable energy sources (RES) be expected to substitute for fossil fuels so that the use of fossil fuels is reduced? This chapter summarises a study which discusses the developments related to fuel mixes in electricity generation over the last decade, and compares regions that have extensive and scarce domestic fossil fuel resources. There has been significant expansion of renewable electricity generation, although in terms of growth in absolute numbers, this increase is in most regions dwarfed by the even larger increase in fossil fuel-based electricity generation. This is particularly true for developing countries that are rich in domestic fossil fuel resources. A possible "fossil-fuel curse" is identified, which implies that countries with large domestic fossil fuel resources cannot be expected to allow these resources to become stranded assets. As a consequence, this represents a significant threat to the mitigation of human activity-induced global warming.

An abundance of fossil fuel reserves

State-of-the-art research indicates that reductions of 50%–70% in greenhouse gas (GHG) emissions by Year 2050 are required to limit the global temperature increase to 2ºC (Fee et al., 2010). Emissions must of course continue to be low after year 2050 in order to meet target. Such reduction obviously entails enormous technical and political challenges. Figure 1.1 compares a carbon budget for 2ºC warming with the carbon content in the global fossil fuel reserves and the reserves with 30% of the resource base added. It is clear that only a fraction of the available fossil fuels can be allowed to be burnt if severe warming of the planet is to be avoided. This suggests that it is not a scarcity of fossil fuels *per se* that will drive efforts to reduce CO_2 emissions that originate from fossil fuels.

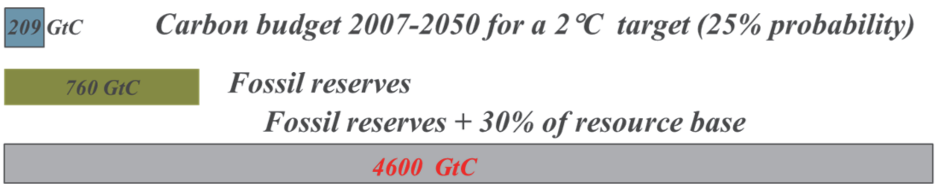


Figure 1.1. *The carbon budget for a target of 2ºC increase in temperature (blue bar), as given by Meinshausen (2009) (if limiting global warming to 2ºC), together with the potential emission levels from the global fossil fuel reserves (green bar) and these reserves plus 30% of the resource base (grey bar). Adapted from Kjärstad and Johnsson (2012).*

To reduce CO_2 emissions from the energy sector, investments in renewable energy technologies, as well as in specific renewable electricity generation [hydropower and non-hydro renewable energy (NHRES)], are often considered as key options. In recent decades, hydropower has undergone strong growth in developing regions, such as China and India (IEA, 2012a). However, it can be considered as an established technology that has limited potential for further expansion in developed regions, such as the EU and the US. Thus, in a future perspective, large-scale diffusion of NHRES technologies (to replace fossil-based technologies) is considered crucial for decarbonisation of the energy system.

Have renewables been substituted for fossil fuels?

In recent decades, there has been strong expansion of NHRES technologies in several regions around the world. In general, the main investments in NHRES has been in wind and solar power; in Europe, there has been a more than four-fold increase in installed wind capacity over the past decade, accounting for 106 GW in the EU-27 by the end of Year 2012 (EWEA, 2013). In recent years, there has also been strong expansion of wind power in China, with 75 GW installed capacity at the end of Year 2012 (Global Wind Energy Council, 2013). In several countries, wind power capacity additions (in GW) have exceeded investments in thermal electricity generation. There has also been significant expansion of solar power (in the end of Year 2013, the world's cumulative PV capacity was >130 GW; EPIA, 2014). Nevertheless, the use of renewable energy remains small, as compared with the use of fossil fuels. In addition, fossil fuels are abundant, showing continued and increasing use in many regions. Fossil fuels still account for more than 80% of the global primary energy supply (DOE, 2010). Thus, considering that the main reasons for expansion of NHRES technologies are to mitigate CO_2 emissions and to increase security of supply, an obvious question is whether these measures can be expected to reduce the use of fossil fuels rather than just adding capacity or whether, along with fossil fuels, they will contribute to meet the increasing demand for energy. This begs the question as to whether there are any examples of countries that have replaced fossil fuels through the implementation of NHRES technologies (or with hydropower), in the sense that the extraction of their fossil fuel resources has been correspondingly decreased, i.e., they have been left in the ground.

This chapter summarises a study (Kjärstad and Johnsson, 2013) that addressed this issue by comparing the development of NHRES (and hydro) technologies with the use of fossil fuels in key regions, including those with large domestic resources of fossil fuels and those with few such resources. In this context, the changes in fuel mixes for both primary energy consumption and electricity generation were investigated, although in this chapter, the focus of our discussion is electricity generation, as this is the main topic of this book.

A survey was conducted of key regions with extensive (China, India, Norway, Russia and the US) or negligible domestic resources of fossil fuels (EU-27, Germany, and Japan). For each region, the economic value of the national fossil fuel resources is estimated, and calculations are made of the indicators that specify the annual production of fossil fuels, as well as the indigenous fossil fuel supply (reserves plus 30% of the resource base) in comparison with annual GDP. The economic value of the domestic fossil fuels is estimated by simply multiplying the reserves and resources by the current prices of coal, oil, and gas, so as to derive an approximate relation between the resources available and their economic value. The 30% of reserves is arbitrarily chosen to reflect the likelihood that part of the extensive resource base may also be used, which, considering Figure 1.1, is obviously a significant threat to efforts to mitigate human-induced climate change.

Domestic fossil resources

Table 1.1 lists the key values for the domestic fossil fuels (coal, oil, and gas) in the regions investigated. China, India, Norway, Russia and the US all have large domestic fossil fuel resources, represented by high economic values and adding to their security of supply. Coal is the predominating fuel, except for Norway where most of the domestic fossil resources are in the form of natural gas and oil and where most of the economic value is realised through exports. The economic value of one year of production (Year 2011) ranges from 3.3% to 34.6% of the GDP of these countries. While this is a broad range, with the 34.6% value representing a large fraction of GDP, also the 3.3% value can be considered as a significant portion of the annual GDP, since it represents a “single” industry (the fossil fuel industry). The economic values of the reserves plus 30% of the resource base for the developing economies of China, India, and Russia are 33-, 10-, and 95-times GDP, respectively. Thus, for these regions, the domestic fuels obviously represent very high values. Overall, it is clear that the large reserves and resources represent valuable economic assets for these countries.

For EU including Germany, the picture is different, as the domestic fossil fuel resources are much less-extensive, with Germany having some lignite and the EU together having a mixture of mainly natural gas and lignite. For Germany and the EU, the economic value represented by fossil fuels is significant, although far less significant than those for China, India, Norway, Russia, and the US. Japan has almost no indigenous fossil resources (having only limited amounts of gas) and has a high import dependency, i.e., a situation opposite that of Norway where the major part of the domestic fossil fuel production (gas and oil) is exported.

Table 1.1. Reserves and resources of domestic fossil fuels for the regions investigated in this work, together with estimates of the corresponding economic values and their relationships to GDP.							
Fossil fuels (coal, oil and gas)	Energy content [EJ][a]		Economic value [10^9 USD][b]			Economic value as share of GDP[c]	
	Reserves	Reserves +30% of resource base	Reserves	Reserves +30% of resource base	Year 2011 produc-tion	Year 2011 produc-tion	Reserves + 30% of resource base
China	5 254	48 627	26 164	239 058	643	0.088	33
EU-27	1 066	5 784	5 935	28 651	156	0.012	2.2
Germany	372	1 185	1 683	5 366	14.8	0.004	1.5
India	2 584	4 462	10 821	19 144	131	0.07	10.2
Japan	10.2	120	59	578	2.6	0.0004	0.098
Norway	118	194	1 410	2 350	110	0.22	4.8
Russia	5 622	36 629	39 322	179 993	658	0.35	95
US	7 384	70 056	34 634	309 981	494	0.033	21

[a] Data from DERA (2012)
[b] Economic values of the domestic fossil fuels are roughly estimated by multiplying reserves and resources with the Year 2011 prices of coal, oil and gas as given in IEA (2012a)
[c] GDP values from World Bank (2013)

The use of fossil fuels is on the increase

Table 1.2 summarises the developments that have occurred in the electricity generation sectors of the analysed regions, including growth for the period 2004–2011. From the values listed, it can be concluded that for the regions rich in fossil fuels (China, India, Norway, Russia and US), the amount of electricity from NHRES is in the order of a few percent of total generation: China, 2.4%; India, 5.0%; Norway, 1%; Russia, 0.3% and US, 5.1%. However, China and India, as well as the EU and Germany have seen strong growth of NHRES electricity over the past decade. For the US, the 5.1% electricity from NHRES, has been in place for a longer time period, mainly as a measure to increase security of supply. Thus, although there has been a large increase in NHRES in the US during the last decade, the level of NHRES in Year 1990 was higher than the corresponding levels in the other countries. Thus, a substantial fraction of the NHRES in the US was installed as a response to the oil crises in the 1970s. For Norway, there is very little NHRES which, as indicated above, is due to the fact that Norway generates almost all of its electricity from hydro. The almost 100% renewable Norwegian electricity generation system was mostly established before Norway became a fossil fuel-producing/-exporting country.

Given the recent growth trend (2004–2011), it is clear that for the fossil-rich countries that can be considered as developing economies (China, India, and Russia), the growth of fossil fuel-based electricity generation is much higher than the growth of NHRES generation *in terms of growth in absolute numbers*, as given in the present work (in TWh). Even in Norway, the growth of fossil fuel-based generation is higher than the growth of NHRES (the variation in hydropower generation reflect to a large extent precipitation). Only in the US is the recent growth of generation from NHRES exceeded by that of fossil fuel-based electricity generation, despite the fact that the US has large fossil fuel resources. Nonetheless, with the new technologies (and reduced costs) for extracting shale gas and the significant growth currently occurring in this sector, it is questionable whether this growth pattern will prevail. For the EU including Germany, i.e., regions with low levels of fossil fuels, the growth of electricity generation from NHRES is significantly higher than the growth of fossil fuel generation. In fact, as can be seen in Table 1.2, there was a reduction in fossil fuel-based electricity generation in the EU, as well as in Germany in the period 2004–2011. Although Germany has started to transform its energy system according to the "Energiewende" targeting an electricity generation system that is almost entirely based on renewable sources, the drop in coal prices has resulted in an increase in coal-based electricity generation in recent years (Platts, 2013). Considering the slow-down in the development of carbon capture and storage (CCS), it is not clear what will happen with the German lignite-fired power plants. If CO_2 emission reduction targets are to be met, the domestic lignite resources have to be turned into stranded assets at some point in the not so distant future, unless the lignite-fired plants can be equipped with CCS technologies. However, there are presently few economic incentives for developing and implementing CCS and public acceptance of CCS seems low in Germany, especially with respect to CCS schemes that involve on-shore storage.

Although Japan has the fewest assets in terms of domestic fossil fuels of the regions investigated, fuel-based electricity generation has increased at a rate that is several times higher than that of NHRES during the period 2004–2011. Thus, there has been a trend towards increasing import dependency in Japan (exacerbated by the shut-downs of nuclear power facilities following the earthquakes in Year 2011). It can be expected that Japan will put more effort into developing NHRES technologies and energy conservation measures that suit the Japanese infrastructure, which on the other hand will pose challenges to the grid and balancing capabilities.

Table 1.2. Electricity generation [TWh] from fossil fuels, NHRES technologies and hydro. Data from IEA (2012).

	Electricity generation [TWh]											
	1990			2004			2011			Δ (2004 -2011)		
	Fossil fuels	NHRES	Hydro	Fossil fuels	NHRES	Hydro	Fossil fuels	NHRES	Hydro	Fossil fuels	NHRES	Hydro
China	523	0	127	1 830	2	354	3 854	115.3	699	2 024	113.3	345
EU-27	1 462	25.0	286	1 776[a]	133[a]	357[a]	1 654	384.5	311.2	-122[a]	251[a]	-45.8[a]
Germany	372.4	4.9	17.5	385.1	43.0	19.6	362	115.1	17.5	-23.1	72.1	-2.1
India	212.0	0	72.0	560.0	6.0	85.0	835.7	52.7	130.7	275.7	46.7	45.7
Japan	532.0	13.0	89.0	671.0	23.0	94.0	808.4	49.3	83.2	137.4	26.3	-10.8
Norway[b]	0.1	0.4	121.1	0.4	0.3	138.9	4.4[b]	1.3[b]	126.3[b]	4.0[b]	1.0[b]	-12.6[b,c]
Russia	798.0	0	166	604.0	2.0	176	710.9	3.3	165.8	106.9	1.3	-10.2
US	2 213	106	273	2 961	102	271	2961	222.4	321.7	0	120.4	50.7

[a] Values for 2004 are taken from Eurostat (2010).
[b] Values listed under the categories '2004' and '2011' are from Year 2000 and Year 2009, respectively (IEA, 2011).
[c] Variations in Norway are partly due to precipitation differences, i.e. inflow to hydropower, rather than related to changes in generation capacity

The "fossil-fuel curse"

For China, India, and Russia, all of which have large domestic resources of fossil fuels and significant economic development, not only electricity generation, but also primary energy consumption from fossil fuels have increased more than electricity generation and primary energy consumption from NHRES. In fact, for these countries, there has been no increase in primary energy use from NHRES in the last decade (with a significant decrease in India). This underscores how challenging it will be to replace fossil fuels with renewable energy sources, since leaving the fossil fuels in the ground will represent significant stranded assets. In analogy to the notion of a "Natural Resource Curse" (cf. Sachs and Warner, 2001 and references therein), we identify a potential "fossil-fuel curse", which states that countries with large resources of fossil fuels cannot be expected to make these resources stranded assets. Thus, this represents a significant threat to efforts to mitigate human activity-induced global warming.

In summary, fossil fuels have by their very nature high energy contents, and until CO_2 emissions and other external environmental effects of extracting and using fossil fuels are not priced sufficiently or until RES technologies are available in abundance at sufficiently low cost, it cannot be expected that the fossil assets will remain in the ground.

We conclude that it is remarkable that there is little work on the geopolitics of fossil fuels in a climate change context. A more comprehensive analysis in a natural-resource economics perspective is required to analyse the total impact and value for society, such as that expressed by the concept of natural (fossil fuel) resource rent. Such work should include analysis of the economic value of fossil fuels with respect to the geopolitics of climate change mitigation.

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2 Unconventional gas and its potential impact on global gas markets

There exist significant global resources of conventional and unconventional natural gas. However, estimates of the recoverable levels of unconventional gas, including shale gas, are very uncertain for all regions of the world, and the prospects for production of unconventional gas in Europe are highly uncertain. We believe that there will be no "abundance of natural gas" on global markets until late in this decade at the earliest. In addition, European gas prices will be increasingly de-linked from oil prices, with spot trading attaining greater importance. In the scenario investigated (assuming good prospect for natural gas at competitive price levels, see Chapter 12 for more details), natural gas consumption in the European power sector (EU-27 plus Norway and Switzerland) increases from 181 billion cubic metres (bcm) in 2010 to reach a peak of 305 bcm in 2030, with the major increase occurring in the period from 2020 to 2030. The increase in gas consumption should not be critical with respect to supply, although it will probably lead to an increased dependency of the EU on imports.

Over the last few years it has become apparent that substantial resources of conventional gas, together with potentially significant resources of unconventional gas may lead to natural gas becoming increasingly competitive over the coming decade. This development would support a large expansion in gas-based power without compromising the security of supply. In this chapter the first section assesses the prospects for increased gas resources while the upcoming sections focus on the implications this would have on the European power sector.

Natural gas resources

This section presents the results of the assessment of the global gas market. This analysis serves as the basis for several of the inputs to the modelling presented later in this book. The results of the modelling of the European electricity generation sector, assuming good prospects of natural gas supply including competitive price levels compared to coal, can be found in Chapter 12.

The production of unconventional gas (shale gas, tight gas, and coalbed methane [CBM]) is concentrated in North America, primarily in the US. Almost 90% of unconventional gas production in 2011 occurred in North America and the production of tight gas still exceeds the production of shale gas according to IEA (2012b).

The magnitudes of Ultimately Recoverable Resources (URR) of unconventional gas are highly uncertain, even in the US. For instance, the US Energy Information Administration reduced their estimate of Technically Recoverable Resources (TRR) in the US by more than 40% over the course of 2012, claiming that in their calculations they had applied more recent drilling and production data that became available through 2011. Nevertheless, the resource is large at almost 14 trillion (10^{12}) cubic metres (Tcm), corresponding to almost 40 years of production of unconventional gas in the US at 2010 levels, and with a considerable upside of the resource base (EIA, 2011; EIA, 2012).

As indicated above, estimates of unconventional gas resources vary considerably also for regions other than the US, as illustrated by a study conducted by the Joint Research Centre (JRC) of the EU Commission that was released in August 2012 titled "Unconventional Gas: Potential Energy Market Impacts in the European Union" in which the TRR in Europe were estimated to be in the range of 2–18 Tcm (JRC, 2012). There are several reasons for the significant uncertainty surrounding the global/regional estimates of URR:

- Rapid depletion of wells coupled with lack of experience makes it difficult to estimate future levels of production, even those from single wells, let alone those from whole basins and/or countries;
- Large variability in the characteristics of different resource plays;
- With the exceptions of Australia and the US, global exploration efforts have been modest;
- The high levels of production of shale gas (and CBM/tight gas) in the US may be due to multiple factors that do not necessarily pertain to other countries;
- Environmental concerns, since many wells will have to be drilled with enormous consumption of water and the injection of chemicals.

The authors of the JRC study (JRC, 2012) mentioned above concluded that:

- "Shale gas has the potential to strongly impact global gas markets but only under strongly optimistic assumptions about its production cost and reserves".
- "The best case scenario for shale gas development in Europe indicates that import dependence can be maintained at current level of around 60%".

In Europe, so-called 'fracking' (production method required to produce shale gas) has been banned in Bulgaria and France, whereas in Germany shale gas exploration has been allowed to date but only in North Rhine Westphalia and Lower Saxony and the regulators/authorities appear to be taking a cautious approach. In Poland, the TRR for shale gas has been revised downwards compared to previous estimates. In the UK, the Department of Energy and Climate Change recently announced that fracking can be utilised for the production of shale gas. It is generally believed that the production of shale gas in the EU will be led by Poland and the UK.

Facts – Unconventional gas	
Shale gas:	Shale gas refers to natural gas that is trapped within shale formations. Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas.
Tight gas:	Tight gas is gas that is trapped in impermeable rock and non-porous sandstone or limestone formations, typically at depths of more than 10 000 feet below the surface.
Coal Bed Methane (CBM):	CBM is a gas that is created during the formation of coal seams. It is an unconventional resource, as the methane is contained in the coal and does not migrate to other rock strata.

Figure 2.1. *Unconventional gas basins in Europe. Source: IEA (2012c).*

Increased import of LNG is another possibility for the European market. In North America (Canada and the US), more than 30 LNG plants are currently under development, with a combined capacity of more than 450 bcm, which corresponds to 136% of the global trade in LNG in 2011. About 20 of these plants are located in the US and have a combined capacity of 300 bcm (Chalmers fuel databases). As of December 2012, one plant has been granted a construction permit: the 24-bcm Cheniere Energy's Sabine Pass plant in Louisiana. The remaining plants are awaiting a political decision as to whether the US will allow exports of natural gas.

Regional assessment of modelled gas consumption

Assuming an abundance of global gas supply leading to competitive gas prices we examined what impact this might exert on the European power sector. On an aggregated level (EU-27, Switzerland and Norway), the growth in gas consumption in the power sector up to 2020 in the studied scenario, where a gas to coal price ratio of 2.0 is assumed, is modest at 8.3% (an increase from 181 bcm to 196 bcm) (for more on this, see Chapter 12). However, for some individual countries, the increase is more significant in both absolute and relative terms. The growth level after 2020 and up to 2030, at which point peak consumption will have been reached, is greater on an aggregated level, representing an increase from 196 bcm to 305 bcm. Since the largest increase in gas consumption occurs between 2020 and 2030, it is difficult to analyse market impacts with regard to infrastructure and supply capabilities, whereby the latter refers to the combined effect of indigenous production, storage withdrawal capacity, and import capacity/contracted gas[1]. After 2030, consumption starts to decline precipitously, from 305 bcm in 2030 to 245 bcm in 2044 before it starts rising again reaching 280 bcm in 2050. As take-or-pay contracts usually allow for a 15% decline relative to contracted quantity and since most importers purchase an increasing share of their total imports in the form of spot market gas, this decline in gas consumption post-2030 should not represent a problem – seen isolated, i.e. the risk of oversupply due to contracted gas should be relatively modest. As mentioned above, for some individual countries, there is a significant increase in the modelled gas consumption levels in the power sector already up to Year 2020 (Table 2.1).

Table 2.1. Real (for Year 2010) versus modelled (for Year 2020) gas consumption levels in the power sector for selected countries

	Real Cons 2010, bcm	Model results 2020, bcm
Cyprus	0.0	1.0
Czech R	0.5	1.6
Finland	2.6	5.3
Greece	2.5	5.2
Hungary	3.3	5.6
Malta	0.0	0.4
Poland	1.3	8.2
Slovakia	0.7	2.4
Sweden	0.8	1.6

[1] Current import capacity however far exceeds import requirements, with an annual capacity of 660 bcm of gas, which does not include the South Stream and the Trans-Adriatic Pipeline, as compared with 310 bcm of imported gas in 2011 (IEA, 2013).

The increase in gas consumption projected for Poland is particularly interesting given that: 1) many gas plants are currently under development in Poland; and 2) Poland is building an LNG import terminal, primarily to reduce their dependence on gas imports from Russia.

German close up

In this section, we present an assessment of German gas consumption for the studied scenario (see Chapter 12). According to the IEA (2012d), natural gas consumption for power generation reached 21 bcm in 2010, corresponding to 23% of total gas consumption (90 bcm). According to the above-mentioned modelling results, gas consumption is considerably below the current consumption level, which will not be reached until 2018–2019 (this is the case because the ELIN model derives the least cost mix of fuels/ technologies)[2]. Thereafter, however, consumption increases very rapidly, from 19 bcm in 2018 to a peak of 72 bcm in 2030.

In the period 2000–2010, total gas consumption in Germany has grown by 0.6% per annum (p.a.). Sector-wise and over the same time-period, consumption has grown by 0.7% p.a. for both industry and private households, while it has decreased by 0.4% p.a. in the commercial, trade, and services sectors. However, in the power sector, gas consumption has grown on average by 3.9% p.a. in the period 2000–2010, obscuring the fact that the gas consumption level in 2010 was actually lower than the peak level reached in 2008 and that consumption declined further in 2011. The economic recession led to a significant decline in consumption in 2009, which was not recovered in 2010, while during most of 2011, gas has not been competitive with coal. Nevertheless, we assume (these assumptions are illustrated in Figure 2.2.) that:

1) Natural gas consumption in the power sector is maintained at the current level up to Year 2019, and thereafter develops as envisaged in the analysed scenario (i.e., as obtained from the modelling); and

2) Natural gas consumption in all other sectors continues to increase by 0.6% p.a. from Year 2010 onwards.

[2] The ELIN model is used widely throughout the Pathways research programme and described in more detail in the *Methods* main section of this book.

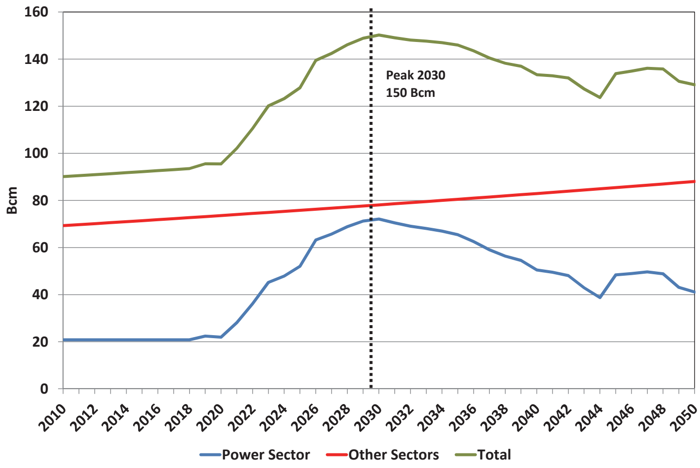

Figure 2.2. *Assumptions made for natural gas consumption levels (for the power generation sector, the values shown after Year 2019 are those obtained from the modelling exercise assuming a gas-coal price ratio of 2.0).*

Figure 2.2 implies an increase in total gas consumption of 67%, with most of this increase occurring between 2020 and 2030.

The current capability of Germany to supply gas can be derived by summing the import capacity, domestic production level, and the maximum withdrawal capacity from storage reservoirs. Supply capability as of the end of Year 2012 is shown in Table 2.2. Note however that indigenous production and storage withdrawal capacity refers to the end of Year 2011, while only the first string of the North Stream pipeline is included in pipeline import capacity. Also shown in Table 2.2 is the average daily consumption, as well as the “apparent peak consumption”, whereby the latter refers to peak monthly consumption between 2007 and 2011, which is divided by 30 to derive the daily consumption level.

Table 2.2: Ability to supply natural gas in Germany as of the end of Year 2012 as obtained from the analysis in this book

	Conversion Value	Capacity	Capacity	Capacity
	PJ/bcm	GWh/d	bcm/d	bcm/yr 100% UF
Import capacity pipelines	37.17	6729.2	0.6517	237.9
Import capacity LNG	0	0.0	0.0000	0.0
Indigenous production 2011			0.0353	12.9
Storage withdrawal capacity[1]			0.5209	
Total		**6729.2**	**1.2080**	**250.8**
Real average Cons 2010			**0.2468**	**90.1**
Modelled average Cons 2030			**0.4115**	**150.2**
Apparent peak consumption[2]			0.4135	

[1] *Total storage capacity as of end 2011 which is sufficient to cover 39 days of max withdrawal.*
UF: Utilisation Factor

[2] *The peak monthly consumption in the period 2007–2011, divided by 30 days to yield the daily consumption level.*

Sources: *Import capacity PL: ENTSOG's Capacity Map and corresponding excel-sheet, version June 2012.*
Indigenous production: Landesamt für Bergbau, Energie und Geologie (LBEG).
Storage withdrawal capacity: Landesamt für Bergbau, Energie und Geologie (LBEG).

As is evident from Table 2.2, Germany currently has a daily supply capacity of 1.21 bcm, which may be compared with an average consumption of 0.25 bcm in 2010 and modelled level of consumption of 0.41 bcm in 2030. To this it should be added that both storage capacity and import capacity will increase in the next few years, whereas domestic production will continue to decline, albeit slowly. Furthermore, average consumption is of course not relevant, as natural gas consumption tends to vary significantly over the course of a year, given that a large fraction of the gas is consumed for heating purposes. Peak consumption in Germany normally occurs in the December to January period and based on data for the end of Year 2011, the peak monthly consumption of 12.4 bcm occurred in December 2010, which gives an average daily consumption of 0.41 bcm. This again indicates a sufficient reserve capacity as of the end of 2011/2012. Usually, the ratio of peak monthly consumption to minimum monthly consumption within a specified year ranges from 2 to 3. However, in December 2010, peak consumption was 3.3-times higher than the lowest consumption level noted for that same year.

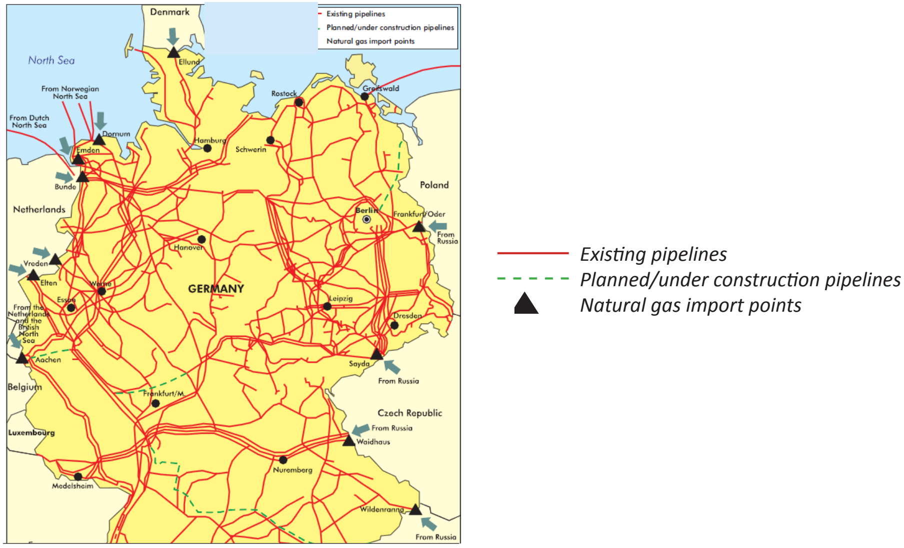

Figure 2.3. *Existing and planned German gas grid. Source: IEA (2012d).*

Finally, with regard to gas plants and siting issues: the modelling provides that between 2018 and 2030, some 50 GW in new gas based capacity is being installed. This by no means represents a dramatic increase, since the German gas grid is already very well developed, as can be seen from Figure 2.3 (data taken from IEA, 2012d). The gas-based capacity additions given by the modelling are therefore not considered to be a potential problem.

Conclusions

Based on a thorough assessment of the natural gas market (while not all of the details are explicitly outlined above, we have built upon previous work and discussions, see Kjärstad et al, 2014) the following conclusions can be drawn:

1) There exist significant global resources of both conventional and unconventional gas.
2) Estimates of Technically and Ultimately Recoverable Resources of unconventional gas are uncertain for all regions of the world, and to some extent also for the US. In the latter case, this is evidenced by, for instance, the EIA's substantial downward revision of technically recoverable resources in 2012 (see above).
3) Prospects for future production of unconventional gas in Europe are uncertain, due not only to the uncertainties related to the recoverable resource base, but also to issues linked to production ability, environmental concerns, and supply infrastructure.
4) The prospects for the production of unconventional gas within Europe appear to be greatest in Poland and the UK, possibly reaching levels that have significance for their respective national markets, albeit not until the latter part of this decade at the earliest.

5) Production of conventional gas in EU is set to decline. In Norway, new resources will have to be discovered and proven up to avoid a major decline in production before 2020.
6) There will be no "abundancy of natural gas" on global markets until late in this decade at the earliest, if at all.
7) It is concluded from the present work that US exports of natural gas will not significantly affect global markets with respect to gas price levels until late this decade at the earliest, if at all. This seems likely given that few gas export plants will be up and running before 2020, assuming that the US federal government allows such exports. Furthermore, significant exports of gas from the US are likely to lead to increases in gas prices in the US, thereby adversely affecting the competitiveness of US gas on international markets.
8) Increases in the investment costs for LNG may defer several large-scale projects, which in turn could have an impact on the global supply after 2020.
9) US gas prices will increase from their current levels as a consequence of:
    a) Rising demand, foremost in the power sector, but also in industry and possibly in the transport sector (albeit from a low baseline consumption);
    b) Producers switching to more liquid-rich plays;
    c) Increased exports of gas (if such are allowed).
10) US gas is not likely to be more competitive than gas from other suppliers in European markets.
11) We expect European gas prices to be increasingly de-linked from oil prices, while spot trading is expected to gain importance, i.e., increase in relation to volume.

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Resources

3 CO_2 transport and storage – crucial element for future CCS

The Chalmers database of CO_2 sinks has recently been updated in line with new assessments of the storage potential of CO_2 in Europe. Storage capacity is unevenly spread among the European countries, and a major share of the capacity is in aquifers. The development of CCS in a wider European context has been investigated in collaboration with the Joint Research Centre (JRC) of the European Commission. This work links the annual CO_2 flow by country, as provided by the Chalmers ELIN model, to a model developed by JRC that optimises a bulk CO_2 pipeline network. Finally, we use the Chalmers databases on CO_2 sources and sinks to develop a detailed CCS network with collection and distribution pipelines. The results indicate a doubling in investment cost when moving from onshore carbon storage to offshore storage. In addition, the results indicate that offshore storage is needed to facilitate large-scale CCS in Europe. As much of the estimated offshore storage capacity is concentrated in north-western Europe, CO_2 transport solutions for the Nordic region have been investigated. We propose that the Kattegat-Skagerrak area offers the best opportunities for a Nordic CCS system, and that transfer by ship is the most appropriate transport mode for captured carbon in the Nordic region, at least in a ramp-up phase. Furthermore, it is concluded that reservoir injection capacity will have a decisive effect on any CCS infrastructure system, although this parameter is not known for most of the aquifer storage sites. Moreover, in most instances, drilling will be required to determine accurately the injection capacity. Since drilling offshore is costly, the question arises as to which stakeholder will be willing to take on board this risk.

Updated storage potential

As knowledge is accumulated in relation to CO_2 storage reservoirs, the estimates of storage potentials change. A recent update of the theoretical storage potential is presented in Figure 3.1 (EU Geocapacity, 2009; Knopf et al., 2010; Donda et al., 2010, Tarkowski, 2008), in which the estimated storage potential is specified for each reservoir category and region. However, there are large uncertainties regarding the actual storage capacity, with preliminary estimates of the total storage capacity in the EU in the range of 122–234 Gt CO_2. In addition, Norway is estimated to have a total storage potential of approximately 86 Gt CO_2 (NPD, 2011; NPD, 2012; NPD, 2013). As shown in the figure, the storage potential is unevenly distributed among the European countries, which suggests that international cooperation is a prerequisite for large-scale CCS. From the figure it is also clear that most of the potential lies with the aquifers, whereas gas, oil, and coal fields represent relatively small fractions of the total potential. Of the gas, oil, and coal fields, gas fields have the largest potential. The advantages of gas and oil fields with regard to CO_2 storage are that: 1) a large body of data is available that can be used to make accurate decisions as to injection and storage capacity; and 2) the seal above the reservoir has remained intact over millions of years.

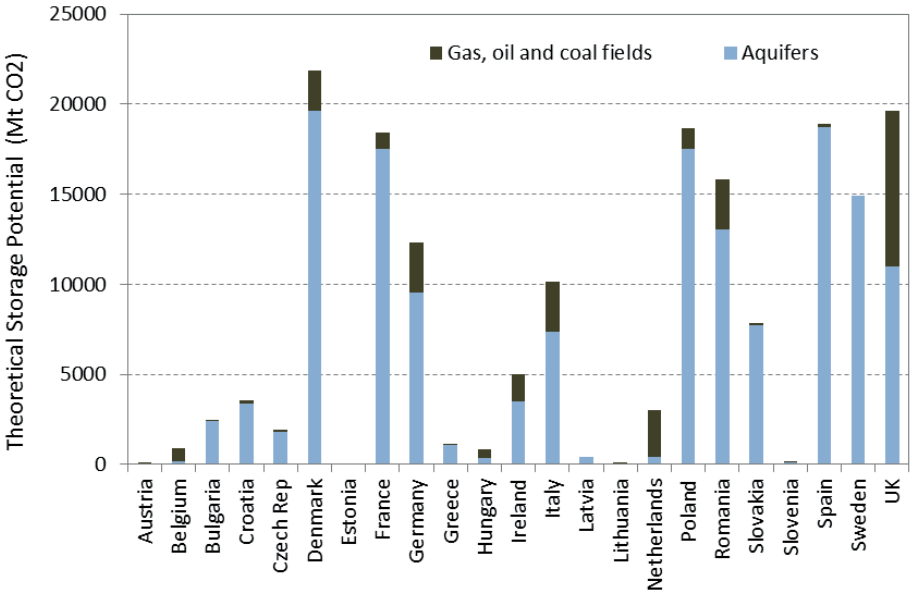


Figure 3.1. *Estimated theoretical storage potentials in EU countries; data updated in December 2013.*

Modelling large-scale CCS development in Europe – linking techno-economic modelling to transport infrastructure

The joint project with the European Commissions JRC (Kjärstad et al., 2012a) can be divided into three distinct parts;

1) The Chalmers ELIN model provides annual CO_2 flow data by fuel and country as part of modelling Europe's electricity sector through the targeting of strict CO_2 emission reduction targets, significant penetration of renewables, and the availability of CCS as a competitive CO_2 mitigation option from Year 2020 (cf. the Regional Policy and Climate Market scenarios as further described in Chapter 10).

2) The JRC develops cost-optimised bulk pipeline system for Europe based on the annual flow data by fuel and country, as provided by the ELIN model.

3) Chalmers develops a detailed CCS network by integrating ELIN's CO_2 flow data, JRC's bulk pipeline system, and Chalmers databases of CO_2 sources and sinks.

Offshore storage will add significantly to cost

This section focuses on the second and third parts of the project outlined above. Figure 3.2 shows JRC's bulk pipeline system in 2050, which is based on the Regional Policy scenario, with Figures 3.2a and b illustrating cases in which storage in onshore aquifers is allowed and is not allowed, respectively. Onshore storage is allowed in oil and gas fields in both cases, since these have proved to be closed reservoirs. The system is based on the clustering of sources and sinks (in the figure, red circles denote clusters of sources, blue circles denote clusters of aquifers, and green circles denote clusters of oil/gas fields), with JRC applying the conservative storage capacity values derived in the GeoCapacity project (GeoCapacity, 2009). In total, 15.2 $GtCO_2$ is transported to storage sites in the period 2020–2050, as envisaged by the Regional Policy scenario.

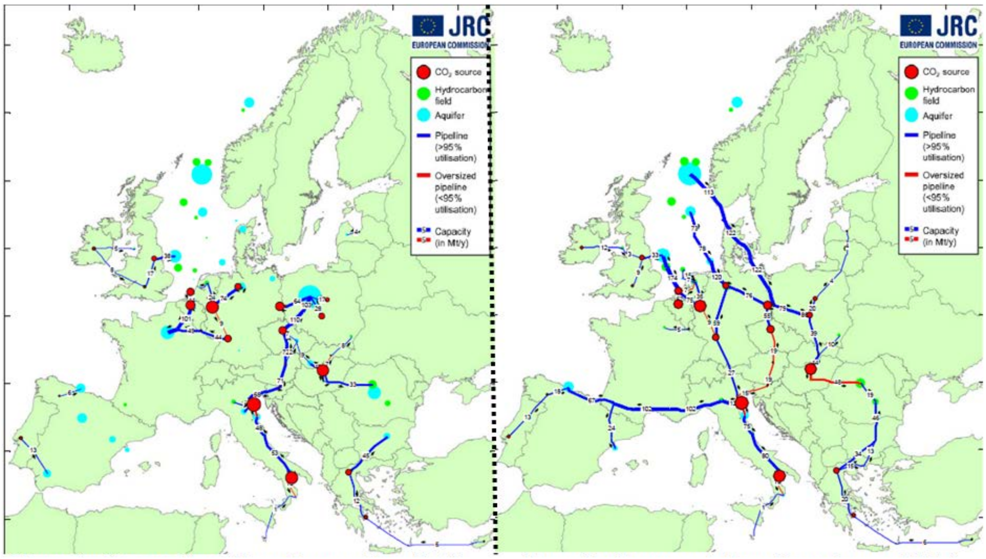


***Figure 3.2a**. Storage allowed in onshore aquifers. Total investments € 14.0 bl, total network length 10 430 km.*

***Figure 3.2b**. Storage <u>not</u> allowed in onshore aqf. Total investments € 29.1 bl, total network length 15 200 km.*

Source: Kjärstad et al. (2012b)

The network gets 46% longer while investments more than double when the system is forced to store large amounts of CO_2 offshore (see Figure text).

Designing a detailed network requires accurate geographical information

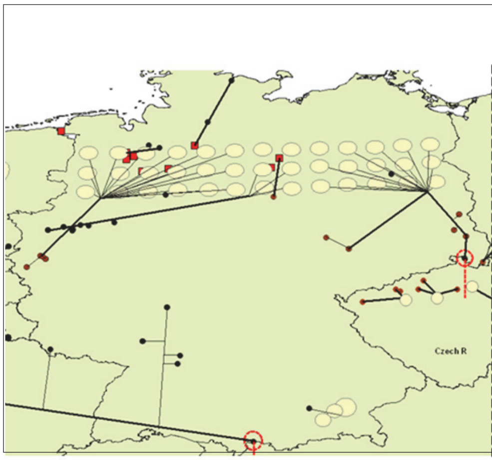
Part 3 of the joint project, which is work in progress, combines the information shown in Figure 3.2 with the Chalmers databases on power plants and CO_2 storage sites to design a detailed collection and distribution system. The geographical distribution of CCS plants over time is generated by applying the information provided by the ELIN Regional Policy scenario to replace existing plants according to plant age. Detailed data regarding the storage sites in Germany, Italy and Poland, more detailed data are found in Knopf, et al. (2010), Donda et al., (2010) and Tarkowski (2008). Figure 3.3a shows how Chalmers initially envisioned the distribution of aquifers in Germany based on communications with Vattenfall and the German Bundesamt für Geowissenschaften und Rohstoffe (BGR), while Figure 3.3b shows the distribution that was subsequently proposed by Greenpeace based on work performed by BGR (Knopf, et al., 2010; Greenpeace, 2011). The black dots and lines indicate CCS plants and CO_2 pipelines, respectively, while the red squares indicate large gas fields, and the light-yellow circles denote aquifers (note that the CCS systems depicted in Figure 3.3b utilise slightly more gas fields for storage than the systems depicted in Figure 3.3a).

In the transport schemes illustrated in Figure 3.3a, each German aquifer was assumed to have a storage capacity of 100 $MtCO_2$, with a combined storage capacity that corresponds to the lower estimate provided by BGR (6.3 $GtCO_2$). In Figure 3.3b, the storage capacities of the aquifers have been designated individually based on data provided by BGR and Greenpeace and scaled-down by a factor of 0.48 to yield the same total conservative storage capacity for Germany as a whole, i.e., 6.3 $GtCO_2$. Overall, BGR and Greenpeace published data for in total 408 aquifers with individual storage capacities that ranged from <1 Mt CO_2 to 330 Mt CO_2.

The main difference between the two systems depicted in Figure 3.3a and b is that in the latter it was assumed that a minimum injection period of 45 years was required to fill an aquifer, and that only aquifers with a storage capacity of ≥45 Mt CO_2 were utilised as storage sites, i.e., those sites with an annual injection capacity of at least 1 Mt CO_2. In total, 37 aquifers with a combined storage capacity of 3.7 Gt CO_2 were used as storage sites in the systems depicted in Figure 3.3b. The two CCS systems depicted in Figure 3.3 transport 3.5 Gt CO_2 between Year 2020 and Year 2050. However, owing to the lower anticipated injection capacities of the systems shown in Figure 3.3b, more CO_2 has to be exported to the French and Polish storage sites.

The collection and distribution network will entail significant additional costs

Although the distributions of storage sites and, more importantly, the storage and injection capacities differ between the systems depicted in Figure 3.3, these differences have a limited effect on system costs. While the total pipeline length reaches 5 116 km in the system shown in Figure 3.3a, the length of the system in Figure 3.3b is 5 025 km. Investment costs are reduced by €0.7 billion in the system in Figure 3.3b, from €10.3 billion (system Figure 3.3a) to €9.6 billion, while the specific transport cost decreased from €5.98/tCO_2 to €5.36/tCO_2 respectively. However, the detailed German collection and distribution system shown in Figure 3.3b will alone require investments corresponding to two thirds of the entire European bulk system as provided by JRC, i.e. the system shown in Figure 3.2a.



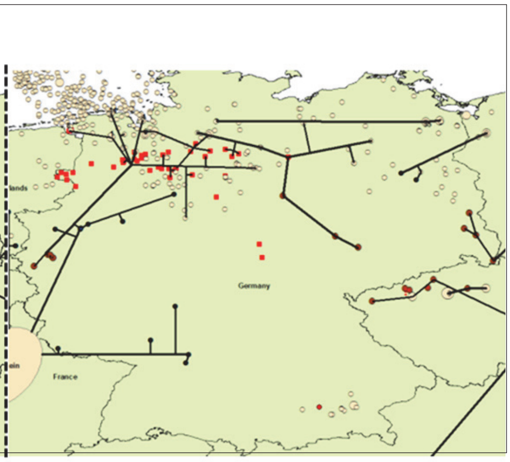


Figure 3.3a. *Initially envisioned distribution of aquifers in Germany*

Figure 3.3b. *Distribution of aquifers as given by Greenpeace and BGR (Knopf et al., 2012; Greenpeace, 2011)*

Large-scale CCS in EU is likely to require offshore storage

A second factor that strongly affects the system designed in Part 3 of the project (Figure 3.3b) is the proposal by JRC to apply an upper limit to the annual injection capacity in an aquifer. This parameter is highly specific for reservoirs and is usually not defined. However, after consultations with leading geologists, it was decided to apply a minimum injection period of 45 years, i.e., the storage capacity divided by 45 yields the upper limit of the annual injection capacity. This would mean that the aquifers in many countries (e.g. Belgium, Germany and Italy) are not sufficient to handle the national injection requirements. Hence, large amounts of CO_2 would have to be exported from, these countries, to large aquifers in the Paris basin and in Poland. The feasibility of such export is dubious for the following reasons; a) the significant opposition to onshore storage experienced in other parts of Europe; b) the risk of domestic opposition in France and Poland to the storage of large volumes of CO_2 generated abroad and; c) the fact that the applied storage capacity and annual injection capacity of French aquifers correspond to the conservative theoretical value given by the GeoCapacity project, which in itself is subject to significant uncertainties. Therefore, if France and Poland for some reason cannot (or are unwilling to) store large amounts of 'foreign' CO_2, offshore storage appears to be the only remaining option for large-scale CCS in the EU, at least for the large volumes and the geographical distribution of the same that have been discussed in this chapter.

Recommendations for CO_2 transport solutions in the Nordic region

In cooperation with the Nordic CCS Competence Centre (NORDICCS), several CO_2 transport solutions for the Nordic region have been investigated. The aims of this work were: 1) to recommend transport solutions for CO_2 sources in the Nordic region, herein defined as the most cost efficient transport mode for the selected CCS cases in NORDICCS: and 2) to analyse the potential for establishing CO_2 clusters by means of a transportation network around the selected CCS cases, to reduce transportation costs. Based on a comparison of the costs of pipeline transport and ship transport, it is concluded that for the majority of the selected cases, as well as for most of the emission sources in the region movement by shipping will be the most cost-efficient transport mode for each source individually. It is also concluded that ship transport is the most appropriate mode for most of the potential clusters in the region during a ramp-up phase. This is closely related to the underutilisation of pipelines and risk taking in connection with underutilised pipelines. For distances of <100 km and volumes <1 Mtpa, e.g., corresponding to a typical collection system that comprises multiple coastal sources, it has been calculated that an onshore pipeline in most cases will be the most cost-efficient transport solution. More generally, it can be stated that that the break-even distance where ship transport becomes more cost-efficient than pipeline transport increases as the volume of gas increases. An obvious but nonetheless important conclusion is that constrained storage capability has a profound impact on the design and cost of a CO_2 transport system. Finally, it is concluded that in the Nordic region, the Kattegat-Skagerrak area probably offers the best opportunities for a Nordic CCS system, possibly driven initially by CO_2 enhenced oil recovery, which may require a start-up already in 2020.

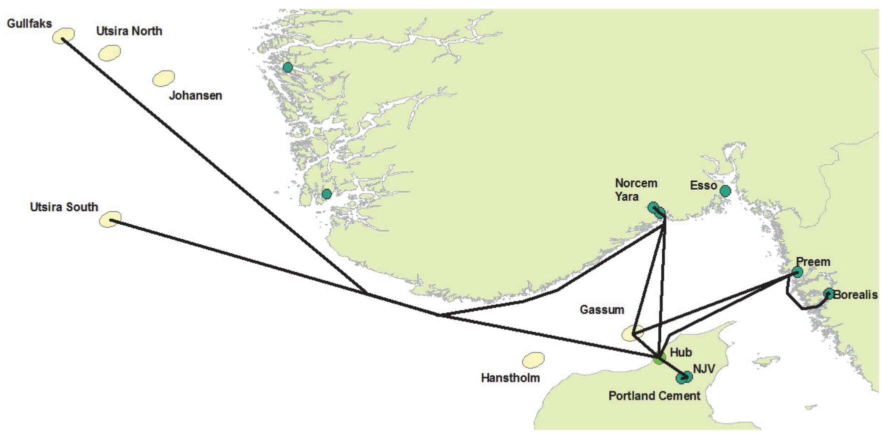


Figure 3.3. *Modelled transport systems in the Skagerrak region either directly to the Gassum formation or via hub northwest Jutland to Utsira and Gullfaks.*

Source: Kjärstad et al. (2014)

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4 Bioenergy: increasing use and emerging governance

The use of biomass for energy production is increasing in response to policies that are designed to address concerns about climate change and energy security. Many studies that have investigated pathways towards ambitious climate targets find that biomass demand for energy may increase more than 10-fold in the coming decades. The strategic importance of bioenergy is expected to vary with geographical location, and prioritisation of bioenergy options will be dictated by policy objectives, as well as the development of competing energy technologies. Governance (e.g. legislation, best management guidelines, trade standards) is essential, since the deployment of bioenergy involves dealing with a range of environmental, social and economic objectives that are not always fully compatible with each other. Bioenergy governance currently faces various challenges, including the heterogeneity of governance mechanisms and disagreements surrounding the suitability of different methodological approaches to evaluating bioenergy systems.

Status and expectations with respect to biomass use for energy

There has been a rapid increase in so-called 'modern bioenergy use' in response to policies that have been put in place to improve energy security and mitigate climate change. In many countries, the promotion of bioenergy is also considered as a driver of rural development, with capacities to improve energy access, increase employment, and stimulate positive developments in agriculture and forestry. At present, modern bioenergy use primarily involves: 1) the burning of municipal organic waste, straw, and wood and forest industry residues to yield heat and electricity; 2) anaerobic digestion of organic waste to produce biogas; and 3) the use of conventional agriculture crops, such as cereals, oil seeds, and sugar crops, to produce biofuels.

The technologies used for converting biomass to fuels and other products are being developing into sophisticated processes, while new plants and biomass production systems offer a broadened resource base. In forestry, advances with respect to planting, silvicultural treatments, and biomass extraction, support an increasing harvest from forests. In agriculture, residue extraction and the cultivation of perennial grasses and trees in short rotation periods (in both coppice and single-stem plantations) represent new feedstock supply options, as well as possibilities for farmers to diversify their land use so as to improve both the efficiency of resource use and revenues.

Currently, 10–15 EJ per year of biomass is used globally for modern bioenergy purposes, and many forward-looking studies predict that the demand for bioenergy will increase considerably. Figure 4.1 shows a magnitude comparison of biomass outputs in forestry and agriculture with prospective biomass demands for energy (see the figure caption for a more detailed description). It is clear the biomass extraction in agriculture and forestry will have to increase substantially in order to provide the feedstock for a bioenergy sector that is sufficiently large to make a significant contribution to the future energy supply. Chapter 5 considers the prospects for meeting high future demands for bioenergy, and Chapter 6 presents an overview of studies that have provided estimates of the global and European potentials for bioenergy supply.

In addition to indicating the magnitude of the demand for biomass, energy system modelling gives insights into the strategic value of biomass for specific energy applications and how this value depends on the development of other energy technologies. For example, access to biomass may be crucial for reducing GHG emissions in the road transport and aviation sectors due to difficulties in moving away from carbon-based fuels. In contrast, electricity generation can be decoupled from GHG emissions by using options other than those that rely on biomass, assuming that these develop into cost-effective alternatives.

The strategic importance of bioenergy can be expected to vary with geographical location. The notion that countries with large resources of biomass should limit their own use to some ”fair” per capita level that could be achieved globally, ignores the fact that also other non-fossil energy resources are unevenly distributed around the world. Some countries with limited resources of biomass may, for instance, have large areas that are suitable for solar power installations. Energy system modelling (IPCC, 2011) indicates that cost-efficient mitigation of climate change will involve not only significant international trade in energy products, but also regional differences in energy system development, which reflect the heterogeneous pattern of resources.

Definition of governance

Governance is the sum of the many ways (laws, norms, power, language) that actors and public/private institutions manage common affairs. It is a continuing process through which diverging interests may be accommodated and cooperative action may be taken. In this chapter we refer to governance of bioenergy as governance concerned with promoting positive effects of relevant production or development processes and avoiding/mitigating their negative impacts, considering all three dimensions of sustainability. The structure and spatial scale of bioenergy supply chains range from simple and local to complex and international, challenging the capacity of nation-state institutions to govern activities beyond their borders and jurisdiction. Recent years there have been many initiatives to develop voluntary sustainability standards and certification schemes, and also binding regulations such as those associated with EU Renewable Energy Directive. These are not sufficient to achieve sustainable bioenergy systems without additional governance mechanisms (e.g. local or state regulations or international trade standards) with which management must comply. Bioenergy supply chains therefore often pass several layers of governance which must work together to ensure the sustainability of bioenergy products sold in the marketplace.

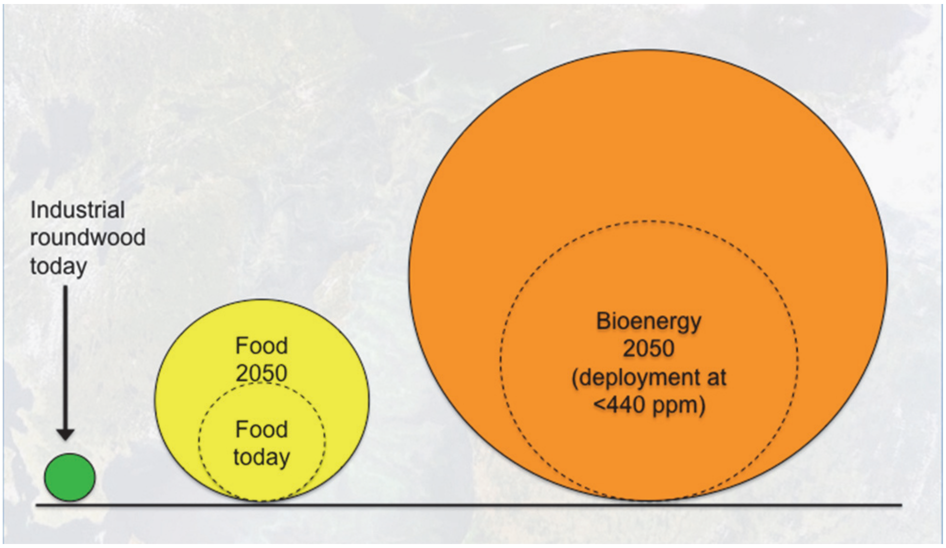

Figure 4.1. Comparison of the food and agriculture sectors with the prospective bioenergy sector. The energy content of today's global industrial roundwood production is about 15–20 EJ per year, and the global harvest of major crops (cereals, oil crops, sugar crops, roots, tubers and pulses) corresponds to about 60 EJ per year (FAO, 2011). The large orange circles show the range (25th and 75th percentiles) in biomass demand for energy, as given in a recent review by the IPCC of 164 long-term energy scenarios to meet concentration targets of <440 ppm CO_2eq (corresponding to 118– 190 EJ per year of primary biomass). Source: IPCC (2011).

Export of Swedish biomass to substitute for coal use abroad may today yield higher savings in GHG emissions than the domestic use of this resource, but the longer-term climate benefit of export versus domestic use is less clear. Countries that invest in energy technologies that exploit abundant domestic resources can create benefits for other countries in the longer term. For example, the current development of Swedish biofuel production capacity may generate greater benefits for the climate in the longer term (by accelerating the development and global deployment of low-GHG transport systems) than would be derived from a strategy to maximise near-term GHG savings through the export of biomass for coal displacement.

Governance of bioenergy

The growing demand for biomass means that there will be increasing competition for land, water, and other production factors, which may result in the over-exploitation and degradation of resources. As the use of bioenergy has increased, there has been an increase in the number of reports expressing concern about the possible negative impacts of bioenergy. Bioenergy feedstock production is the part of the bioenergy supply chain that has received most attention in the debate that has taken place in recent years. Much attention has been focussed on the possible consequences of land-use change (LUC), especially deforestation to make place for croplands, which can entail biodiversity losses, GHG emissions, and the degradation of soils and water bodies. Sustainability concerns relating to feedstock supply systems also include direct and indirect social and economic aspects, including land-use conflicts, human rights violations, and food security impacts. As it is clear that bioenergy systems can have both positive and negative consequences for sustainability, the deployment of such systems needs to balance a range of environmental, social, and economic objectives, which are not always mutually compatible. It is generally concluded that the consequences of bioenergy implementation are determined by the technology used, the location, scale and pace of implementation, and the business models and practices that are adopted. The widely diverging views expressed in the debate about bioenergy and sustainability are a reflection of the different real-world experiences with bioenergy implementation, as well as differences in opinions as to which impacts, e.g. on feedstock production and LUC, are acceptable.

Given the debate about bioenergy and sustainability that has raged in recent years, it is understandable that the policy makers who establish incentives or targets to promote bioenergy are concerned; society expects that risks are properly considered and that new system designs mitigate risks and alleviate rather than exacerbate land-use impacts. Therefore, bioenergy supply chains currently have to pass several layers of governance, including both emerging governance mechanisms that specifically address bioenergy (e.g., bioenergy sustainability standards and certification systems) and existing regulations for agriculture and forestry, such as local or state regulations, best-management practices, and international trade standards (Figure 4.2).

Ideally, the different governance mechanisms should complement each other and effectively ensure the sustainability of bioenergy sold in the marketplace. However, studies show that bioenergy governance currently presents challenges associated with the heterogeneity of governance mechanisms (Englund et al., 2012; Junginger et al., 2011; O'Connell et al., 2009; Stupak et al., 2011; van Dam et al., 2010), and actors point to barriers, such as high administrative complexity, high costs, and small market advantages (Pelkmans et al. 2013a; Goovaerts et al., 2013).

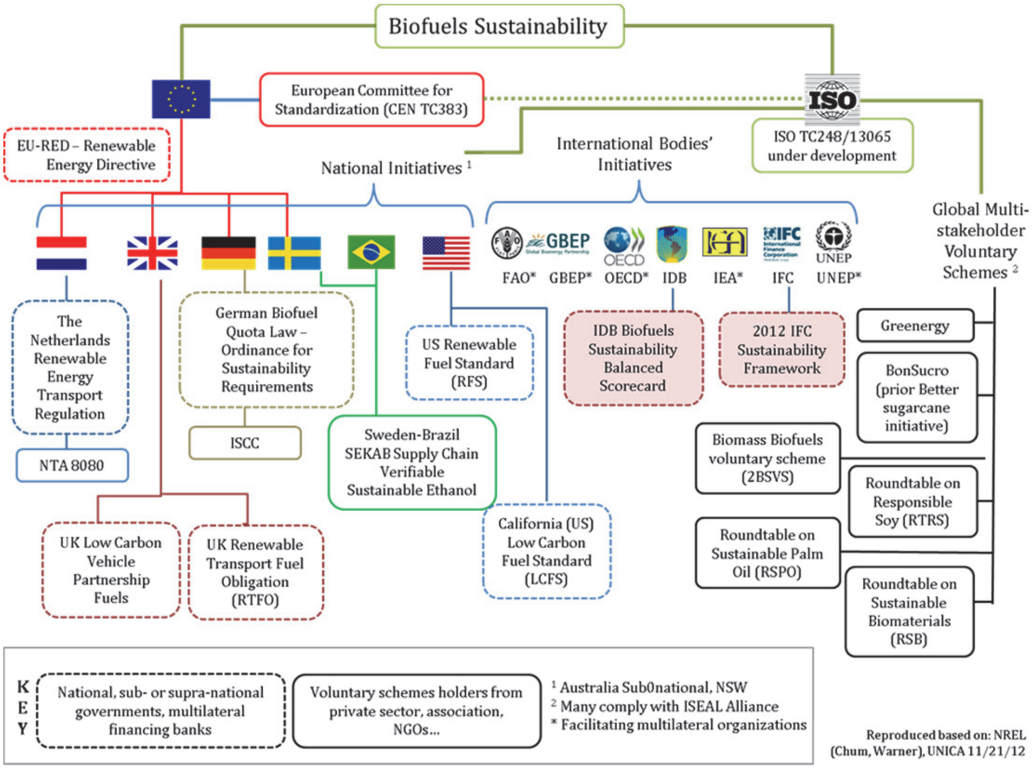

Figure 4.2. *Schematic of government-led initiatives (in dashed-line boxes) and of sustainability standards in relation to liquid biofuels that have been developed over time by a variety of entities (full-line boxes). Many of these initiatives are organised through voluntary schemes by multiple stakeholders. Others, not displayed here, exist specifically for forestry and agriculture. Scorecards are also used to provide check-lists of project submissions for financing by multilateral organisations.*

The proliferation of governance mechanisms has caused confusion among actors and has raised questions about the adequacy of systems in place and how to develop systems that are effective and cost-efficient (Pelkmans et al., 2013a; Buytaert et al., 2011; Magar et al., 2011; van Dam et al., 2011). The actors in bioenergy supply chains may need to comply with different standards to maintain market access and to comply with legislative mandates. Consumers who try to make environmentally conscious purchasing decisions and regulatory agencies and governments that are involved in enforcing sustainability standards may find it difficult to manage a wide range of systems that use different criteria/indicators.

The fact that there is disagreement about the suitability of different methodology approaches to evaluate bioenergy systems adds a further layer of complexity to the governance of bioenergy. Decisions on methodological approaches can influence strongly the evaluation outcome, which means that they affect the eligibilities of bioenergy systems in different markets. As long as the evaluation frameworks continue to be debated, actors cannot judge with confidence whether certain bioenergy systems will be eligible in the intended markets. This is further discussed in Chapter 7.

In summary, the emerging bioenergy governance presents many challenges but is important for ensuring that the rapidly expanding bioenergy industry brings benefits and that negative effects are avoided or mitigated. The heterogeneity of bioenergy systems require that governance mechanisms system specific, but harmonization and cross-compliance should be sought for when possible. There also needs to be a balance between comprehensiveness and stringency on the one hand and feasibility from a producer perspective on the other hand.

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5 Biomass for energy: what determines resource availability?

Estimates of the supply potentials for different bioenergy resource categories and regions vary widely because many of the determining factors are inherently uncertain. Biomass from dedicated plantations is often regarded as the largest – but also the most uncertain – resource. The size of this resource depends on many factors, not least the demand for animal food products and the land claims associated with meat and dairy production. While studies commonly adopt food-first principles and introduce restrictions to estimate so-called "sustainable" levels of bioenergy supply, no level of biomass supply comes with a guarantee of sustainability. The consequences of bioenergy expansion are to a large degree related to the deployment strategies and the environmental, socioeconomic, and institutional situations where the deployment takes place. Further research is needed into the influences of the various governance mechanisms on resource availability. In this chapter we present ranges for estimates of global biomass supply potentials and discuss decisive factors.

Estimates of the potentials for bioenergy supply for different resource categories and regions vary widely due to differences in the approaches used to weigh important factors, which in themselves are uncertain (see for example, Batidzirai et al., 2012; Beringer et al., 2011; Dornburg et al., 2010; Erb et al., 2012; Haberl et al., 2011; Wirsenius et al., 2010). Among other parameters, projected trajectories for population and economic and technological developments, as well as the evolution of consumer behaviour (e.g., regarding food waste, material recycling, diet) will determine future demands on biomass for food and other products, which translate into demands for land, water, and other resources. Specifically, the bioenergy resource potential is dependent upon: (i) the characteristics of the food and forestry sectors (e.g., crop yields, water-use efficiency, livestock-feeding efficiency, adaptation to specific growing conditions), which are influenced by land use, climate change, land tenure, and regulations; (ii) the competition between and complementarities of different forms of land use; (iii) social and political decisions regarding trade-offs in environmental and socioeconomic effects; and (iv) trade patterns, logistics that link supply and demand, and technological developments in feedstock conversion (notably, to facilitate biofuel production based on lignocellulosic resources).

The bioenergy resource categories that are commonly assessed include residues and waste in the agriculture and forestry sectors, organic post-consumption waste, and dedicated biomass plantations, which are often assessed as the largest, albeit most uncertain, resource (see Table 5.1 and Chapter 6 for an overview of the global and European estimates of bioenergy potential). Studies that assess the potential of dedicated biomass plantations commonly apply a "food/fibre-first" principle, with the objective to quantify biomass resource potentials under the condition that meeting the global requirements for food and conventional forestry products (e.g., sawn wood and paper) is given priority. They also often set (more or less restrictive) limits on access to lands that are not already being used by humans. These limits may reflect biophysical restrictions, such as water availability, and other restrictions, such as GHG balances associated with land conversion, biodiversity protection and nature conservation requirements (see for example, Beringer et al., 2011; Chum et al., 2011; Erb et al., 2012).

Higher-end estimates of the potential for dedicated biomass plantations correspond to a future scenario in which improvements in land and biomass-use efficiency outpace the growth in food and fibre demands, with the consequence that large areas that were previously used for food production (both cropland and grazing land) become available for biomass plantations (Hoogwijk et al., 2005; Hoogwijk et al., 2009; Smeets et al., 2009). Not all of the assessments that give higher values for this resource category rely on shifts in diet or strong improvements in efficiency drastically reducing the land demands of the food sector. Scenarios with relatively low levels of population growth and very high levels of growth in agricultural productivity can also have strong potentials for biomass supply, despite trends towards more meat and dairy in diets.

Thus, besides the criteria that are used to set limits on access to land, modelling of future land-use productivity is critical, since it determines both the land requirements to meet given food and fibre demands and the biomass supply potential for lands deemed to be available for bioenergy. Different approaches are used to model future land-use productivity and while all of these approaches have their own merits and limitations, they jointly help to advance our understanding of the prospects for dedicated biomass plantations by: (i) showing the extent to which the future potential is influenced by various determinants; and (ii) identifying areas where technological advances are essential and where more research is needed. This was also the conclusion of the IPCC's special report on renewable energy sources and climate change mitigation (IPCC, 2011) which, beyond the issue of quantitative biomass supply, pointed out examples of how integrated and multifunctional land-use systems can support multiple environmental and socioeconomic objectives. In addition, that study proposed that investment in agricultural research, development, and deployment could improve the robustness of plant varieties for all applications and could result in considerable increases in land and water productivity, as well as conferring environmental and socioeconomic benefits.

IPCC (2011) found a wide range of estimates of the global technical resource potential (<50 EJ/yr to >1000 EJ/yr) and set forth potential deployment levels for Year 2050 at 100–300 EJ/yr. The Global Energy Assessment (GEA, 2012) study included a smaller selection of studies, and reported a lower global technical resource potential in Year 2050 (160–270 EJ/yr), while stressing stricter constraints related to possible competing land demands, problems posed by possible deforestation, and water availability. The deployment level for Year 2050 was in the range of 145–170 EJ/yr in the GEA study (Table 5.1. See also Chapter 6).

Table 5.1. Global biomass resource potentials in Year 2050 (IPCC (2011), values in black; GEA (2012), values in green)

Biomass resource category	Global resource potential in Year 2050 (EJ/yr)
Forest biomass: Residues and waste plus utilisation of the part of the sustainable harvest levels in forests that are judged as being available for wood extraction, which is greater than the projected biomass demand for producing other forest products.	0–110 19–35
Agriculture residues: Manure is given separately in parentheses and is not included in the agriculture residue potential; the number shown refers to the energy value of the manure; the energy in biogas that could be produced from the manure is about 25% of that value.	(5–50) 15–70 (39) 49
Dedicated biomass plantations	0–700 44–133
Organic wastes: Waste from households and restaurants, discarded wood products, such as paper and demolition wood, and waste waters that are suitable for anaerobic production of biogas.	5 to >50 11
Total potential	<50 to 1000 160–270

As noted, arriving at precise values for the future potential of the biomass resource is not possible, since it depends on a number of factors that are inherently uncertain and that will continue to make long-term potentials unclear. It has been proposed that biomass supply for energy should be restricted to a ”safe” or ”sustainable” level, implying that a sustainable bioenergy potential can be defined and quantified. However, as was concluded in IPCC (2011), the magnitude of the biomass resource potential depends on the priority assigned to bioenergy products over other products obtained from the land, notably food, fodder and materials such as sawn wood and paper, and on how much total biomass can be mobilised in agriculture and forestry. This in turn depends on natural factors and on how society understands and prioritises nature conservation and the protection of soils, water, and biodiversity, as well as on how agronomical and forestry practices are shaped to reflect these priorities.

In addition, the notion of determining a sustainable level of bioenergy supply assumes that impact risks increase more or less linearly with the total level of biomass harvest for energy. However, the consequences of bioenergy expansion are determined in large part by the deployment strategy and the environmental, socioeconomic, and institutional conditions where the deployment takes place. Bioenergy production also interacts in complex ways with food and fibre production, which makes the assessment of bioenergy impacts highly challenging. For example, while the present expansion of biofuels creates competition for some food and feed crops, the demand for biofuel feedstock stimulates investments into production capacity for these crops (as does crop demand for animal feeding). Larger production capacity can function as a buffer to mitigate food price increases associated with crop failures in important production regions. In general, demand for feedstocks from croplands provides incentives to maintain agricultural land in regions in which the alternative is active afforestation or land abandonment with gradual reversion to forests or other natural vegetation. However, the demand for bioenergy feedstock can also result in croplands being planted with fast-growing trees to provide bioenergy feedstock, which may entail slower reversal to food crop production when food prices are high.

It is important to note that studies that assess biomass resource potentials far into the future have limited relevance to discussions of the present-day consequences of bioenergy expansion. Assessments that start from food/fibre-first principles and set limits on resource availability should not be understood as providing guarantees that a certain level of biomass can be supplied for energy purposes without competing with food or fibre production, or without resulting in impacts on soil, water, and other resources. These assessments quantify the bioenergy that could be produced in a certain future year based on using resources that are defined as being available and not required to meet food and fibre demands, given a specified development in the world or in a region. However, they do not investigate how bioenergy expansion towards such a future level of production would or should interact with food and fibre production or how it affects resources and the environment.

Recent reports about negative environmental and socioeconomic impacts associated with bioenergy reveal that such negative impacts can occur already with low levels of bioenergy use (e.g., with just a few percent of the global agriculture land being used for bioenergy). At the same time, a wealth of studies point to examples of how the integration of bioenergy systems into agricultural and forest landscapes could improve land and water use efficiency and help to address concerns about the environmental impacts of present land use (Batidzirai et al., 2012; Baum et al., 2012; Berndes et al., 2004; Berndes et al., 2008; Börjesson & Berndes, 2006; Busch, 2012; Dimitriou et al., 2009, 2011; Dornburg et al., 2010; Garg et al., 2011; Gopalakrishnan et al., 2009; 2011a,b; 2012; Parish et al., 2012; Sparovek et al., 2007). Capturing the benefits of bioenergy requires that incentives are created that stimulate innovation with regard to land use, including new ways to integrate bioenergy feedstock production in the agricultural and forestry landscapes, so as to promote productivity improvements, local development, and sustainable land-use practices.

Relatively few studies have investigated how the future potential of bioenergy relies on the evolving system of bioenergy governance, including policies and regulations that directly (e.g., EU-RED) and indirectly influence the conditions for bioenergy. Examples of the latter include the Landfill Directive (1999/31/EC), which obliges Member States to reduce the amount of biodegradable municipal waste that they landfill to 35% of the Year 1995 levels by Year 2016 (for some countries, the deadline is Year 2020). This directive creates incentives for energy production from organic waste, e.g., anaerobic treatment to produce biogas and incineration to produce heat and power. Another example, the Water Framework Directive (2000/60/EC), influences the conditions for land use and can, for instance, create incentives for farmers to shift to growing perennial grasses and woody plants that are suitable as bioenergy feedstocks in areas where the cultivation of conventional annual food/feed crops has an impact on groundwater quality (see the Text box below). Chapter 7 presents an example of how the potential of bioenergy may be influenced by the evolving system of bioenergy governance.

In summary, the future biomass supply potential is uncertain since many of the determining factors are inherently uncertain. It can however be concluded that measures to keep down land requirement for food production are needed for reaching high biomass supply potentials, if large scale conversion of natural ecosystems is to be avoided. Diets and land use productivity, especially in grazing production, are critical. It is not possible to quantify ”safe” or ”sustainable” biomass supply potentials; environmental, social and economic consequences certainly depends on scale of biomass use, but are to a significant degree determined by the deployment strategy and local conditions, not the least existing land uses and governance structures in place. There is ample documentation showing that biomass use for energy can cause negative impacts even if still occuring at a rather small scale. Conversely, numerous studies have shown that the consequences of bioenergy expansion can in many places be positive. More research is needed to clarify how mobilization of bioenergy supply chains can bring multiple benefits and help promote sustainable land use with higher land and water use productivity.

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Bioenergy implementation to reduce environmental impacts - an illustrative example

As noted above, bioenergy systems can – through strategic location, design, management and system integration – offer additional environmental services that, in turn, create added value for the systems. Some bioenergy systems may be established to provide environmental services that are relevant in only specific conditions, an example being when trees are established as a wind break to reduce wind erosion. Others are systems that provide environmental services of a more general nature, for instance soil carbon accumulation leading to improved soil fertility and enhanced climate benefit. Below, an example is presented of how bioenergy plantations can be used to address water quality concerns.

The Fuhrberg catchment area, which is situated about 30 km north of Hannover in northwest Germany, serves as an aquifer that supplies about 90% of the annual water demand of the city of Hannover. As in most drinking water catchment areas, groundwater protection is a major priority, and concern about the negative impacts of agricultural land-use on groundwater quality has resulted in several measures. These include: (i) voluntary agreements with farmers to reduce to a minimum fertilizer applications; (ii) initiatives to increase the proportion of deciduous forests in the catchment area; and (iii) schemes to set aside arable land, so as to reduce nitrate leaching from soils. However, it has proven difficult to keep the nitrate concentrations in the catchment area below the legal threshold (50 mg/L NO_3). Reducing nitrogen input results in crop yield losses and does not decrease significantly the levels of nitrate seepage. Even on set-aside land, nitrate seepage concentrations that are above the limit can occur.

The explanation for this phenomenon is found in the water and land-use history. Since 1960, the provision of drinking water to the city of Hannover has lowered the groundwater table, making wet grasslands drier, and large grassland areas that contained high levels of soil organic carbon (SOC) were shifted to arable land between 1960 and 1970. The resulting SOC mineralisation results in both CO_2 emissions to the atmosphere and nitrate leaching into the groundwater, which to this day influences the quality of the groundwater, since under present conditions it will take 50 to 100 years for the soils to reach a new chemical equilibrium.

Thus, setting aside the land does not have the desired effect on nitrate levels, and the only way to reduce N-output to the groundwater is to convert arable land that contains high levels of SOC into forest or continuous grassland. A promising strategy that combines groundwater protection and agricultural reactivation of fallow land might be the establishment of short-rotation coppices (SRC) that contain willow and poplar trees. These bioenergy production systems might even improve the quality of the groundwater, as compared to fallow areas. SRC with willow and poplar trees can contribute to groundwater protection, especially through their strong potentials to fix nutrients. High-level production of biomass associated with a high rate of nitrogen fixation can reduce the nitrate leaching potential of soils. Therefore, the establishment of SRC on soils that have high potentials for nitrate leaching is a promising option for arable land that is about to be set aside for groundwater protection and compensation reasons.

More information about the Fuhrberg example can be found in Schmidt-Walter and Lamersdorf (2012)

6 Global biomass resources in a European energy perspective

Over the last decade, the use of biomass for power and heat production in Europe has increased as a measure to reduce GHG emissions. A substantial fraction (around 20 TWh) of this biomass consumption currently involves long-distance import of pellets, mainly from North America and Russia. Reducing GHG emissions in Europe by Year 2030 and by Year 2050 means that imports of solid biomass for energy purposes will increase, assuming that biomass can be sourced from other regions of the world.

Global biomass potentials

During the past 20 years, several studies have been undertaken regarding the global potentials of biomass for energy purposes. These studies vary with respect to the types of biomass included, time perspectives, and limitations, such as the area available for energy crops, agricultural development, world population growth, and dietary habits, as well as technological, economic, environmental, and ecological constraints.

Comprehensive compilation and analysis of previous global biomass studies have been performed by Slade et al (2011), in which they reviewed more than 90 global studies, which could be divided into the four groups described in Table 6.1.

The values listed in Table 6.1, which span from 0 to 1600 EJ, can be compared to the global primary energy supply, which in 2008 amounted to roughly 550 EJ (Slade et al., 2011) and which is estimated to be in the range 600–1040 EJ in 2050 (Lysen et al., 2008).

Table 6.1. *Common assumptions made for low, medium, and high estimates of biomass potential (adapted from Slade et al., 2011).*

Grouping	Global biomass potential (EJ)	Essential pre-conditions
Low	0-100[1]	Little or no land for energy crops (<0.4 Gha total) High meat diet OR low-input agriculture[2] Limited expansion of cropland area AND high level of environmental protection Agricultural residues (<30 EJ, not included in all studies)
Lower-mid	100-300	Crop yields keep pace with demand: < 0.5 Gha land for energy crops (mostly nonagricultural) Low population OR vegetarian diet OR limited deforestation. All residues[3] (< 100 EJ, constrained use, included in most studies)
Upper-mid	300-600	Crop yields outpace demand: >1.5 Gha land for energy crops (includes >1 Gha good agricultural land) Low population OR vegetarian diet OR extensive deforestation / conversion to managed forestry All residues (< 100 EJ constrained use, not included in all studies)
High	600-1600	Crop yields outpace demand: >2.5 Gha land for energy crops (includes >1.3 Gha good agricultural land) High or very high-input farming, limited, and landless, animal production with dung recovery Low population (<9 billion) Vegetarian diet OR extensive deforestation / conversion to managed forestry All residues (< 100 EJ constrained use, not included in all studies)

Note: 1 EJ = 1 Exa Joule = 1000 Peta Joule = 278 TWh = 23.9 Mtoe.

[1] The table shows potential supply volumes. The ”Low” range include studies that show a development where the potential supply could be lower than the current use of 53 EJ, due to e.g. reduced use of forest residues as a consequence of stricter limitations from a ecological perspective and reduced use of renewable waste fractions due to increased waste prevention and material recycling.
[2] Low-input agriculture seek to optimise the management and use of on-farm resources and to minimise the use of off-farm resources, such as purchased fertilizers and pesticides, wherever and whenever feasible and practicable, to lower production costs, to avoid pollution of surface and groundwater, to reduce pesticide residues in food, to reduce a farmer’s overall risk, and to increase both short- and long-term farm profitability.
[3] Agricultural residues, forestry residues, wastes (dung, MSW, industrial)

The potentials (in the higher range) presented in Table 6.1 can be considered large to very large in comparison to the current use of biomass for energy purposes, which is estimated at 53 EJ by REN21 (2012) and split into the following categories:

- Almost 46 EJ for heating and cooling and for industrial applications. Of this, 34 EJ is "traditional" biomass energy in the form of firewood that is burned directly and usually in very inefficient devices;
- Almost 6 EJ for electricity generation and combined heat and power (CHP) generation;
- Almost 2 EJ for production of liquid biofuels for road transport vehicles.

A similar pattern emerges when the potentials shown in Table 6.1 are compared to the current global use of biomass for purposes other than energy. Slade et al.,(2011), estimated the following levels for Year 2000 (totalling approximately 200 EJ):

- Pasture: around 75 EJ;
- Food crop residues: around 60 EJ;
- Cereals (grains): around 40 EJ; and
- Industrial roundwood: around 20 EJ

Time perspective and different types of biomass

The studies reviewed by Slade et al. (2011) mostly focused on Year 2050. For the time period 2000–2030, a potential up to 200 EJ is identified, and this expands up to 1600 EJ when studies for Year 2050 are considered.

Three main types of biomass are included in biomass potential studies (the presented potentials apply to Year 2050):

- **Wastes & residues**: Originating from forestry and agriculture and organic wastes, including the organic fractions of municipal solid waste, dung, process residues etc.
    - In Slade et al., (2011), these potentials are in the range of 0–200 EJ.
    - In a review conducted by IPCC (2012), the technical potential ranges for Year 2050 is in the range of 40–170 EJ, with a mean estimate of around 100 EJ.
- **Surplus forestry products:** Other than those derived from forestry residues, these represent mainly the net growth currently left unused.
    - In Slade et al. (2011), these potentials range approximately from 50 EJ to 250 EJ.
    - In IPCC (2011), the technical potential for Year 2050 ranges from 60 EJ to 100 EJ.

- **Energy crops:** Oil crops, starch and sugar crops, and (ligno)cellulosic crops harvested from different types of land, such as surplus agricultural land, degraded land, and pasture.
    - In Slade et al. (2011), these potentials range from 0 to around 1200 EJ.
    - IPCC (2011) gives a lower estimate of 120 EJ for energy crop production in the Year 2050 with a possible surplus and good quality agricultural and pasture lands. Furthermore, the potential contribution of water-scarce, marginal, and degraded lands could add 70 EJ. Finally, assuming strong advances in agricultural technologies leading to improvements in agricultural and livestock management, an additional 140 EJ is possible, yielding a total potential of 330 EJ, according to IPCC (2011).

Considering the different types of restrictions, IPCC (2011) concludes that the potential levels of deployment of biomass for energy by Year 2050 could be in the range of 100–300 EJ. The same report states that:

> *"To reach the upper range of the expert review deployment level of 300 EJ/yr would require major policy efforts, especially targeting improvements and efficiency increases in the agricultural sector and good governance, such as zoning, of land use."*

Comparing the findings of Slade et al. (2011) and IPCC (2011), it becomes clear that the biomass potentials denoted as "Upper-mid" and "High" in Table 6.1 are very optimistic and will be challenging to achieve, especially when considering possible conflicts over the use of land for the production of food, raw materials (e.g., for replacing oil-based carbon in the petrochemical industry)[4], and energy.

The potentials proposed by Slade et al. (2011) are much higher for Year 2050 than for the period 2000–2030, which indicates that it will take time to establish, develop, and expand the systems necessary for the production of biomass. Much of this development will have to occur in the agricultural sector, since energy crops make up 60%–70% of the global potential in Year 2050. This differs significantly from the current situation in countries that have a large forestry industry (e.g., Sweden and Finland), where the high utilisation of biomass for energy purposes is based on forestry by-products and forestry residues, with only a small fraction of biomass originating from agriculture.

[4] As an example, Swedish petrochemical refineries annually use around 16.6 Mtonnes of carbon from raw oil. This is more than twice the amount of carbon that the Swedish chemical pulp industry uses from woody biomass (Hylander et al., 2013).

Global potentials for biomass usage versus global biomass energy demand

IPCC (2011) has reviewed different studies that have modelled the global energy system so as to stabilise the CO_2 concentrations in the atmosphere at different levels by Year 2100. These studies have included other types of renewable technologies (e.g., wind power and hydropower), as well as other CO_2 mitigation measures (e.g., fuel shifting from coal to natural gas, energy efficiency improvements, and large-scale application of carbon capture and storage).

Regarding biomass, 137 different scenarios were reviewed. The studies showed large variability in the demand for biomass. To achieve stabilisation of the CO_2 content at 440–600 ppm in Year 2100, the scenarios reviewed reveal the following biomass demands:

- 2020: From around 40 EJ up to slightly more than 100 EJ (median: around 55 EJ)
- 2030: From around 40 EJ up to slightly more than 200 EJ (median: around 70 EJ)
- 2050: From around 40 EJ up to around 260 EJ (median: around 110 EJ)

To achieve stabilisation of the CO_2 content at <440 ppm in Year 2100, the scenarios show the following higher demands for biomass:

- For 2020: from around 40 EJ up to almost 150 EJ (median: 60 EJ)
- For 2030: from around 40 EJ up to around 175 EJ (median: 85 EJ)
- For 2050: from around 40 EJ up to around 300 EJ (median: 155 EJ)

Consequently, in IPCC (2011), there is a reasonably good match between the possible supply (see Table 6.1) and demand for biomass on a global scale. The levels of production and use of biomass remain challenging, since they have to increase 2–3-fold compared to current levels in order to stabilise the CO_2 content in the atmosphere.

The European energy perspective

The gross inland consumption of primary energy by the EU-27 countries amounted to 74 EJ (1759 Mtoe) in Year 2010 (Eurostat, 2013a). In the same year, the consumption of biomass and wastes amounted to 4.9 EJ. Figure 6.1 shows that the consumption of biomass and wastes has almost doubled within the EU-27 during the period 2002–2011.

Rettenmaier et al. (2010) have presented a comprehensive review of studies of the biomass potential in Europe. Table 6.2 shows the result of this review for the EU-27. Most of the studies estimated technical potentials with different types of environmental constraints, i.e., very few of the studies included economic constraints.

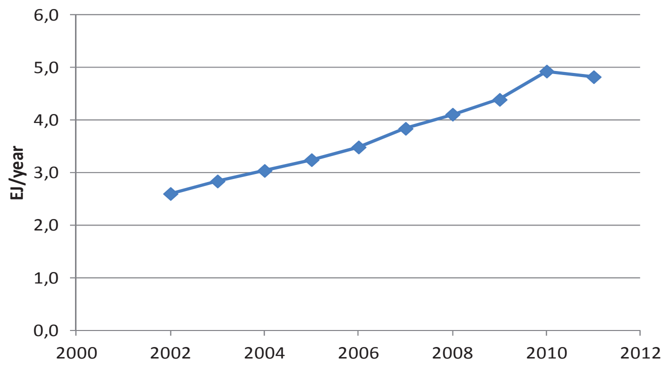

Figure 6.1. *Consumption of biomass and wastes within the EU-27 during the period 2002–2011. Consumption is calculated as: Primary production + Import – Export – Stock changes, according to Eurostat (2013a).*

Table 6.2. *Summary of bioenergy potentials (EJ/year) for the EU-27 (adapted from Rettenmaier et al., 2010).*

	2000	2010	2020	2030	> 2050
Agricultural residues & organic waste	0.5-3.9	1.0-3.9	1.5-4.4	1.1-3.1	0.7
Forestry & forestry residues	0.7-4.5	1.6-4.4	0.8-4.2	1.6-3.7	1.7-2.2
Energy crops	0.1-1.6	0.3-9.6	0.5-14.7	2.0-18.4	15.4-19.9
TOTAL	1.3-10	2.8-17.9	2.8-23.3	4.8-25.2	17.8-22.8

It is interesting to note that even the most optimistic biomass potentials revealed in Table 6.2 are well below the current level of consumption of primary energy in the EU-27. The situation in the EU-27 countries thus differs from the global situation, where the most optimistic potentials for biomass usage are on the same level as the global energy supply. One important reason is likely that Europa has a higher energy use per capita than the global average. Furthermore, in the global studies, the largest potentials are found within the regions of Russia, Canada, South America and Africa, i.e. regions outside Europe.

Biomass imports to Europe

On a global scale, Europe, and especially the EU-27, is the main importer of biomass and wastes for energy purposes. Yet, the global trade in biomass is small compared to the current levels of global production and usage of biomass for energy purposes.

According to Hansson (2013), the global trade of solid biomass and wastes for energy purposes increased from 0.06 EJ to 0.3 EJ during the period 2000–2010. In Year 2010, around two-thirds of the global trade occurred within Europe. The total global trade for energy purposes in Year 2010 can be broken down (Hanson, 2013) as follows:

- Pellets: 0.12 EJ
- Wood waste: 0.077 EJ
- Fuelwood: 0.076 EJ
- Wood chips: 0.017 EJ
- Agricultural and industrial residues: 0.009 EJ
- Roundwood: 0.0024 EJ

Pellets are the main solid biomass fuel being traded over long distances. The import of pellets to Europe from other world regions (mainly North America and Russia) has increased steadily and was estimated at 0.07 EJ (4 Mtonnes) in 2012 (Teir, 2013). Up to Year 2020, European imports from other world regions are predicted by Faaij (2013) to increase to 0.25–0.5 EJ.

The IEA (2012e) has indicated that after Year 2020 global trade in refined biomass (pyrolysis oil, torrefied wood pellets) will probably "grow rapidly and supply large bioenergy power and/or heat plants in regions with limited feedstock availability". The same source identifies likely trade routes for biomass, which are already being established today, as:

- Eastern Europe to Central Europe;
- Latin America to the USA, EU and Japan;
- Australia, which may become a supplier to China; and
- Other developing Asian and African countries, which could play an increasing role in the longer term in exporting feedstocks to Asian, European and North American markets.

Junginger (2012) presented a long-term outlook for bioenergy trade based on modelling studies. Considering "ambitious scenarios" (which are likely in light of efforts to reduce GHG emissions), they proposed that:

- By 2030, 14%–26% (10–45 EJ) of global bioenergy demand will be traded between different regions of the world; and
- By 2050, 14%–30% (15–70 EJ) of global bioenergy demand will be traded between different regions of the world.

Looking at the regional bioenergy trade balances presented by Junginger (2012), Western Europe has a net import in Year 2030 of around 0–9 EJ/yr (median, 5 EJ/yr) and in Year 2050 of around 5–10 EJ/yr (median, 7.5 EJ/yr). Other big importing regions are China and India. The main exporting regions are Russia, South America, central Africa, remainder of Africa (excluding South Africa), and Canada.

The results presented by Junginger (2012) indicate a large expansion in bioenergy trade compared to the current situation. However, it is important to note that the existence of efficient infrastructure is vital to the realisation of such potentials. In the case of Russia, Figure 6.2 shows an example of the forest road grid along the Finnish-Russian border. On the Finnish (left-hand) side of the border, the forest road grid is much more developed than on the Russian (right-hand) side; this disparity definitely affects the opportunities for utilising the forest both for material harvesting and energy purposes.

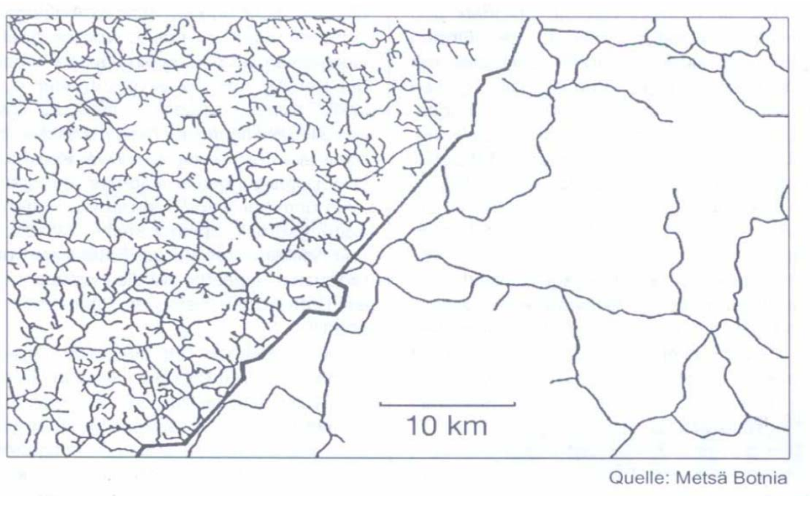

Figure 6.2. *Forest road grid on opposite sides of the Finnish-Russian border. Source: Nilsson (2013).*

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7 Safeguarding GHG savings in bioenergy through governance

While governance is needed to guide bioenergy deployment, the regulations put in place to deal with the issues of concern are not yet supported by commonly agreed evaluation frameworks. The definitions used to support restrictions on biomass sourcing influence the types and levels of biomass that can be produced in the future, and where this production will occur. However, globally agreed definitions may not be forthcoming. Similarly, the methods used to determine whether a certain bioenergy option meets the specified performance requirements can be controversial. As an example, it is presently debated as to whether bioenergy from existing forests contributes to climate policy objectives; the contrasting views are partly due to disagreement regarding the assessment methodology and as to whether assessments should consider long-term or short-term effects. It is proposed that the design of policy measures for forest-based bioenergy should balance near-term GHG targets with the long-term objective of limiting the increase in global temperature to 2°C, and should be based on a holistic perspective that recognises the multiple drivers and the effects of forest management. A strategy directed towards a more harmonised global approach is considered as the best solution for the governance of bioenergy.

As described in Chapter 4, there is an emerging consensus that governance (see definition in Textbox in Chapter 4) is needed to guide bioenergy deployment so that the resources and feedstocks are put to optimal use, and that (positive and negative) socioeconomic and environmental issues are addressed as production increases. However, the regulations put in place to deal with issues of concern are not yet supported by commonly agreed evaluation frameworks (including criteria, indicators, and definitions). For example, EU-RED established that the raw materials used for the production of biofuels and bioliquids may not be produced on lands that have a high biodiversity value (in or after January 2008), including primary forests, protected areas, and highly biodiverse grasslands. There are, however, no globally agreed definitions of primary forests or highly biodiverse grasslands, which makes it difficult to clarify some of the requirements that need to be met with respect to the biodiversity criteria.

The definitions that are used to support restrictions on biomass sourcing obviously influence the types and levels of biomass that can be produced in the future, as well as where this biomass will be produced. However, the methods used to determine whether a certain bioenergy option meets the specified performance requirements also exert an influence. Among the debated methods are those used to determine the GHG savings associated with the use of bioenergy. While the evaluation of so-called ‘first-generation’ biofuels was initially in focus, the debate has in recent years also concerned bioenergy from forests that are managed with long rotations, as discussed below.

Bioenergy from forests managed with long rotations[1]

To understand fully the climate change effects[2] of bioenergy from existing forests, it is important to consider the entire forest landscape and the wide range of conditions under which forest bioenergy systems operate, as well as the interactions between human activities and forest growth. This requires models and databases that reflect the specific context under investigation. The alternative approach of applying simplified conceptual models and crude data is not recommended, as the conditions or forest bioenergy systems vary considerably around the world.

Figure 7.1 gives simplified representations of the carbon stocks in a managed forest, which are useful for describing the principal situations that can occur and also for explaining how one can draw different conclusions concerning the climate change mitigation benefit of bioenergy when looking at forests that are managed with long rotations. Figure 7.1a shows how the carbon balance on a stand level switches dramatically from uptake to loss at final felling. The time taken to recover the carbon losses can range from decades to centuries. However, forests are not managed on the single stand level; large landscapes are managed as forest systems. Management activities in one stand are coordinated with activities elsewhere in the system, and carbon losses in some stands counterbalance carbon gains in other stands. A steady flow of harvested wood is obtained from a landscape-level system that has a carbon stock that fluctuates around a trend line that can be increasing or decreasing or roughly stable (Figure 7.1b,c).

Figure 7.1a shows the carbon stock of an individual stand, over successive rotations. The blue curve indicates the reference scenario, i.e., a forest that is harvested for timber only. The remaining curves indicate two alternative scenarios, in which harvest residues (branches and tops) are removed for bioenergy at harvest, at time T1 and at each successive harvest. The concept of "GHG cost" is illustrated in the red curve: the average carbon stocks are lower than in the blue stand, due to the removal of harvest residues, and, possibly, flow-on effects on soil carbon stocks and the forest growth rate. The green curve illustrates how enhanced forest management reduces the GHG cost. Figures 7.1b and 7.1c show the total carbon stocks summed for a landscape of multiple stands at different stages in the rotation cycle, assuming that all stands follow either the blue, red or green curve in Figure 7.1a.

In reality, the forest carbon stock on the landscape level reflects a mixture of different

[1] The information in this section is based on Cowie et al., 2013.

[2] In addition to their direct effects on GHG emissions and sequestration, bioenergy systems affect the climate through: (i) climate forcing related to particulate and black carbon emissions from small-scale bioenergy use and changes in surface albedo; and (ii) the indirect effects of bioenergy use, such as the influences that the prices on wood and petroleum markets have on consumption levels and investments in the forestry and petroleum sectors, as well as in various other sectors that are sensitive to biomass and petroleum prices.

management approaches applied to different stands (it may also include adjustment to the rotation period, although this is not included here). In Figures 7.1b and 7.1c, an additional curve (in purple) shows a scenario in which changes in forest management across the forest landscape outweigh the effect of increased biomass removal for bioenergy, so that the forest carbon stock increases on the landscape level. Figure 7.1c shows a situation where the carbon stocks across the landscape are increasing, i.e., where the national estate is dominated by young stands; over time, the total carbon stocks increase as these stands mature. Although the total stocks continue to increase in all scenarios in Figure 7.1c, biomass removal can lead to "foregone sequestration" (red curve), although this can be reduced or avoided through enhanced forest management (green and purple curves).

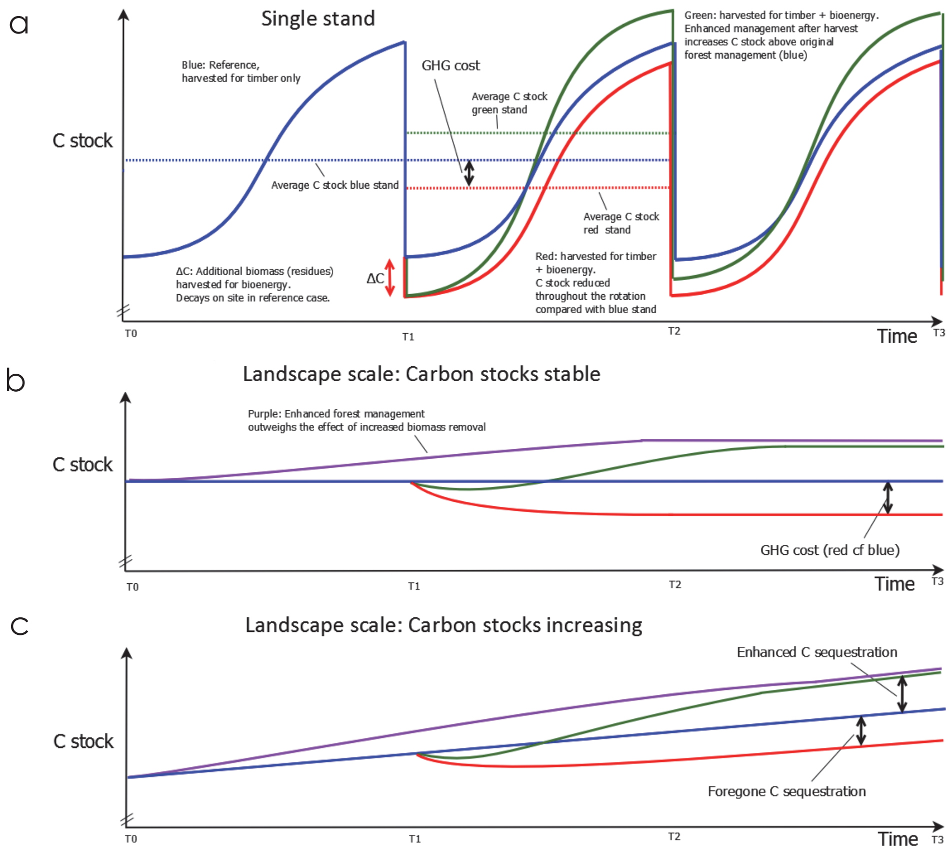

Figure 7.1. *Simplified representations of the carbon stocks in a managed forest, neglecting the carbon stock fluctuations around the curves caused by climate variation and forestry operations, such as thinning.*

If, for example, logging residues are collected and used for bioenergy, the carbon in these residues will be retained in the forest for a shorter time period than in a reference scenario in which these residues are left to decay in the forest. From the stand-level perspective, the collected logging residues are accounted for as a carbon loss from the stand, i.e., GHG emissions. Consequently, if the climate benefit is assessed on a stand level and if GHG emissions accounting starts at the time of the residue collection, one finds that the use of logging residues for energy results in upfront net GHG emissions unless energy systems that give very high levels of GHG emissions are displaced (e.g., efficient biomass CHP displaces a combination of old, inefficient, coal-fired condensing power and heat boilers that use coal).

However, if the assessment is performed on a landscape level, it is found that gradual implementation of residue collection at logging sites has a relatively small influence on how the total forest carbon stock changes, as these changes are influenced primarily by how forest owners plan their management and harvesting regimes based on expectations of future markets (for bioenergy and other forestry products). The forest carbon stock responses to changes in forest management depend on the characteristics of the forest ecosystem and on which specific changes are implemented. Accounting at the landscape scale integrates the effects of all the changes in the forest management and harvesting regime that take place in response to bioenergy demand. Taken together, these changes may have a positive or negative influence on the development of forest carbon stocks as a whole.

It is proposed here that the design of policies for forest-based bioenergy should attempt to balance near-term GHG emissions targets with the long-term objective of limiting the increase in global temperature to 2°C, and should be based on a holistic perspective that recognises the multiple drivers and effects of forest management. Otherwise, there is a risk that policies will fail to promote outcomes that simultaneously address the production and conservation objectives. Policies should be devised to promote the optimal use of land and biomass resources. The consequences for climate of forest bioenergy deployment should be addressed at the larger landscape scale, as opposed to the stand level.

The way forward for bioenergy governance

Researchers in the Pathways research programme have engaged in IEA Bioenergy, which provides a platform for discussions, guidance, independent views, and analyses to improve the effectiveness of sustainability governance, with the goals of benefitting sustainable bioenergy deployment both locally and globally. In addition to publications in support of policymaking and strategic planning in industry (see for example, Berndes et al., 2011; Cowie et al., 2013), events have been organised to facilitate the dialogue that is critical for the formulation of rational policies towards the implementation of sustainable bioenergy production systems. These events have gathered together participants who represent conservation organisations, government agencies, universities, and the forestry and renewable energy industries. Various publications have emerged from these events (IEA Bioenergy, 2013; Pinchot Institute, 2014).

A study[3] undertaken by IEA Bioenergy to monitor the actual implementation process for sustainability certification of bioenergy discovered the lack of a global/common definition of how the sustainability concept should be translated into practice, i.e., how to measure sustainability and which criteria/indicators should be used. A summary report from the study highlights the main issues related to the implementation of sustainability certification and makes recommendations as to how these issues can be addressed (see Text Box below). The report points to some early actions in that direction, such as mutual recognition of some certification schemes and harmonisation initiatives, such as ISO and CEN for standardisation. Consistency and transparency, and the engagement of stakeholders across sectors and geographical locations are considered crucial to the success of these efforts.

[3] The study was carried out by an international group of researchers (including Pathways' researchers Oskar Englund and Göran Berndes) who engaged with IEA Bioenergy. Four reports and a summary report can be downloaded from the url:s listed below:
www.bioenergytrade.org/publications.html#Monsum;
www.bioenergytrade.org/publications.html#Mon1;
www.bioenergytrade.org/publications.html#Mon2;
www.bioenergytrade.org/publications.html#Mon3;
www.bioenergytrade.org/publications.html#Mon4.

Summary of the main issues related to the implementation of sustainability certification for biomass

New policies should take into account how biomass markets operate and evolve (e.g., investment decisions, role of smallholders, technological developments). Further deployment of sustainable bioenergy requires clear, transparent, and stable policy pathways with clear implementation procedures, including the ways in which changes will take into account new insights. Changes should be implemented using a transparent step-by-step approach. Development of an international framework of (minimum) standards could improve the coherence between the various emerging country-/region-based and industry-specific policies and requirements.

Voluntary schemes and regulations can be complementary tools. Certification can serve as an on-the-ground tool for implementing higher-level legislative requirements for sustainability. Certification can be adapted faster than legislation and may serve to elucidate how continuous improvement of sustainability performance can be achieved, based on scientifically based developments and management practices. However, requirements that are legislated for in response to internationally agreed standards are needed to encourage further sustainable market deployment.

Certification schemes can serve as alternative tools for ensuring the sustainability of biomass from regions where policies and governance structures are weak. Risk evaluation systems could be used to determine the need for certification in addition to the legislative systems.

The main drivers for companies to seek certification are desires to comply with legislated requirements and to maintain or gain market access. However, obstacles to becoming certified, such as administrative complexity and high costs, remain for some actors.

Companies can use guidance to select a scheme that fits with the company's strategy, structure, and market position. The credibility of a scheme is a key selection criterion for companies that consider joining. Compliance with codes of good practice, which are being developed by the International Social and Environmental Accreditation and Labeling Alliance (ISEAL) and similar organizations, could be used as a guiding principle.

The proliferation of schemes has led to competition among the schemes in the market. This may bring further improvements in efficiency and effectiveness, although a plethora of different approaches and requirements may also lead to confusion in the market-place. There may be a tendency to use the least-demanding system or even towards 'green washing'. With regard to the ease with which a scheme can be implemented, a good balance is needed between comprehensiveness and the economic and administrative accessibilities of schemes. Systems should converge to a level that ensures consistency and transparency, without losing relevance at local levels. Unilateral recognition and mutual recognition are important instruments. While convergence to achieve consistency is sought after, it is also desirable to maintain incentives for superior performance, e.g., by classifying systems according to their sustainability levels and enforcement standards.

A cross-sectoral approach that covers harmonised global sustainability principles and certification systems would be advantageous with respect to the uniform application and implementation of sustainability criteria and the avoidance of leakage. Criteria for the sustainable production of biomass should be developed for and applied to all uses of biomass (food, feed, fibre, fuels).

To ensure legitimacy and to increase trust, certification schemes should be developed using a multi-stakeholder approach, in which communication and transparency are key elements.

Certification can be costly, in particular for small-scale players. Solutions are needed to reduce the administrative and economic burden, improve the cost efficiency of the process, and ensure a fair distribution of costs along the supply chain.

To the extent that developing countries wish to enter international markets with sustainability requirements, they should be given time and support to enable them to improve enforcement of existing sustainability requirements and, if needed, develop these to match the requirements of international markets.

This textbox is based on the work presented in Pelkmans et al., 2013b.

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8 Estimation of the onshore wind power potential in EU-27

As a consequence of European energy and climate policies, the level of onshore wind power in Europe is likely to increase substantially up to Year 2050. Such development raises questions related to the potential of exploiting land for wind-power installations. Using a GIS-based reduction method, this work shows that a large proportion of the land surface area of Europe is available for wind power, bearing in mind the limitations imposed by densely populated areas (cities), lakes, rivers, environmentally protected areas (Natura 2000), and roads. Based on this approach and combined with wind availability data, we present an estimate of the realistic potential of onshore wind power of 2 000–3 000 TWh, i.e., 50%–80% of existing gross demand for electricity in the EU. Clearly, significant uncertainties exist regarding the estimate itself and the interpretation of the concept of "realistic" potential.

Method for assessing available land surface

The assessment of available land surface in the EU-27 countries for onshore wind power installations has been made using a global information system (GIS) tool, which was applied to single grid cells with a resolution of 200–670 square kilometres across the EU-27. The assessment was performed by calculating the geographical area for each cell that remained after lakes, rivers, cities, Natura 2000 areas, and major roads (i.e., the so-called "reduction" areas) were eliminated from the area represented by the countries studied. All calculations have been performed using the GIS program ArcInfo. Thus, the remaining area within each grid cell is considered as being potentially available for wind power installations (Figure 8.1). Given the high-order spatial resolution used, the results have also been aggregated to a coarser level, defined by the NUTS2 level[1], in Figure 8.2.

[1] The NUTS classification (Nomenclature of territorial units for statistics) is a hierarchical system for dividing up the economic territory of the EU for the purpose of e.g. socio-economic analyses of the European regions (definition taken from Eurostat, http://epp.eurostat.ec.europa.eu/portal/page/portal/nuts_nomenclature/introduction)

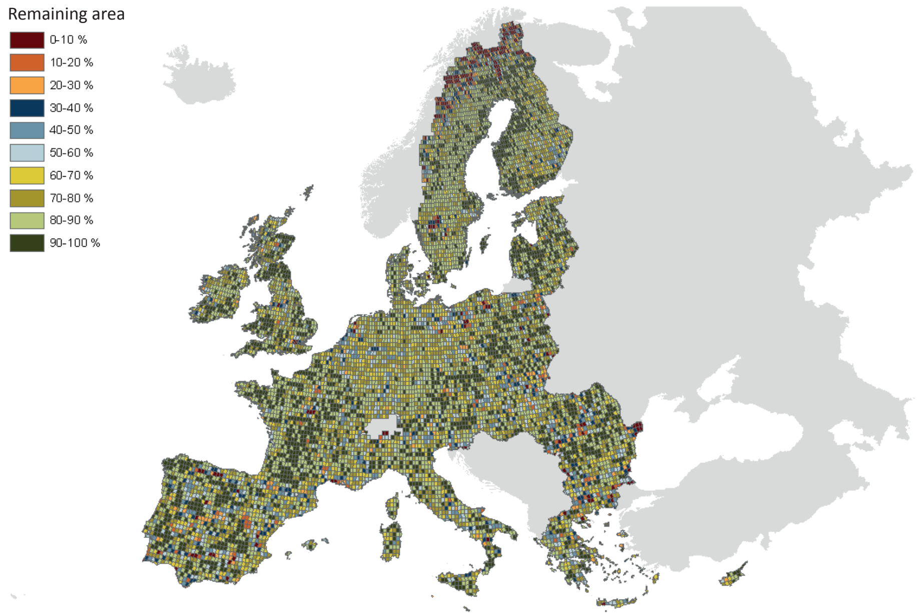

Figure 8.1. *Geographical grid cells indicating percentages of land available for wind power installations in EU-27.*

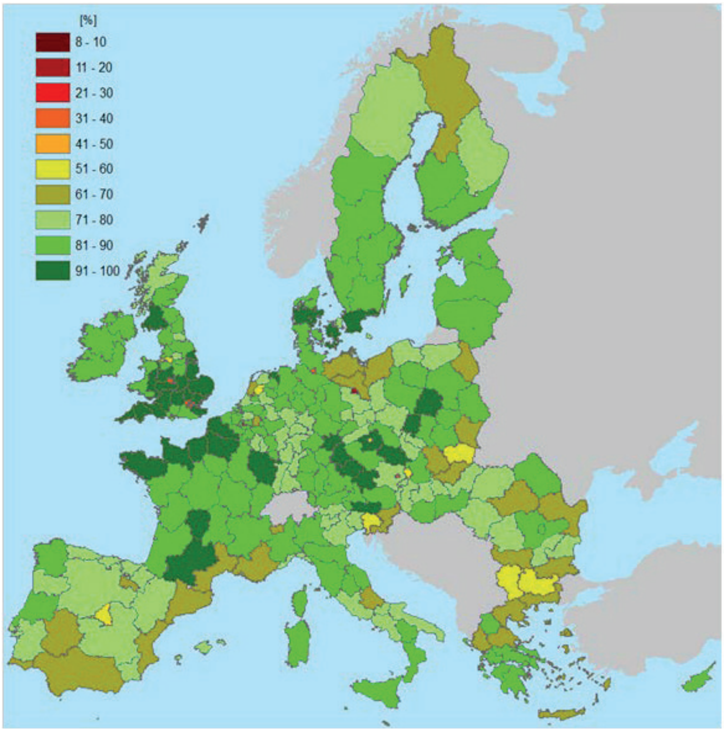

Figure 8.2. *Remaining areas available for onshore wind power installations, shown at the NUTS2 level.*

For the assessment of reduction areas, buffer zones were included in all cases, with the exception of the Natura 2000 areas. This means that not only the area of, for example, a city in itself was reduced, but also a "safety" perimeter of, in this case, 1 000 meters, so as to reflect concerns of visibility and noise associated with wind power installations.

The method described so far yields an estimate of the available *land surface* for onshore wind-power installations. In order to assess the potential in TWh we also need to consider wind *availability*. This is discussed futher below in this chapter.

In reality, several aspects in addition to those included here must be taken into consideration when assessing potential sites for wind power, such as proximity to the electricity grid, the need for adequate transport routes for the establishment of wind power, the presence of military areas and heritage sites, and other environmental considerations not included in the Natura 2000 restriction. Thus, the task of identifying available wind-power sites offers unique challenges in that the parameters may differ significantly between individual projects. Nevertheless, the present study aims to estimate the extent of the potential for onshore wind power generation in Europe as a whole, and to place this potential in the contexts of long-term policy goals and electricity-demand projections. To achieve such an aim of the present study, simplifications are inevitable. Furthermore, estimates of the costs and potentials of wind power and other renewable electricity options are required by the energy systems models, which are key elements of the research reported in the present book.

Extensive land areas available for onshore wind-power installations

Even though the importance of the reduction areas investigated here is significant, the remaining area after removing the reduction areas (or "no-go areas" for wind power installations, as defined here) is of considerable size. Based on the highly detailed GIS-modeling but the relatively limited amount of reduction areas, we estimate that around 70 percent of the land surface within the EU-27 would be available for onshore wind power installations (see Figure 8.3). This is, however, by far not the same as saying that this would be profitable. As mentioned before we need to look also at wind availability in order to assess profitability.

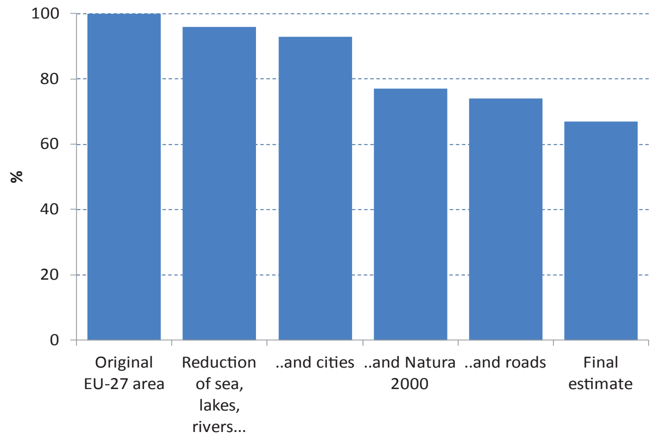

Figure 8.3. *Available land surface area for onshore wind power installations with elimination of the different reduction areas. Given the limited data available for cities, a final rough estimate was made.100 percent equals the total geographical area of the EU-27.*

Estimation of cost-supply of European wind power

The cost-supply estimate for onshore wind power in the EU-27 is produced by combining the available land surface in each grid cell and the wind availability data for the same grid cell.[2] Furthermore, to extrapolate the potential from land area (km^2) to production level (TWh), we need to assume a power density, typically expressed as kW/km^2. For a typical wind farm, the power density is about 10 000 kW/km^2. If we multiply that figure by the estimated available European land area we end up with an onshore wind power potential of approximately 30 000 GW. This would be more than sufficient for supplying the entire European continent with electricity in the future. A similar estimate was made by the European Environmental Agency (EEA, 2009), for which they used a method similar to that reported here. The EEA estimated a potential of roughly 40 000 TWh considering the reduction areas mentioned here. However, in our ambition to estimate a potential in terms of available surface that is realistic (rather than a theoretical potential), we do not assume that the European land surface area that remains after the subtraction of the reduction (or "no-go") areas described above, would be available for wind-farm installations. In reality, some of these areas will be used for wind farms, whereas others will not. In some cases, exploitation will involve only single turbines. Thus, the choice of power density is dependent upon the specific region, and it is likely to differ significantly between different regions or, in this case, different grid cells. To arrive at a European estimate of the potential for onshore wind power, we have to introduce some simplifications. Therefore, we have chosen an all-European power density based on the European regions in which spatial wind power density is very high. In the German region of Schleswig-Holstein, for instance, the power density is about 250 kW/km^2 if we exclude the reduction areas from the available surface estimate. Since the average wind turbine size in this area is around 1 MW, it is reasonable to expect a higher power density in the future, since the new replacement wind

[2] Wind availability data are based on the wind-speed database managed by ECMWF (European Centre for Medium-Range Weather Forecasts).

turbines will generally be larger. This type of "repowering" development may lead to increased power densities without any significant exploitation of new sites. Based on this, we use an indicative power density of 550 kW/km^2 across all the grid cells. An alternative and more realistic approach might have been to apply a larger power density to areas with good wind conditions and a lower power density to areas with relatively inferior wind conditions. On the other hand, exploiting good wind conditions, such as those in coastal areas, may lead to conflicts with interests that are not a concern in areas with relatively worse wind conditions, such as inland forests.

The resulting cost-supply curve for onshore wind production in the EU-27 is presented in Figure 8.4. The figure shows that costs (including capital costs) increase as the aggregated potential increases. This is due to falling full-load hours (also shown in the figure), which is assumed to be the only cost difference between the different grid cells. The estimated potential is 2 000–3 000 TWh. However, around half of that is available at a cost >100 €/MWh. Modelling of the European electricity system (see e.g. Chapter 10) indicates that European wholesale prices will typically be <55 €/MWh in the coming decade. Thus, in order to increase significantly the contribution from wind power, additional support is necessary. On the other hand, the levelised costs of wind power continue to drop due to technological developments and, in a longer-term perspective, carbon costs for climate change policies are likely to increase wholesale prices for electricity. Therefore, the share of the identified potential that is profitable in the absence of additional support may increase in the future.

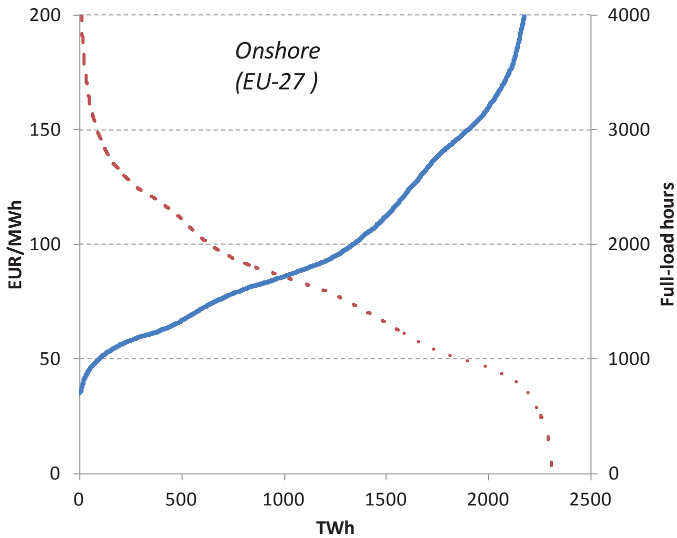

Figure 8.4. *Cost-supply curve (blue) for onshore wind power in EU-27 as obtained from the estimates made in the present work. Investment cost is assumed to 1400 €/kW at 8% discount rate, 25-year economic life, 15 €/kW operations and maintenance (O&M)costs, and assumed power density of 550 kW/ km^2. The red dotted line represents the corresponding full-load hours.*

Norway and Switzerland are omitted from this analysis. If we, for the sake of simplicity, assume that the share of available land surface for onshore wind power installations is the same for Norway and Switzerland as in the rest of the EU, and that full-load hours typically amount to 2000 hours annually, the contribution to the European onshore wind power potential coming from those two countries amounts to approximately 300 TWh.

Finally, the current (2013) wind-power production of the EU-27 countries under normal-year conditions is around 230 TWh according to the European Wind Energy Association (EWEA). Since we in our analysis have not made any distinction between existing wind power installations and new installations, the current production volume of 230 TWh is a part of the entire potential presented in Figure 8.4.

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9 The resource potential of solar power in EU-27

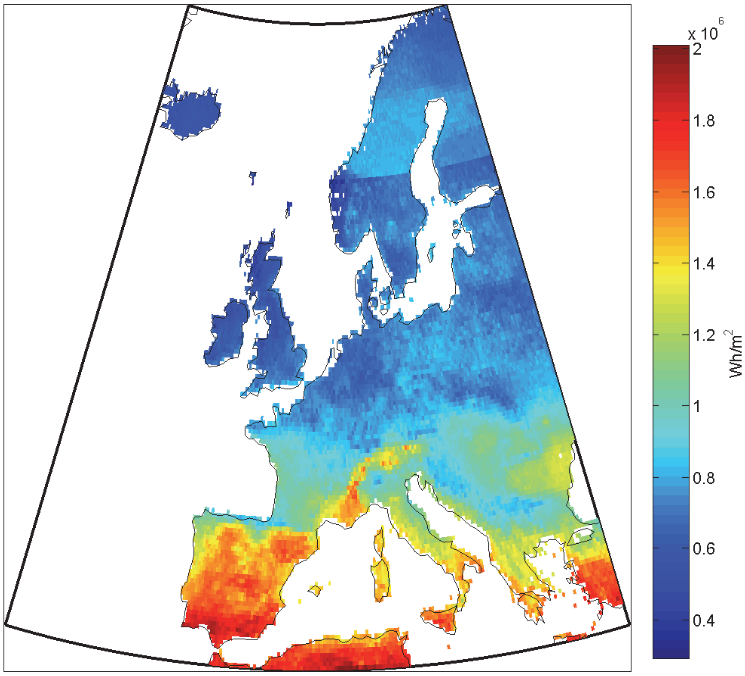
The global trends for the rapid growth of solar power in the last few years will likely continue in Europe as the levelised cost of electricity and heat from these technologies continues to decline. To be able to compare the myriad of technologies used for solar power and heat in terms of economic potential across the vast geographic diversity of Europe, the first step is to understand the types of solar resource that each technology can utilise.

Solar technology-resource coupling

Solar energy is harnessed today, in practice, by two main types of technology: thermal systems collect the light from the sun and either use the thermal energy directly or convert that thermal energy to electricity through a heat engine, whereas photovoltaic (PV) systems convert the photons from sunlight directly into electricity in a semiconductor device. Solar collectors are usually more efficient at converting photons into usable thermal energy than electric power. When it comes to electricity production, however, although the photovoltaic process is more direct, the overall efficiency (percent of sunlight incident that is converted to electricity) of commercial solar thermal-electric and photovoltaic systems fall in similar ranges (10-30%), with the high end of this range reached for both high concentration PV systems and some concentrating solar power (CSP).

All solar power technologies collect electromagnetic radiation from the sun to generate electricity, but if a system optically concentrates the light (e.g. CSP) it collects primarily the direct portion of the radiation, whereas non-concentrating systems (e.g. flat plate PV) can collect both the direct and diffuse components of sunlight. The direct component of radiation (coming straight from the sun without being scattered or reflected on its way to the collector) makes up the vast majority of sunlight in the equatorial and sunniest locations around the world; but diffuse light (light that has been reflected and scattered on its way to the collector) is a major portion of total sunlight in the more polar and less sunny areas of the world. Figure 9.1 shows the three components of irradiance incident on an optimally-tilted flat-plate collector throughout Europe.

a)



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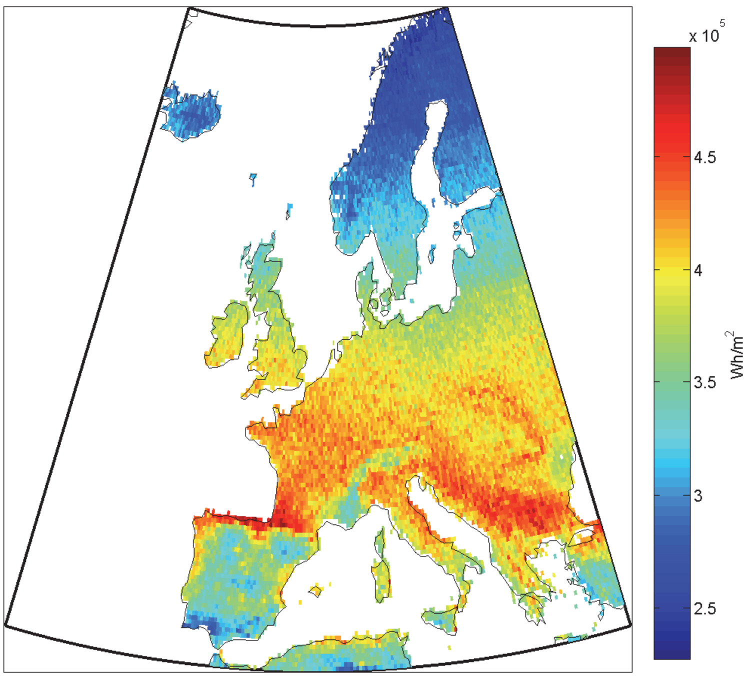

c)

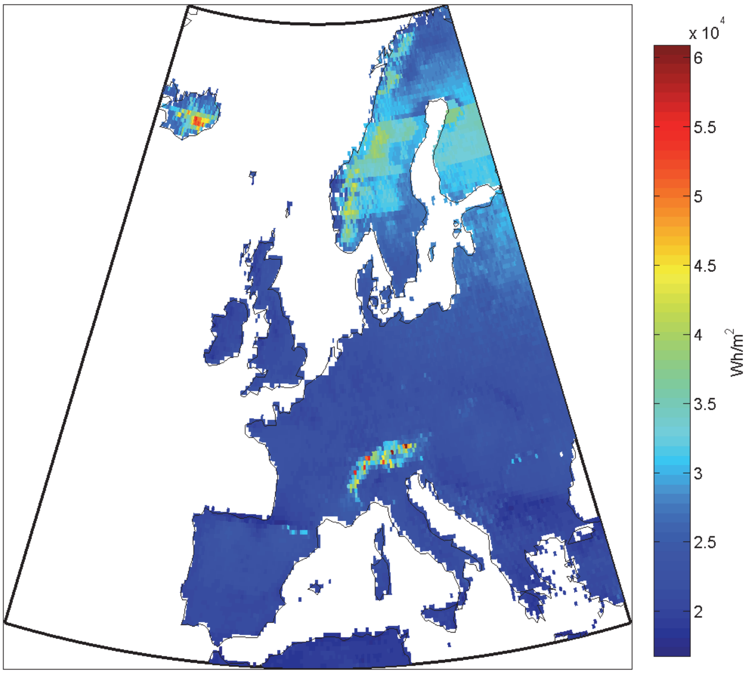

Figure 9.1. *Annual solar irradiance incident on a flat-plate collector tilted at a fixed angle to maximise the yearly total of the three components of radiation: (a) the direct beam and forward scattered circumsolar diffuse component, (b) the non-forward scattered diffuse component, and (c) the ground reflected component incident per square meter. Note that the colour scales differ between the subfigures.*

Since only direct light can be optically concentrated, concentration requires the ability to track the sun so that the collector is always pointing directly at the sun as it moves across the sky, thus further complicating such systems. However, since solar thermal-electric efficiency benefits greatly from generating higher temperatures to drive the heat engines (Rankine or Stirling cycles) that convert the thermal energy to electricity, concentrating systems are the standard in this field. Figure 9.2 shows the potential irradiance that a tracking concentrating collector can harness throughout Europe.

Note that although the tracking concentrating collector only uses the beam (and forward scattered) components of the radiation, there is still a substantial increase in the total resource available in most of Europe if one compare to the sum of the beam, diffuse, and ground reflected components incident on a stationary flat-plate collector. In the clearest areas, including the alps and southern Europe, the advantage of tracking and concentration is greatest. In the cloudiest and foggiest areas, including the British isles and most of the central European latitudes between Scandinavia and the alps, flat-plate collectors have more favorable resource potential.

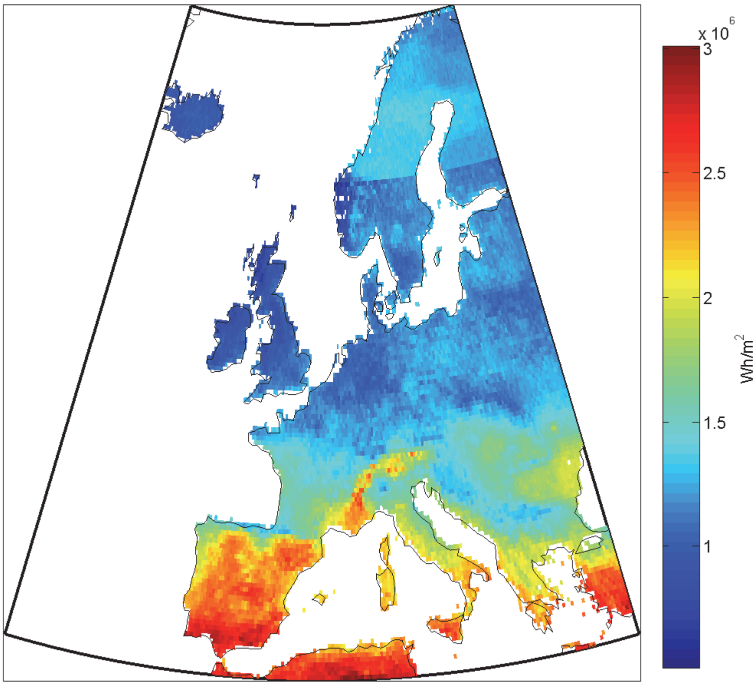

Figure 9.2. *Annual solar irradiance incident on a dual-axis tracking concentrating collector is composed almost entirely of direct beam radiation: (above) the direct beam and circumsolar forward scattered diffuse component incident on one square meter of such a collector.*

In the case of photovoltaics, there is also a potential, due to the properties of the PV cell material, to increase efficiency and substantially decrease the needed amount of the sometimes expensive photovoltaic material by using concentration. This is typically done using exotic multi-junction high-efficiency solar cells. The economics of concentrating PV (CPV) are not as favorable as in the CSP case, because CPV increases the need for cooling, in addition to the tracking and more complex optics required, and there is typically not as strong an increase in efficiency with concentration as in thermal systems. Chapter 19 gives an overview of the main characteristics of the different solar technologies.

Variability of solar power

The output of all solar power systems varies directly with the amount of sunlight, so is highest during the summer, tapers off in the winter, and varies depending on seasonal weather patterns. Regions nearer to the equator see less seasonal variation and, as seen in Figures 9.1 and 9.2, increased total production.

Figure 9.3 shows the total production of solar electricity in Germany in 2013 compared to the corresponding production from wind turbines in that year. Note that the seasonal variation of these technologies makes them good complements for each other, as wind is often stronger in the winter months and solar in the summer months.

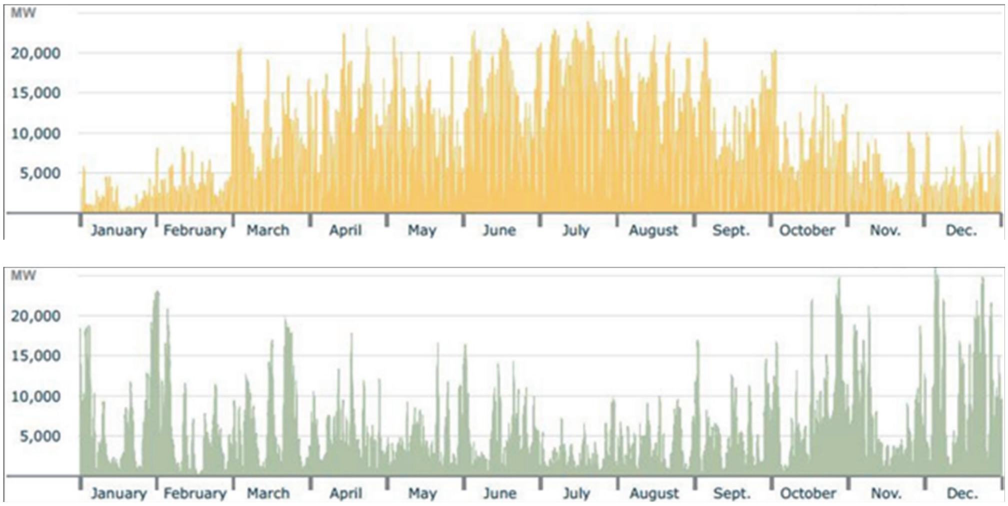

Figure 9.3. *Solar electricity production in Germany, 2013 (top) compared to (bottom) wind electricity production in the same year. Source: Fraunhofer ISE (2013).*

Resource potential

Looking at Figures 9.1 and 9.2 on the incident irradiance on a solar collector and comparing that to the total primary energy demand of Europe, which was $2.3 \cdot 10^{16}$ Wh in 2011 (IEA, 2013), we can see that depending on region between 120 and 600 times more solar energy can be collected per square meter of collector in the EU-27 than the average current primary energy demand per square meter. For comparison, 5% of the EU land area is currently covered by buildings, roads, and artificial areas (Eurostat, 2013b), but using 0.2% (best solar regions) to 1.0% (worst solar regions) of the land area for solar collectors would collect the same amount of solar irradiance as the entire primary energy demand of the EU-27. Hence, one can conclude that, from a resource perspective, solar energy has the greatest utilizable potential of any renewable technology, but it is also inherently variable, so accurate forecasting and storage will need to be part of any system that utilizes high levels of solar energy.

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The long-term development of the European electricity-supply system

– Scenario analyses

The transition of the energy and electricity systems is subject to significant uncertainties. Consequently, in this main section we present, among other things, four main scenarios for the long-term development of European electricity generation up to Year 2050. Depending on the policy choices that are made and technological advances, the development pathways of the scenarios may differ significantly, even though they share common goals, such as ambitious targets for climate change mitigation. We also present special cases that highlight important considerations and possibilities within the European electricity system. These include the German nuclear phase-out programme, exploring the possibility of carbon-free Nordic electricity exports, and the potential for natural gas to be a game changer under certain conditions.

10 Four scenarios for the European electricity generation

Significant uncertainties related to the implementation of EU energy and climate policies post-2020 and regarding the long-term development of the energy markets mean that there is a need to apply scenario analyses to assessments of the long-term development of the European electricity system towards Year 2050. In this chapter, we present the assumptions and model results associated with the four main scenarios (”pathways”) defined during the course of the research work. The scenarios cover multiple aspects, such as the diversity of climate policies (one “overall climate target” or several goals that include also targets for renewable energy and efficiency), technological developments for CCS and renewables, and whether policy instruments are implemented nationally or across the EU. The results of the modelling show that the outcomes of the four main scenarios differ significantly from each other in many aspects. A continuously increasing supply from renewable electricity (RES-E) is a robust result across the scenarios. However, the total volume of RES-E is scenario-specific. Furthermore, the developments in the marginal costs of electricity and marginal reduction costs of CO_2 are significantly affected by the choice of policy set-up and other scenario-specific considerations. This has, of course, a significant impact on the long-term development of several important energy markets across Europe.

The energy and climate policies of the EU towards Year 2050 have been previously discussed in this book (cf. the *”Setting the scene”* main section). Meeting these targets will have profound impacts on the European electricity-supply systems, as we will show in this chapter. However, there is currently much uncertainty regarding the extents to which the policy agenda will eventually be implemented across the Member States, as well as concerns as to the design and structure of the necessary policy instruments. Not only policies, but also the development of international and domestic fuel markets, electricity demand, and technological developments are factors that are associated with a high degree of uncertainty and that largely determine the development of the electricity system. To handle such uncertainty and to assess the possible outcomes based on the choice of these factors, we introduce four main scenarios for the development of the European electricity-supply system. Each scenario describes a possible development given a unique combination of the impact factors mentioned above. The two main dimensions that define the scenarios are policy and technological development. The technological dimension deals with the availability and development of certain technologies, such as renewables, nuclear power, and CCS. The policy dimension deals with the degree of policy intervention and the set of policy instruments. Such intervention may be limited to reductions in GHG emissions or it may be extended to include policies for renewables and efficiency measures. Together with projections for electricity demand and technological developments, they define the main assumptions that are used as the input to the model analysis of each scenario. Our main scenarios are concentrated on the supply side. Electricity demand is given (different demands across the scenarios) and we do not specifically analyse demand-side measures or flexibility. These four main scenarios, thus, describe different *pathways*, for the European electricity system towards Year 2050.

The four main scenarios are:

- **Reference**, which assesses the consequences of existing policy instruments. This scenario is based on the reference projection of the EC (2013);
- **Regional policy**, which assesses the consequences of a stringent climate-mitigation target in the EU, with almost 100% reduction of CO_2 emissions in the electricity-supply system, together with dedicated policy targets for renewables and energy efficiency. This scenario is loosely based on the EC Roadmap scenario “Energy efficiency” (EC, 2011);
- **Climate Market**,which assesses the consequences of a similar stringent climate-mitigation target as Regional Policy, but concentrated exclusively on reducing CO_2 emissions, and not, specifically, on increasing the share of renewables and efficiency. This scenario is inspired by, and loosely based on, the EC Roadmap scenario “Diversified supply technologies” (EC, 2011) and the “Powerchoices Reloaded” scenario analysis initiated by Eurelectric (2013);
- **Green Policy**, which assesses the impact of an electricity-supply system that is close to 100% renewable by Year 2050. This scenario is loosely based on the EC Roadmap scenario “High RES” (EC, 2011). However, the primary objective of this scenario is to analyse a European electricity system that is almost exclusively made up of renewable electricity generation. The conditions for reaching such a system are, in this case, of less relevance.

Key scenario assumptions

The assumptions as to electricity demand are given in Figure 10.1. Gross electricity demand is provided exogenously to the model (the ELIN model) and is therefore not a model result in itself. Since Year 1990, electricity demand has increased steadily in the EU as a whole. During the global recession of 2008–2009 and the financial crisis in Year 2011, electricity demand fell significantly (see Figure 10.1). Demand projections for the Reference scenario follow the latest model-based projection by the European Commission (EC, 2013). Thus, electricity demand in Year 2050 is around 30% higher than the current level. For the Climate Market scenario, we assume that demand partially follows that of the Powerchoices Reloaded study (Eurelectric, 2013). In that study (as in our Climate Market scenario), assumptions related to increased electrification in transportation, industry, and the heating market across the EU affect the long-term electricity demand. In the Green Policy scenario, we assume that the very large penetration of renewable electricity is facilitated by flexible and efficient electricity use. Thus, we assume that electricity demand is lower than in the Reference scenario, yet increasing compared to its current level. Finally, the Regional Policy scenario is characterised by ambitious end-use efficiency polices that keep demands for electricity and other final energy uses at relatively low levels. We assume that the level of demand in this scenario lies roughly intermediate to those of the EC Roadmap “Energy efficiency” scenario and the ADAM-450 scenario (EC, 2011 and Fraunhofer, 2006). In the scenario assumptions, there are large differences between the Member States. Figure 10.1 shows the assumption on gross electricity demand for the EU-27 plus Norway plus Switzerland as a whole.

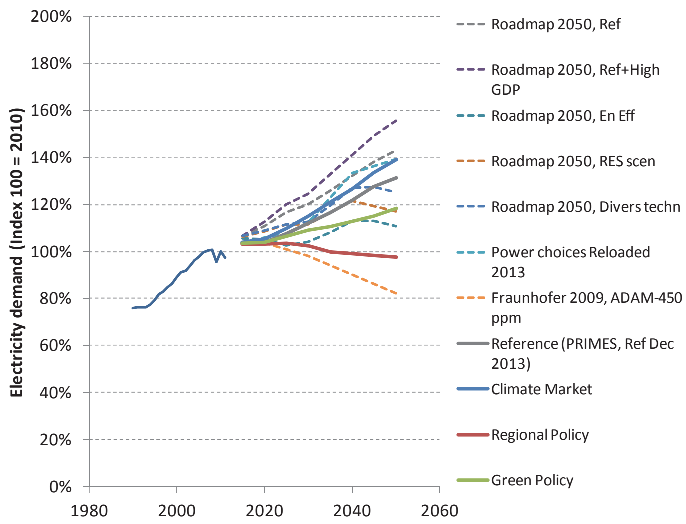

Figure 10.1. *Assumptions made regarding gross electricity demands in the four main scenarios and in some other studies (demand includes transmission losses but excludes own-consumption in power plants and use in pumped hydro). Gross electricity demand in the EU-27, Norway, and Switzerland is currently approximately 3500 TWh. Source: Eurostat, EC (2011) and Eurelectric (2013).*

All the scenarios have the same renewable electricity generation (RES-E) shares of gross electricity demand until Year 2020. These shares follow the Member State’s projections reported in the National Renewable Allocation Plans (NREAPs) in Year 2010. After Year 2020, only the Reference scenario and the Regional Policy scenario assume continued and nationally defined targets for RES-E. The RES-E shares of total gross electricity demand are shown in Figure 10.2. For comparison, the model-assessed reference projection presented by the European Commission in December 2013 projects a RES-E share in the EU-27 as a whole of around 50% of the gross electricity demand by Year 2050. This accords with our assumption for the Reference scenario (Figure 10.2, left panel). The EC Roadmap “High efficiency” scenario, which is the inspiration for our Regional

Policy scenario, projects a RES-E share of gross electricity demand of approximately 65% by Year 2050. This is in close agreement with the assumptions we make for the Regional Policy scenario (Figure 10.2, right panel). There are no RES-E targets post-2020 in the Climate Market scenario. This is also the way we have modelled the Green Policy scenario. However, in the Green Policy scenario RES-E instead enters the generation system as a consequence of very stringent CO_2-reduction targets *in combination with* the ruling out of new nuclear power plants and the lack of commercialisation of CCS.

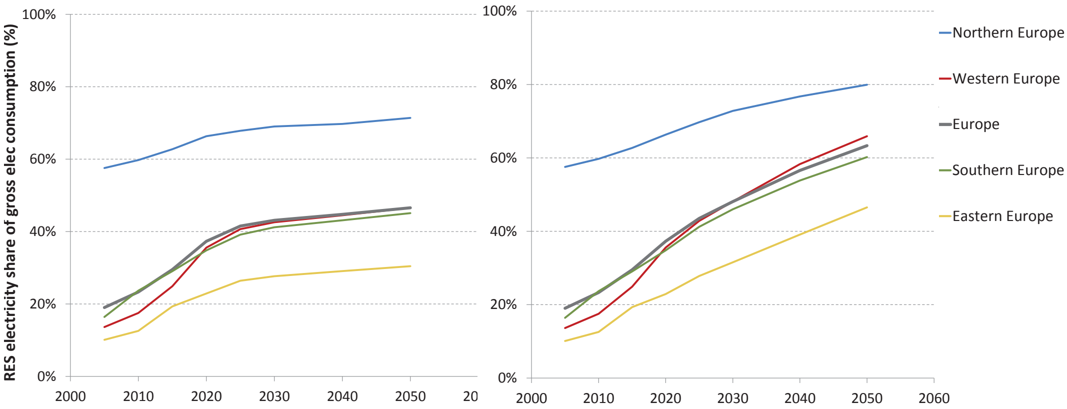

Figure 10.2. *Assumptions regarding RES-E shares of gross electricity demand. The projections until Year 2020 follow the reported National Renewable Energy Action Plans. Left panel: Reference scenario; right panel: Regional Policy scenario.*

The default assumptions for technical lifetimes are 40 years for solid-fuel power plants and 60 years for nuclear power plants (though assumptions differ across countries due to nuclear phase-out policies as in e.g. Germany). This applies to all scenarios with the exception of the Green Policy scenario, for which we assume a shorter lifetime of 45 years for the existing nuclear power plants. Investments in new nuclear power reactors are optional in all the scenarios, except for the Green Policy scenario where no new nuclear power is allowed. The investment potential is assumed to be greater in the Climate Market scenario than in Regional Policy and Reference scenarios.

Our assumptions as to fossil fuel prices follow the assumptions made by the IEA (2013). The model is designed so that fuel prices increase somewhat if demand is sufficiently high and vice versa. When it comes to biomass, this is primarily considered as a domestic (national) resource with many different quality and cost classes. However, at certain price levels, import from outside Europe of biomass for electricity generation is also possible.

The CO_2-reduction targets differ between the scenarios and are reported in the coming sections.

Model results - The Reference scenario

The main goal of the Reference scenario is to analyse the consequences of existing policy instruments. Based on, among others, the reference projection by the EC (2013) mentioned previously, we assume that CO_2 emissions in the European electricity system are reduced approximately 30% by Year 2020, 45% by Year 2030, and 65% by Year 2050, relative to the levels of emissions in Year 1990. This assumably corresponds to a reduction in GHG emissions of 40%–45% for the entire energy system in Europe by Year 2050, as projected by the EC (EC, 2013).

In Figure 10.3, we present two alternative views (but based on the same model results) on the development of the European electricity supply based on the Reference scenario. The left panel shows total production by fuel and source for 1990–2011 based on statistical data, and for 2012–2050 based on the ELIN model results. The right panel shows the production levels, baseed on ELIN model results, between Year 2010 and Year 2050 sub-divided into existing generation and new investments. We conclude (as in the former main section: "Setting the scene") that the supply from existing capacity is rapidly reduced as aging leads to the decommissioning of power plants. Nevertheless, existing capacity will largely affect supply in the coming decades. Owing to the RES-E target, which increases the share of renewable electricity to around 45% of the total gross electricity demand by Year 2050 in the EU-27, Norway, and Switzerland taken as a whole, both the use of wind and biomass grows substantially over time. We have not specifically included the different support schemes that are currently available and that to various degrees promote the use of solar power. This explains the modest share of solar-generated electricity ("other renew" in the left panel of Figure 10.3). CCS (coal) enters significantly into the production system post-2030. New investments in conventional fossil-fuelled electricity generation mainly involve natural gas (CCGT schemes). New nuclear power is not profitable in this scenario, since wholesale electricity prices (see Figure 10.9 in forthcoming section) do not cover the assumed total generation costs of nuclear power, which are approximately 65-70 €/MWh.

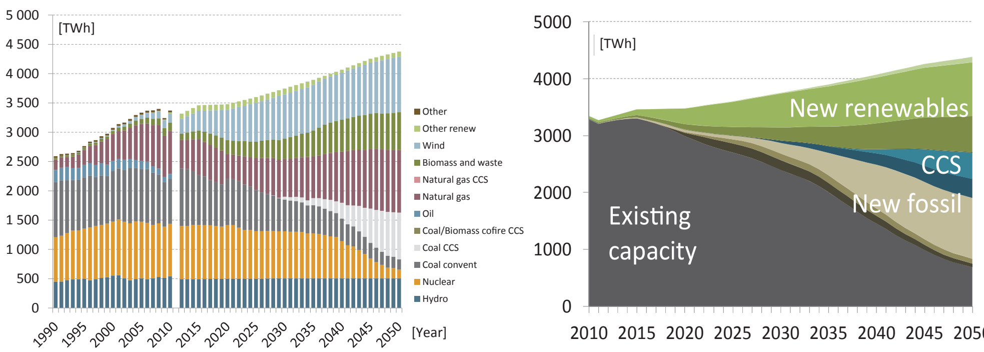

Figure 10.3. *Left panel: Electricity production in the EU-27 plus Norway plus Switzerland, as listed in the Eurostat database for the period 1990–2011 and as projected by the ELIN model for the period 2012–2050 in the Reference scenario. Right panel: Electricity production levels in the period 2010–2050, sub-divided into existing capacity and new generation, based on ELIN model results.*

Model results - The Regional Policy scenario

The Regional Policy scenario includes highly ambitious targets for CO_2-emissions reductions (50% reduction in emissions from electricity generation by Year 2030, and 99% reduction by Year 2050, as compared with the levels in Year 1990), with goals of increasing the share of RES-E and increasing energy efficiency. Thus, this is distinctively a "multi-goal" scenario. Furthermore, the RES-E and efficiency policy targets are met nationally (hence the term "regional"). The Regional Policy scenario is characterised by detailed policy steering, with emphasis on efficiency measures, and it has a national policy view rather than a common European policy-instrument design. Model results are reported in Figure 10.4. In the case of CCS, which becomes profitable post-2040, this consists mainly of biomass-coal co-fired units with a typical co-fire share of 15% biomass. Since CCS is assumed to capture around 90% of the CO_2 emissions while emitting the rest, such co-fired CCS schemes provide the possibility for reaching zero (or even negative) CO_2 emissions.

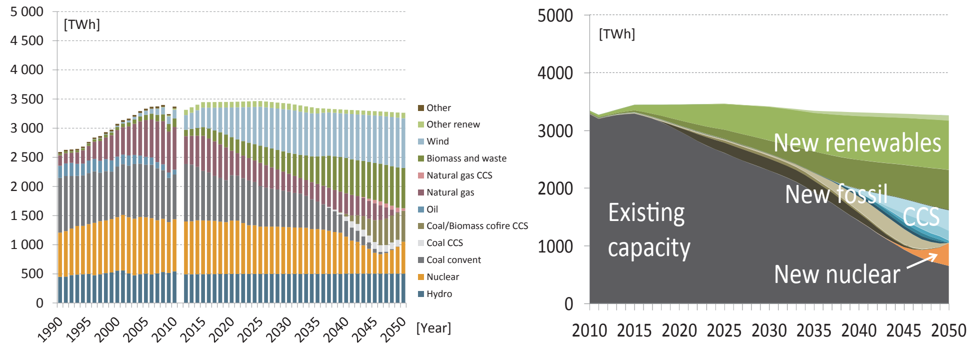

Figure 10.4. *Left panel: Electricity production in the EU-27 plus Norway plus Switzerland, as listed in the Eurostat database for the period 1990–2011 and as projected by the ELIN model for the period 2012–2050 in the Regional Policy scenario. Right panel: Electricity production levels in the period 2010–2050, sub-divided into existing capacity and new generation, based on ELIN model results.*

Model results - The Climate Market scenario

The Climate Market scenario focuses exclusively on climate mitigation post-2020. Thus, this is distinctively a "one-goal scenario". CO_2 emissions from electricity generation are to be reduced by 95% by Year 2050 (50% by Year 2030), as compared to the levels in Year 1990. Since the electricity demand is larger in this scenario than in the Regional Policy scenario, we assume a slightly different balance in CO_2-reduction burden-sharing between electricity generation and the other sectors. In both scenarios, however, we assume a reduction target of at least 80% for the *entire* energy system as defined by the EU Roadmap towards 2050. In the Climate Market scenario, no other policy targets are specified. Thus, this scenario allows "unbiased" competition between all the included supply technologies.

Electricity demand is growing faster than in the other scenarios due to electrification and due to the absence of specific end-use efficiency targets, as in the Regional Policy scenario but also to some extent in the Reference and Green Policy scenarios. Given that electricity is produced with little or no emissions, increased electrification, in for example, transportation, heating, and industrial processes, may in itself be considered as a climate-mitigation measure if it replaces the direct use of fossil fuels in these sectors. The model results are reported in Figure 10.5. All technologies contribute to filling the gap between demand and the existing generation, where the latter declines over time. Significant growth occurs in renewable electricity generation, even though a dedicated RES-E policy is absent post-2020, and CCS also shows growth. The relatively high marginal costs of electricity in this scenario cover also the costs for new nuclear power plants, which implies that nuclear power will generate around 30% more electricity than it does today. In this scenario, there are large new investments in conventional fossil power, mainly in natural gas, until 2040–2045 when the CO_2-reduction requirements make this type of electricity generation unfeasible.

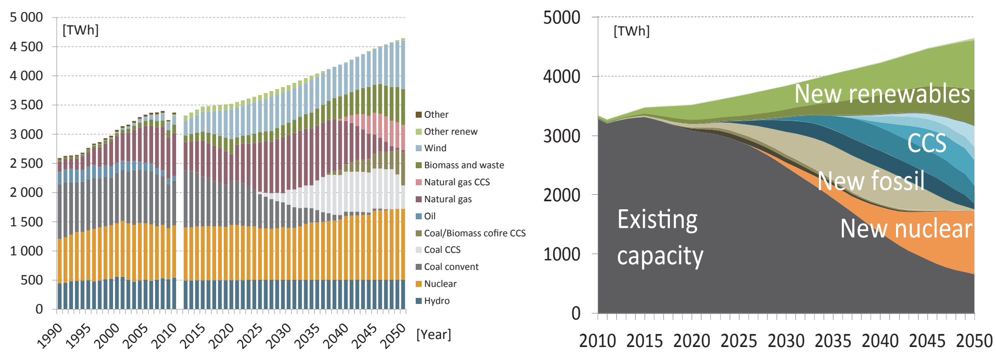

Figure 10.5. *Left panel: Electricity production in the EU-27 plus Norway plus Switzerland, as listed in the Eurostat database for the period 1990–2011 and as projected by the ELIN model for the period 2012–2050 in the Climate Market scenario. Right panel: Electricity production levels in the period 2010–2050, sub-divided into existing capacity and new generation.*

Model results - The Green Policy scenario

As mentioned above, The Green policy scenario is characterised by a very high share of renewable electricity generation in Year 2050. In the model set-up, this is achieved through stringent CO_2-reduction targets for the electricity supply (55% reduction by Year 2030, and 95% reduction by Year 2050, relative to the levels of emissions in Year 1990), and the fact that we rule out both the option of new investments in nuclear power and the commercialisation of CCS. Furthermore, as mentioned above, the expected operational lifetimes of existing nuclear power plants are shorter in this scenario at 45 years, as compared to the other scenarios. The reason for ruling out CCS may be political, technological, or related to public acceptance. The model results for this scenario are shown in Figure 10.6. By Year

2050, wind power becomes the largest supplier of electricity, generating approximately 1300 TWh in Year 2050. We conclude that significant investments in conventional fossil-fuelled (natural gas) generation occur during the entire period until Year 2045, at which time-point the very stringent CO_2-reduction commitments make the use of natural gas without CCS unprofitable.

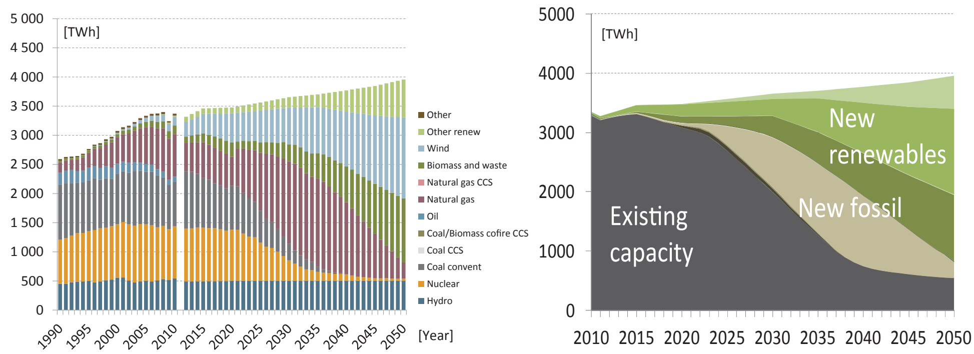

Figure 10.6. *Left panel: Electricity production in the EU-27 plus Norway plus Switzerland, as listed in the Eurostat database for the period 1990–2011 and as projected by the ELIN model for the period 2012–2050 in the Green Policy scenario. Right panel: Electricity production levels in the period 2010–2050, sub-divided into existing capacity and new generation, based on ELIN model results.*

Cross-scenario comparisons – selected results

Hitherto, we have focused on the *production* of electricity in the results reported for the various scenarios. In this section, we take a closer look at selected results and compare them across the scenarios. In Figure 10.7, we present the development of the electricity-generation *capacity* across the four main scenarios. Installed capacity increases in all four scenarios, even in the Regional Policy scenario, in which electricity production declines after Year 2025. This is due to the fact that the supply system increasingly comprises wind and solar power, implying relatively low production-to-capacity ratios. This is also the reason that the Green Policy scenario entails the largest by far capacity build-up of all the scenarios. For such a scenario, the model results indicate that the installed capacity is more than twice as large in Year 2050 than it is today (this is the same magnitude as estimated by the EC in their Roadmap “High RES” scenario). The significant capacity build-up is likely to have significant impacts also on the infrastructure of the electricity transmission and distribution grid.

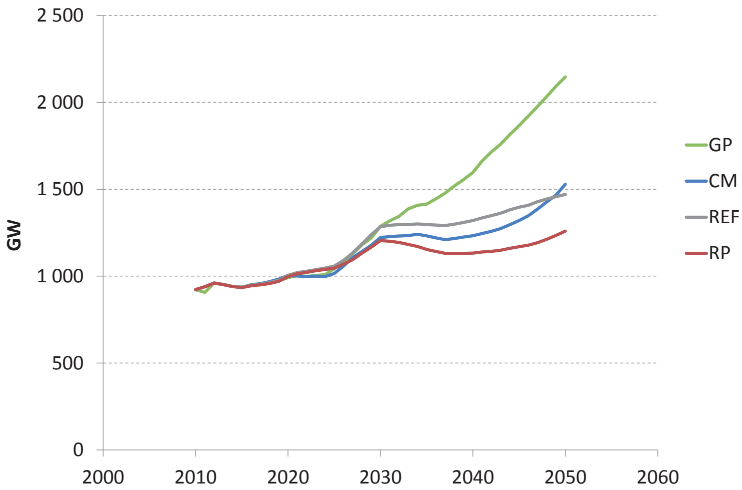

Figure 10.7. *Total installed electricity-generation capacity in the EU-27 plus Norway plus Switzerland in all four main scenarios for the period 2010–2050.*

The marginal costs (MCs) of CO_2 reduction in the European electricity supply are shown in Figure 10.8. This is a model result derived from the predefined reduction cap applied to emissions from electricity generation. Since the cap is common to all European countries, the countries also share the same MC of CO_2 reduction. The figure clearly shows low MCs for CO_2 emissions reductions until Year 2020. This is largely explained by the RES-E targets, which are active in all the scenarios until Year 2020. This further underlines the current situation in the real-life EU ETS market, where low prices are foreseen until Year 2020 (see “Setting the scene” section of this book). The expansion of renewables, mainly with respect to electricity generation, offsets a significant share of the fossil-fuelled electricity generation, entailing a decrease in demand for emissions allowances. Post-2025, the MCs for reductions in CO_2 emissions start to increase in all the scenarios, with the exception of the Regional Policy scenario. Continuation of the RES-E policy and ambitious efficiency policies in the Regional Policy scenario lead to very low MCs for reductions in CO_2 emissions even though the reduction targets are ambitious. It is not until after Year 2035 that the MC for CO_2 reduction increases also in the Regional Policy scenario. The MC curve development in Figure 10.7 is the result of a delicate balance between the three policy targets included in this scenario. In contrast to the Regional Policy scenario, the Climate Market scenario, with comparable trajectories for reductions in CO_2 emissions, exhibits relatively high MCs for reductions in CO_2 emissions already after Year 2020. This is the result of the “one target” policy. All the effort to reduce emissions is put into the carbon market. The MCs for reductions in CO_2 emissions in the Reference scenario level out at around 50 €/tCO_2 after Year 2030. This is a consequence of the significantly less ambitious Year 2050 target, i.e., around 65% reduction in emissions from electricity production by Year 2050, than the corresponding targets in the other three scenarios. The long-term level of 50 €/tCO_2 for the MC corresponds relatively well to the estimates on the EUA price development (covering electricity and additional sectors) made by the IEA (2013) and the EC (2011) in their corresponding reference scenarios. Finally, the Green Policy scenario has the highest MCs for reductions in CO_2 emissions. This is largely explained by the fact that two key technologies are ruled out: CCS and nuclear power. The relatively rapid phase-out of existing nuclear power exerts extra pressure on alternative power production, i.e., through renewables and conventional fossil-fuelled generation. More renewables have to be deployed in the Green Policy scenario than in any other scenario, which means that wind- and solar-power installations with inferior availabilities must be used. Thus, this scenario needs to exploit more high-cost reduction options than the other scenarios, which have a wider array of technologies to choose from. However, the Green Policy scenario could also be defined in an alternative way, including heavy subsidies for renewable electricity all the way to 2050. This would mean a different impact for the marginal costs of CO_2 abatement (we will come back to this further below).

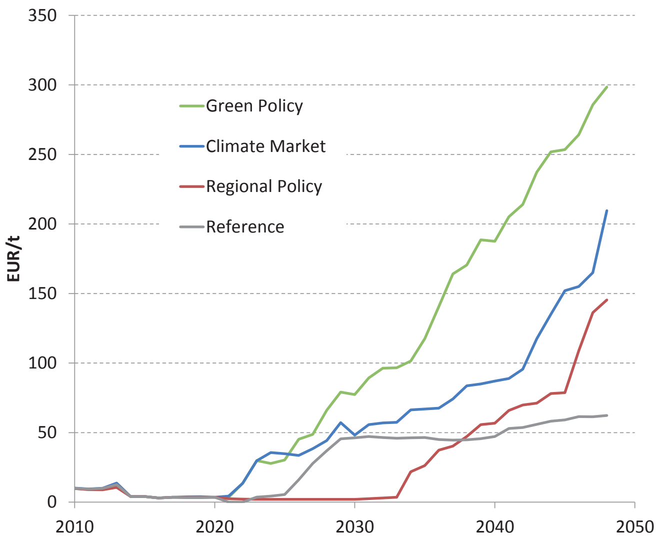

Figure 10.8. *Calculated marginal costs of CO_2 abatement for all four scenarios for the period 2010–2050.*

The MC of electricity generation is a model result that yields important information as to the impacts of the different scenario assumptions. In Figure 10.9 (left panel), we show the MCs of electricity generation for all four scenarios. This indicator is a proxy for wholesale electricity prices and, thus, the income derived from an electricity generator. The MC is calculated as a weighted average (weighted against electricity demand) of the individual MCs of all the countries included in the model. Possible differences between national

MCs for electricity are a result of interconnector bottlenecks. In the figure, the “mean” European MC for electricity is stable at around 40 €/MWh until Year 2020. Despite slowly increasing fossil-fuel prices and increasing pressure to reduce CO_2 emissions, the MC for electricity generation is relatively low. The reason for this is the RES-E target, following the NREAPs of the Member States, which constantly pushes new renewable capacity into the supply system in all four scenarios until Year 2020. This prevents the MC of electricity from increasing. After Year 2020, the MCs for electricity diverge across the scenarios. In the Regional Policy and Reference scenarios, for which we assume continued RES-E support beyond Year 2020, the MCs for electricity are significantly lower than in the two other scenarios. In particular in the Regional Policy scenario, in which we assume the most ambitious direct RES-E support and far-reaching end-use efficiency policies, the MCs for electricity are persistently low until Year 2030. Beyond Year 2040, the MC starts to increase also in the Regional Policy scenario as a result of the very stringent CO_2-emission reduction target. In the Climate Market and Green Policy scenarios, RES-E targets are removed after Year 2020. In the Climate Market scenario, the focus is solely on reducing CO_2 emissions, which rapidly increases the MC for reductions in CO_2 emissions (as previously shown) and thereby also increases the MC for electricity. The Green Policy scenario shares this set-up with the Climate Market scenario, although it makes the CO_2-emission reduction target tougher to meet, since new nuclear power and CCS are non-optional and existing nuclear power is phased out more swiftly. In this sense, the Green Policy scenario might be viewed as a “non-nuclear and non-CCS” policy scenario. Furthermore, considering the fact that the CO_2-emission reduction target is tougher in this scenario until Year 2030 than in the other scenarios (and the same as the Climate Market scenario by Year 2050), it becomes clear that both the MC for reduced CO_2 emissions and for electricity generation are higher in this scenario than in any of the other scenarios. However, the set-up of the Green Policy scenario could also have followed that of the Regional Policy scenario, i.e., specifying a very ambitious target for RES-E until 2050 (i.e., close to 100%, since this is the core definition of the Green Policy scenario). In similarity to the Regional Policy scenario, this would have generated low MCs for electricity generation but, instead, high subsidy costs for RES-E. However, in our case, the close to 100% renewable electricity generation by Year 2050 in the Green Policy scenario is a result of very stringent targets for reductions in CO_2 emissions and the ruling out of nuclear power and CCS, rather than the result of a very ambitious RES-E support scheme.

To reflect the cost of the RES-E target (by Year 2020 for all scenarios and for the Regional Policy and Reference scenarios beyond Year 2020), we have in Figure 10.9 (right panel) calculated a proxy for consumer electricity prices. This consumer-price proxy excludes taxes and electricity-distribution costs but includes the cost of RES-E support. The latter is obtained as a shadow price on the RES-E target in the model results. Thus, we have added the weighted European RES-E “price” (actually, the MC of the RES-E target) to the MC for electricity generation and calculated a weighted mean European “consumer price” of electricity. The European RES-E “price” is calculated as a weighted average across all countries’ individual RES-E ”prices”.

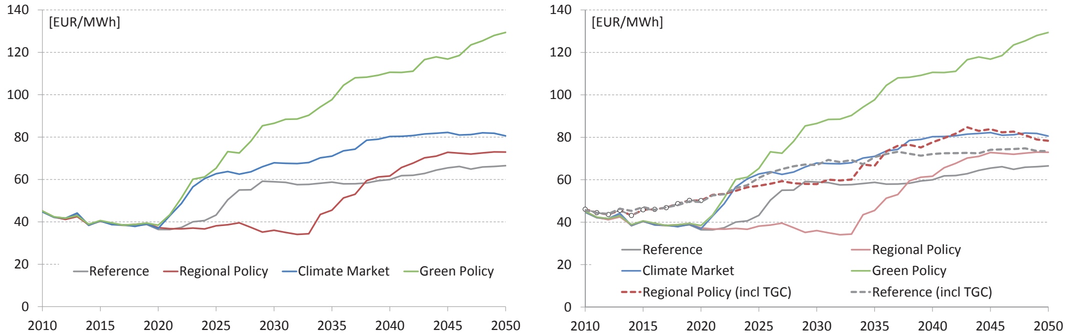

Figure 10.9. *Left panel: Marginal costs of electricity generation in all four scenarios for the period 2010–2050. Right panel: Marginal costs of electricity generation calculated as a proxy for "consumer prices" in the Regional Policy and Reference scenarios for the period 2010–2050 (dashed lines). The curve marked with open circles shows "consumer prices" of electricity for all scenarios until 2020. TGC = Tradable Green Certificates.*

Thus, this might be viewed as a situation in which all countries have domestic tradable green-certificate (TGC) schemes and all the electricity consumers have to pay for that scheme. If only a certain percentage of the consumers are involved, e.g., excluding electricity-intensive industries, the resulting "consumer price" of electricity will be higher for that group of consumers, since the weight of the RES-E price will be higher. Thus, we show in Figure 10.9 (right panel) that the "consumer price" is roughly the same across all the scenarios until Year 2020 (assuming that all electricity consumers are included in the TGC scheme; the curve marked with open circles in the figure). As mentioned earlier, this also applies to the MC for electricity generation. After Year 2020, the "consumer price" diverges from the "wholesale price" (MC for electricity generation) only in the Regional Policy and Reference scenarios, since these two scenarios are the only ones with post-2020 RES-E targets. The "consumer price" in the Regional Policy scenario reaches the same level as in the Climate Market scenario (for which the "consumer price" is equal to the "wholesale price") after Year 2030. Thus, we conclude that RES-E policies are likely to have profound effects on the electricity markets. Wholesale electricity prices will come under pressure and retail prices will increase if RES-E support is transferred to consumer bills.

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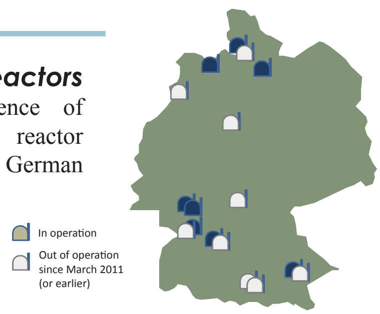
11 The impact of the German nuclear phase-out

In this chapter, techno-economical energy systems modelling is applied to assess the consequences of the decision made by the German government in 2011 regarding the future of nuclear power in that country. The decision was to phase-out all 17 nuclear reactors in Germany at the end of Year 2022, and to shut-down already in Year 2011 eight of the seventeen nuclear reactors that were in operation at that time. This chapter considers both the short-term and long-term perspectives on this issue.

Our analysis indicates that a consequence of taking eight reactors out of operation in 2011 (corresponding to reduction in supply of 60 TWh) is that the increase in short-term marginal electricity cost generally remains at <4 €/MWh in the German electricity market over a calendar year. For certain periods, e.g., during some peak-load situations, the marginal electricity cost increase may however be significantly larger. Unbundled and interconnected electricity markets across Europe lead to cost increases also in the countries neighbouring Germany. However, in these countries such cost increases become less significant than in Germany. In the Nordic market, the corresponding price increase rarely exceeds 3 €/MWh over a year, as compared with a scenario in which all 17 German reactors would have been in operation.

Compared to a reference case in which all 17 German reactors remain in operation beyond Year 2030 (through lifetime extensions), the planned phasing-out by the end of 2022 means that Germany would convert from a significant net exporter of electricity in the long run to becoming a net importer of considerable amounts of electricity. This assumes, however, that no sudden and/or significant capacity deficits occur in Germany's neighbouring countries.

German nuclear reactors



As a direct consequence of the Fukushima nuclear reactor accident in Japan, the German government agreed in June 2011 to finalise a complete nuclear phase-out by the end of Year 2022. Furthermore, eight of the seventeen operating nuclear reactors were shut-down as an immediate response to the Fukushima accident in March, and these reactors have not been brought back on-line. These eight reactors include the seven oldest facilities (commissioned before 1981) and one additional unit that has been out of operation since 2009 (the Krümmel plant, which was commissioned in 1983), with a combined output of about 8.5 GW. The aggregated capacity of the remaining nine reactors is about 12 GW. The figure shows the location of the German nuclear reactors.

Impact on short-run marginal electricity generation costs

Figure 11.1 (left panel) presents the increases in short-term marginal electricity generation costs in Germany, i.e., the difference between the reference case, which includes all 17 German nuclear reactors, and the case in which eight reactors are excluded. The increases in marginal costs over 730 days and nights, i.e., a whole year (model Year 2010) are depicted in decreasing order. It is clear that the increase in marginal cost typically remains at <5 €/MWh. More specifically, for more than 80% of the model year, the increase in marginal electricity generation cost is <4 €/MWh. However, for certain periods, this cost reaches 10 €/MWh (and occasionally it is higher). These model calculations were confirmed suing the actual future prices for 2012 on the German EEX market, which increased by around 5 €/MWh when the eight nuclear power plants were taken out of operation. This increase in generation cost is of less significance for the neighbouring countries due to interconnector bottlenecks. In the Nordic market, represented here by Denmark, the increase in generation cost is <3 €/MWh during 90% of the modelled year (right-hand part of Figure 11.1). For Sweden, the model results indicate that the cost increase is somewhat lower.

In the short-term perspective for a given year, say Year 2012, and with all other factors being constant, the immediate withdrawal of the eight nuclear power plants is compensated by an increase in German coal and gas power production and an increase in net imports of electricity, amounting to around 20 TWh annually. In reality, since the closure of reactors at the beginning of 2011, renewable electricity generation has expanded significantly in Germany. In the period 2011–2012, the increase in renewable electricity generation was around 40 TWh, which more than compensates for the model-estimated net import of 20 TWh given that no additional generation capacity was added. Thus, Germany is currently a net exporter of electricity, even though approximately 60 TWh of nuclear power has been taken out of operation since Year 2011.

Limited impact on long-run marginal costs

Despite the fact that all the nuclear reactors in Germany are to be taken out of operation by the end of Year 2022 (corresponding to a total loss in production of around 150 TWh), the model-estimated increase in long-term marginal cost of electricity in Germany after 2020 is relatively small, at 2–3 €/MWh. Possible explanations for this are the assumed commercialisation of CCS and the fact that this technology sets the long-term marginal cost for new power post-2020. The withdrawal of other capacity, in this case nuclear power, is replaced by additional CCS, which implies a limited impact on the long-term marginal costs of electricity. Before Year 2020, the nuclear phase-out is, as indicated above, mainly covered by an increase in gas power (and a reduction in coal power, so as to meet the CO_2-emission reduction target). In the short-to-medium term perspective, there is considerable "idle" capacity of gas power in the EU-27, which could replace a large part of the gradually phased-out nuclear capacity in Germany. Furthermore, new interconnectors may be built endogenously in the model as a response to the German nuclear phase-out,

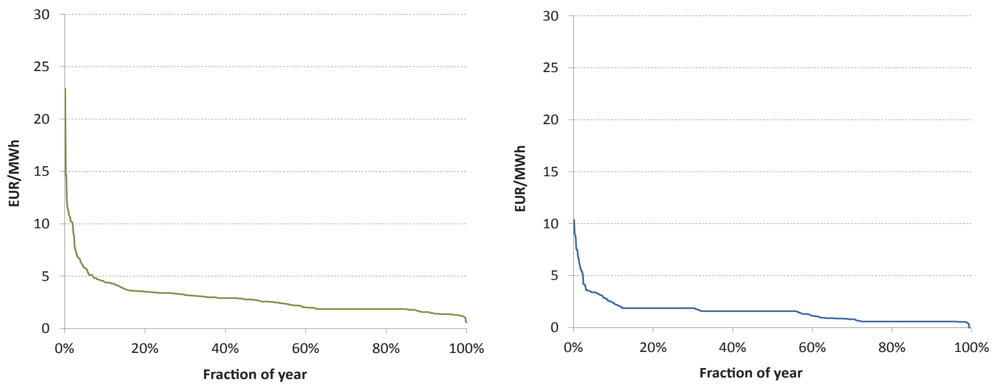


Figure 11.1. *Modelled increase in short-term marginal costs during the modelling years in Germany (left) and Denmark (right). Cost increases are arranged in decreasing order.*

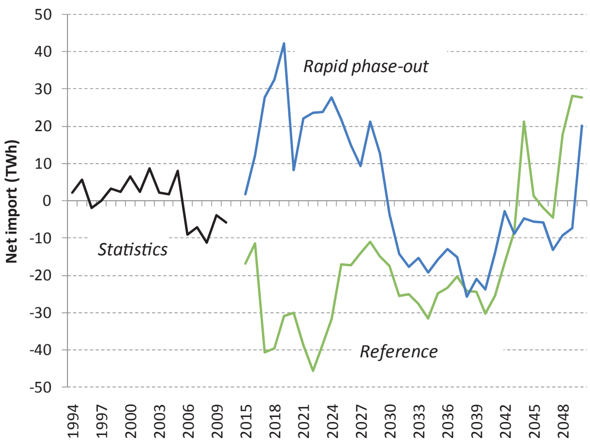


Figure 11.2. *Long-term impact of phasing-out nuclear power on German net electricity imports (trade with Switzerland excluded), as obtained from the modelling in this work.*

thereby further integrating the European electricity markets. In this manner, the increase in the long-term marginal cost of electricity in Germany is spread across Europe and its impact is thereby dissipated. In the context of an integrated European electricity market, the total German operational nuclear generation capacity is relatively small, accounting for roughly 5% of the total European electricity generation. The corresponding increase in marginal CO_2-reduction cost, which is a proxy for the price of European tradable emission rights, obtained in the model runs is approximately 1–3 €/tCO_2.

Estimates of increases in the wholesale price for electricity associated with a complete nuclear phase-out in Germany differ significantly between various studies. For instance, the Umweltbundesamt (2011) estimates price increases of 6–8 €/MWh for electricity and 2–4 €/tCO_2 for the EU-ETS, while R2B Energy Consulting GmbH (2011) reports corresponding estimates of 11–16 €/MWh for electricity and 5–10 €/tCO_2 for the EU-ETS. Both these studies assume completion of nuclear power phase-out in 2017, which is a more stringent goal than phase-out by the end of Year 2022, as assumed here. If the same phase-out deadline had been applied in the present analysis, this should generate somewhat higher price increases, all other factors being identical. A more recent study conducted by EWI (2012) suggests that the increase in wholesale electricity prices due to the phase-out of nuclear power corresponds to a cost of around 5 €/MWh by 2015 and almost 10 €/MWh by 2030. The same study assumes an increase in the EUA price of around 1–2 €/tCO_2.

Future impact on the German electricity-trade balance

The nuclear phase out results in a significant change in the German electricity-trade balance with its neighbours. In Figure 11.2, net electricity import to Germany is shown for both cases investigated, the reference case and the "Rapid phase-out" case. In the reference case, Germany becomes a significant net exporter, typically 25 TWh around 2020-2025. This is due to a continued expansion in the field of renewables, investments (and comparative advantages) in CCS schemes and, not the least, the full utilisation of the 17 nuclear reactors. At the same time, domestic demand is stagnating. In the "Rapid phase-out" case, on the other hand, Germany instead becomes a significant net importer of electricity, typically 20 TWh around 2020-2025. Thus, the short-fall of around 150 TWh of domestic production is met by an almost 50 TWh increase in German net import. The rest is supplied domestically.

Final remarks

The analysis presented here makes a number of important assumptions which may underestimate the impact of the German nuclear phase out. One of these important considerations is that CCS becomes commercially available from 2020 and onwards. Thereby, nuclear baseload power may be replaced by another means of generating low-emitting baseload power. If CCS fails in becoming commercially available, or is substantially delayed, other types of baseload power must be used, e.g. conventional fossil power which most probably would lead to a more significant impact on EU ETS prices than estimated here. Furthermore, the model approach used here permits unlimited interconnector investments. Thus, the impact on the German electricity market becomes geographically spread and diluted. Limiting the analysis to existing interconnectors is likely to increase the impact in the German electricity market (and probably reduce impact on neighbouring markets) compared to what has been reported here. A supplementary model run indicates that such limitations (new interconnectors and a later commercialisation of CCS) have an impact especially on the marginal CO_2-reduction cost. In such a case, a cost increase of around 7 €/tCO_2 was obtained as compared to the 1-3 €/tCO_2 in the reference case. Accordingly, the marginal electricity cost increase was roughly one €/MWh above the outcome in the reference case.

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12 Abundance of natural gas and its implications on electricity supply

This chapter presents an assessment of the natural gas market with implications on the European stationary energy system (mainly electricity generation) over the next decades, considering the good prospects for future supply of natural gas, the recent slow down in development and higher initial cost for CCS, and uncertainties with respect to a global post 2020 GHG emission regime. We call this development "Gas Abundance and Delayed CCS", which is investigated for a relatively high growth scenario with respect to electricity demand. The tools for the analysis are an assessment of the global gas market and application of a cost minimising energy systems model (the ELIN model). In the scenario investigated, natural gas consumption in the European (EU-27, Switzerland and Norway) power sector increases from 181 bcm in 2010 to a peak of 305 bcm in 2030. The main conclusion is that abundance of gas can provide mid-term emission cuts taking the strain off the requirement of early employment of CCS.

Following the Conference of the Parties (COP)17 in Durban and COP18 in Doha, there remain significant uncertainties with respect to the envisaged global post-2020 GHG emission mitigation regime. In addition, the prices for emission allowances within the European Emission Trading Scheme (EU-ETS) have remained low, and it is likely that these prices will remain below 20 €/tCO_2 in the period leading up to Year 2020 (EC, 2012). This will obviously weaken the incentive to develop carbon capture and storage (CCS) systems.

In recent years, it has become clear that substantial resources of conventional gas together with potentially significant resources of unconventional gas could lead to natural gas becoming increasingly competitive, thereby underpinning a large expansion in gas-based power, without compromising the security of supply. At the same time, it has been proposed that one of the key mitigation options, CCS, will require large up-front investments, and that CCS may not reach commercial maturity until well after 2020, considering the lead times for development and the requirement for large upfront investment, as well as the above-mentioned uncertainties associated with post-2020 climate mitigation policy. Moreover, the construction of new coal plants and CCS are facing considerable opposition in some member states. Therefore, the rate at which CCS will be deployed is uncertain, and it seems highly unlikely that CCS will be commercially available by Year 2020.

In light of this situation, it is of interest to investigate a future that takes into account relatively strong prospects for the future supply of natural gas and in which higher initial costs (or other barriers) for CCS lead to a less rapid deployment of CCS than was previously anticipated. This work examines these issues through an assessment of the global gas market and the ELIN model, which uses the Chalmers energy infrastructure database as an input. We refer to this situation as one of *"Gas Abundance and Delayed CCS"*.

Scenario assumptions

The setup for the scenario is chosen based on the results of an initial analysis, from which it was concluded that a scenario with a growth rate similar to that of the Climate Market scenario is required in order to pose challenges to the existing supply and supply infrastructure of gas. Thus, two versions of the Climate Market are used: 1) the original Climate Market (CM) as a reference case; and 2) CM-2, with a gas price to coal price ratio of 2. In brief, the CM-2 scenario is used to explore the following question: *"How large can the demand for natural gas in the electricity sector become if the gas price to coal price ratio is maintained at a low level over the long-term?"*

Results from the modelling

This section gives the results of the modelling. The results of the assessment of the global gas market can be found in Chapter 2. The latter analysis serves as the basis for several of the inputs adopted during the modelling.

Figure 12.1 (left panel) shows the development of the European power generation system, as obtained from the modelling of the reference case (CM). It is clear that the level of generation of current power plants (represented by the large pale-hued area at the bottom of the figures) will remain an important component of the system for decades to come. Since the CM scenario includes stringent CO_2 emission reduction targets for the power sector, i.e., 30% by Year 2020 and 93% by Year 2050 (relative to the levels in Year 1990), there is a driving force for the replacement of old coal-fired power plants with natural gas-fired power plants. However, towards the end of the modelled period, the emissions cap becomes very tight and other measures that have low carbon intensities are required for the system to comply with the cap. Here, the main options are CCS, nuclear power, and the use of renewables. For the investigated scenarios, there are no RES policies after 2020, which means that the model selects wind and biomass power based on competitiveness, which includes the effects of the obtained carbon prices that result from the designated cap. From Figure 12.1 (left panel), it can be concluded that CCS is a key technology for the long-term prospects of CO_2 abatement through power generation, especially if electricity demand continues to rise along historical trends, as in the scenarios investigated here.

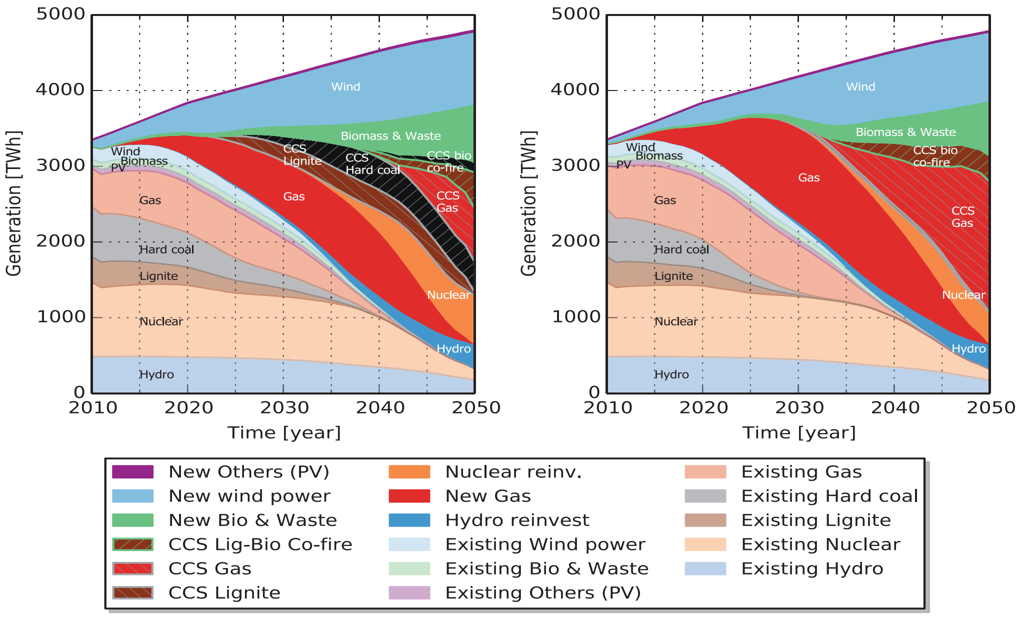

Figure 12.1. *Development of European electricity generation for the EU-29 (EU-27 plus Norway and Switzerland) countries, as obtained from the modelling of the CM scenario (the reference scenario, left), and the CM-2 scenario (right). In the CM-2 scenario the gas price to coal price ratio is fixed at 2, which is assumed to reflect abundant gas supplies to Europe (bottom panel). The pale-hued area in the lower part of the figures represents the levels of power generated by current power plants (taken from the Chalmers power plant database).*

Figure 12.2 provides the marginal costs for electricity generation and CO_2 abatement, for the system described in the left panel of Figure 12.1. The evolution of the marginal cost of electricity generation suggests that electricity prices roughly double over the period studied, and that price differences between member states increase (grey area in Figure 12.2). It is also clear from the figure that CO_2 prices must exceed approximately 30 €/tCO_2 for CCS to be implemented, given the costs applied in this work.

The exponential nature of the marginal abatement cost curve poses some challenges to the demonstration of CCS, i.e., substantial CO_2 abatement can be achieved by conventional fuel shifting from coal to gas, i.e., at a cost that gives few or no incentives to build CCS. However, when the emission reduction due to fuel shifting is "used up", CCS needs to be sufficiently mature to be the marginal measure of emissions reduction; failure to demonstrate and develop CCS to meet the costs applied in the present work will necessitate much more expensive measures. Towards the end of the period, the marginal cost will be 100–200 €/tCO_2, although this is sensitive to the development of technology costs and technology availability. These high costs can in part be explained by the fact that some capacity is prematurely shut down, i.e., many gas power plants are still in place but cannot be used due to the emissions cap. Thus, the high CO_2 cost reflects this "lost value". Finally, it should be noted that high prices at the end of the period should be considered in the context that the total emissions are low, and thus do not reflect significant financial value in absolute terms.

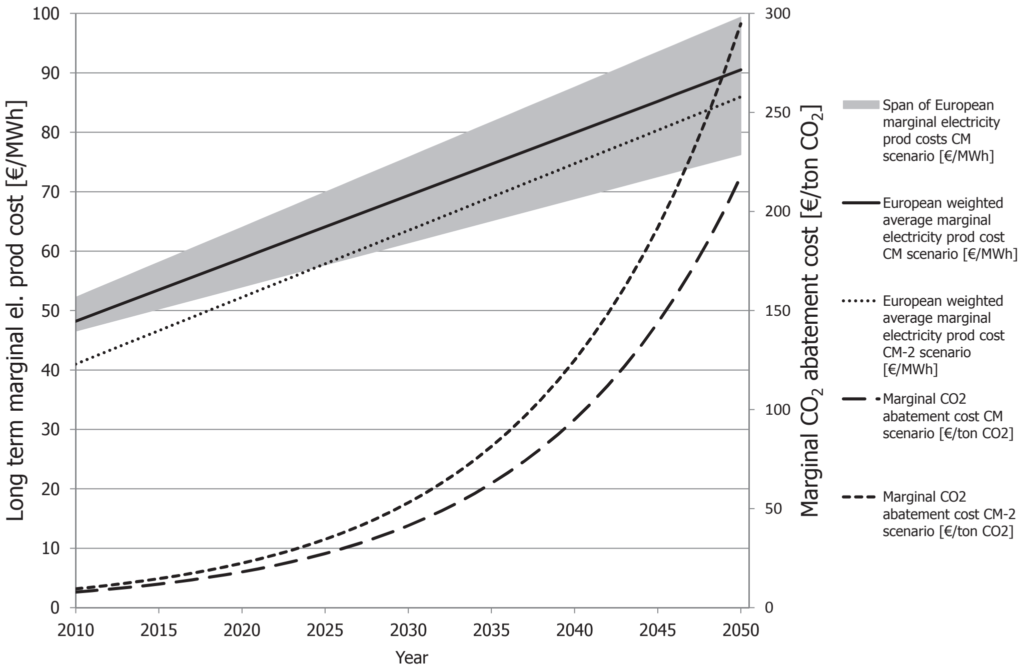

Figure 12.2. *Marginal cost of electricity generation and marginal cost of CO_2 obtained from the modelling for the CM scenario and the CM-2 scenario. The corresponding cap, which determines the marginal abatement cost, is 30% by Year 2020 and 93% by Year 2050 relative to the emissions levels in 1990, implemented as annual caps that are linearly reduced.*

Figure 12.1 (right panel) reveals the development of European electricity generation in the CM-2 scenario, i.e., in which gas prices are fixed to the price of coal multiplied by a factor of two. This fuel to price ratio is maintained throughout the modelled period and describes a long-term abundance of gas. This increased competitiveness of natural gas points to strong expansions in gas power, also in the longer-term perspective, since gas CCS technologies can compete with at least hard coal CCS for gas price to coal price ratios of less than 2.5. Furthermore, an abundance of natural gas could reduce the strain of meeting CO_2 emission targets by low-cost fuel shifting from coal to gas, with the consequence that CCS would be delayed to after 2030 and then limited to gas CCS and zero net emissions lignite

CCS (employing co-combustion of biomass to offset anything below 100% capture). An obvious problem in such a case is whether society (political systems) will maintain the development of coal CCS technologies so that they are competitive when needed later in the period. The present pattern of development indicates that this will be problematic.

The supply of low-cost gas could also affect the competitiveness of reinvestment in nuclear power, which is lower in CM-2 than in CM. The marginal costs for electricity and CO_2 abatement in the CM-2 scenario are obviously lower, although not significantly different from those in the CM scenario (see Figure 12.2).

Remarks on the near term development

The work in the present study indicates a positive trend for gas-based power generation, especially in the mid-term until Year 2030. However, current trends in the power sector indicate decreased use of and mothballing of gas power plants. These apparently contradictory trends can be explained by several factors. The "abundance of gas" investigated in the present study in terms of the current situation and in the nearest five to ten years refers primarily to the situation of gas abundance in the USA, which has led to increased use of gas in the USA and as a consequence, lower consumption of coal (EIA, 2012). This has in turn led to highly competitive coal prices on European markets. At the same time, the economic situation in Europe has produced stagnation (or even a decrease) in electricity demand, which in combination with the current ambition level within the EU ETS, has resulted in the over-allocation of emission permits and consequently, low prices for EUAs.

In addition to the poor competitiveness of gas relative to coal, low prices for emission permits provide little incentive for new investments in forthcoming technologies, such as CCS. However, after Year 2020, provided that the EU pursues a course in line with the stated targets for long-term stabilisation with a temperature increase of approximately 2°C, substantial emission cuts will be required. Thus, it is questionable whether the pace of capital stock turn-over can be accomplished if the transition is postponed much later than 2025. From the perspective of an investor, the current uncertainties with regard to the ETS and fuel markets leave few options for installation of new capacity. One possibility, which is supported by other model runs within the Pathways research programme, is that the only secure investment at present is life-time extensions of old coal-fired power plants, although this prolongation should not continue past Year 2020. However, this option may be offset by any update of the EU ETS. Furthermore, as it stands today, a large part of the operational coal plant stock is scheduled for shut-down by January 1st, 2016 at the latest due to the Large Combustion Plant Directive (LCPD). According to, for instance, the EEA (European Environment Agency, 2013), coal and oil plants with thermal capacities of about 100 GW are eligible for shut-down by 2016 in line with the LCPD. The LCPD is followed by the Industrial Emission Directive (IED), coming into effect on January 1st, 2016 and setting even stricter emission limits, which will lead to more coal plants being shut down in the period 2016–2023. Another possibility is investments in renewable energy in regions with support schemes that are sufficiently robust to ensure a reasonable return. Moreover, the rather slow pace of change in the power system may promote additional regulatory/policy/support measures, such as re-regulation in the UK, emission performance standards, and floor-prices in the ETS. However, the present study and other model runs within the Pathways research programme indicate that the present complementary targets for 2020 will ensure low EUA prices past Year 2020. Thus, any additional policy measures that do not involve adjustment of the ETS could lead to increased interference between measures, with the risk of zero prices for carbon as a consequence.

In summary, there are significant uncertainties associated with the present electricity sector in terms of investments in new plants, with certain parameters favouring coal (i.e., low EUA prices and low coal prices) in the near-term but favouring gas in the medium-term. In addition, a real transformation of the system must be initiated in order to achieve GHG emission cuts of more than 20% (relative to the levels in 1990).

Conclusions

The modelling exercise allows us to draw the conclusions listed below.

1) In the medium term it appears that:

   a. Natural gas is a serious competitor for CCS;

   b. Limitations in CO_2 emissions from electricity generation will benefit fuel shifting from conventional coal to gas CCGT.

2) Natural gas can provide medium-term emission cuts, thereby reducing the pressure for early employment of CCS. Competitively priced natural gas (as in a natural gas abundance scenario) may further support this trend.

3) Recent updates as to the costs of technology and primary energy (relative to earlier work within the Pathways research programme) indicate an increase in the competitiveness of gas power, in contrast to the situation observed during 2012 when coal prices were significantly more competitive than gas prices.

   - However, it is important to note that increased marginal costs lead to greater employment of biomass and wind power (relative to the previous work)

Compliance with the EU Energy roadmap, which cites a 93%–99% CO_2 emission reduction up to Year 2050 (relative to level in Year 1990), will require CCS with “zero”-emissions. Yet, even though gas CCS in the study is not of “zero”-emission type it is an important CCS option prior to Year 2050, yet from a competitive point of view compared to coal CCS dependent on gas to coal price ratios. In the long run approaching strict CO_2 limitations it is not clear how long non-“zero”-emission CCS can be maintained as base-load.

Combining these conclusions with those from the assessment of the natural gas market (see Chapter 2), we can state that:

4) Of the scenarios investigated here, the CM-2 scenario is the only one that poses a challenge to the existing supply and infrastructure of gas. This is due to the dramatic increase in demand for natural gas. In the CM-2 scenario, gas consumption in the power sector in the EU increases from 181 bcm in Year 2010 to a peak of 305 bcm in Year 2030, with almost the entire increase occurring between Years 2020 and 2030. For the CM-2 scenario, we conclude that:

a) The increase in gas consumption is not critical with respect to supply, although it is assumed that Norway's production is declining, which implies that the EU will become more dependent on imports from other suppliers.

b) Increased consumption of gas by the power sector alone should not pose any challenges up to Year 2020 with respect to current supply capabilities, including import capacity that is in operation and under development.

c) Up to Year 2020, the increased consumption of gas in Poland may impose a challenge to energy security, as this will entail increased dependency on imports from Russia, while at the same time Poland is working to reduce this dependency by building an LNG terminal. Consumption of gas by Poland's power sector increases from 1.3 bcm in Year 2010 to 8.2 bcm in Year 2020. Total gas consumption in Poland in Year 2010 reached 17.2 bcm.

d) To a certain extent, the situation described for Poland also applies to Finland, where consumption more than doubles during the same period, from 2.6 bcm to 5.3 bcm.

e) Some of the modelling results go against current trends in EU. For example, gas consumption in the power sector of the Netherlands declines from 18.3 bcm in Year 2010 to 11.9 bcm in Year 2020. Similarly, in the UK, gas consumption in the same period declines from 33.6 bcm to 24.8 bcm.

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13 The Nordic countries as an export region of renewable electricity

In a climate policy-oriented Europe, it is likely that the value of the Nordic electricity supply system will increase. The fossil fuel share of the existing supply is very low in the European context, accounting for less than 15% of total electricity production. Investments in new CO_2-lean or CO_2-free capacity are favourable in the Nordic countries compared to other European countries due to an abundance of renewable resources, such as wind, biomass and, in Norway, hydropower. The important part played by district heating in the Nordic heating markets enables efficient electricity production through combined heat and power schemes. Although the long-term future of nuclear power in the Nordic countries is highly uncertain, near-term developments point to increasing capacity through the commission of the fifth nuclear power reactor in Finland (due in 2016) and through ongoing repowering investments in parts of the Swedish nuclear power fleet. As electricity demand in the Nordic countries is predicted to stagnate or only slightly increase, there is strong potential for increased exports of Nordic electricity. Thus, in a European context, increased exports of Nordic CO_2-lean electricity would represent a cost-efficient step towards meeting the goals of European climate policy. However, before this potential can be realised, several preconditions have to be fulfilled, including increased interconnector capacity to continental Europe and increased transmission capacity in continental Europe, especially Germany. Furthermore, the policy instruments currently in force, especially the EU ETS, must deliver substantial price signals to enable the necessary investments. This would require a significant change in direction for the current emission market.

Nordic electricity production

Nordic electricity production is characterised by a very low share of fossil-fuel combustion. Less than 15% of the total electricity supply is produced in coal-, oil-, or gas-fired power plants. This share is projected to decline further over the coming years and to approach zero around Year 2030, assuming that current policy measures stay in place and that the EUA price starts to climb from its currently very low level. Figures 13.1–13.3 show calculations (from the MARKAL-NORDIC model[1]) for the Nordic electricity supply between Years 2010 and 2050 for three different policy scenarios. The reference scenario assumes a

[1] The MARKAL model framework was developed in a cooperative multinational project over a period almost two decades by the Energy Technologiy Systems Analysis Programme (ETSAP) of the International Energy Agency (see more at www.iea-etsap.org). The MARKAL-Nordic model is described in Unger (2003).

moderate European climate policy that follows the EC PRIMES baseline projections from 2013. This corresponds to a reduction of European GHG emissions of around 40% by Year 2050. In this scenario, the overall electricity production in the Nordic countries increases slowly. Investments are made, mainly in renewables, as a result of the current support schemes, i.e., electricity certificates in Sweden and Norway, feed-in tariffs in Finland, and premium tariffs in Denmark. Nuclear power capacity increases as a result of new investments in Finland, with a fifth reactor and a sixth reactor being commissioned during this period, and the repowering of parts of the Swedish nuclear power fleet. Net electricity export from the Nordic countries (the difference between the bars and the line in Figure 13.1) is relatively high, typically at 20–30 TWh annually. The analysis includes only trade with continental Europe and not trade with Russia or potential trade with the UK.

In Figures 13.2–13.3, the Nordic electricity production is the result of stringent European climate policy following the EC Roadmap ambitions to reduce GHG emissions by at least 80% by Year 2050. However, the policy instruments used to reach that goal are different in the two scenarios (the scenarios differ also concerning the electrification of transport and industry, which affects electricity demand). In Figure 13.2, policy is focused on reducing GHG emissions, resulting in a high price for carbon and consequently, high prices for electricity in the wholesale and retail markets. This stimulates new investments in the Nordic countries. New nuclear power is assumed to be profitable under such circumstances. In contrast, in Figure 13.3, the European climate policy goal is achieved through a palette of measures that involve also targets for renewables and energy efficiency. This resembles the current situation, as exemplified by the EU 20-20-20 policy target for Year 2020 and thus, the previous Reference scenario. However, in Figure 13.3 (a variant of the Regional Policy scenario described in a previous chapter), we expect such a “three-goal” setup to be further intensified and to be extended beyond Year 2020. Reduced electricity demand, achieved through the efficiency policy, and a substantial increase in renewable electricity generation, achieved through support schemes, mean that the price of carbon (the EUA price) is substantially lower than in the former case, ensuring that wholesale prices for electricity remain low. However, retail prices for electricity increase, since the support for renewables is assumed to be financed through consumer electricity bills. Thus, in this scenario, new investments in nuclear power are not profitable. As nuclear power is phased-out, the Nordic oversupply is reduced. However, thanks to generous support for renewable electricity, the capacity balance remains positive. In a Reference scenario in which a nuclear phase-out is assumed, the model results indicate that the capacity balance would be much narrower and possibly entail a long-term dependence on net imports. In both scenarios in Figures 13.2 - 13.3, the Nordic net electricity export is of significant magnitude and clearly exceeds the corresponding outcome of the Reference scenario reported in Figure 13.1.

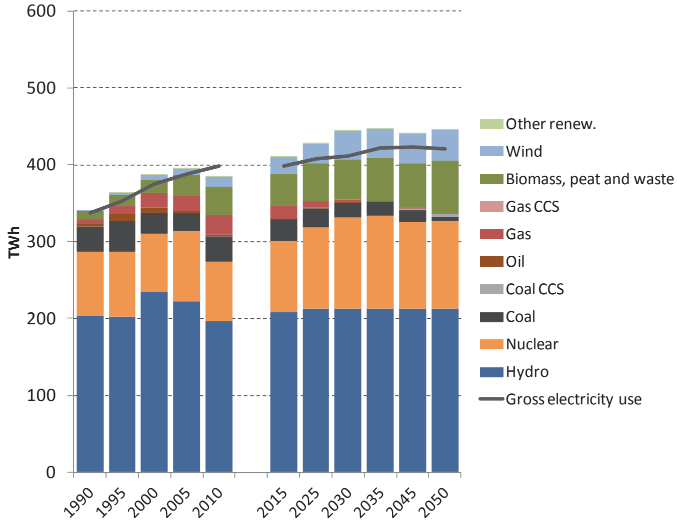

Figure 13.1. *Nordic electricity supply in a reference scenario with moderate European climate policy targets. The grey line indicates the gross electricity consumption in the Nordic countries.*

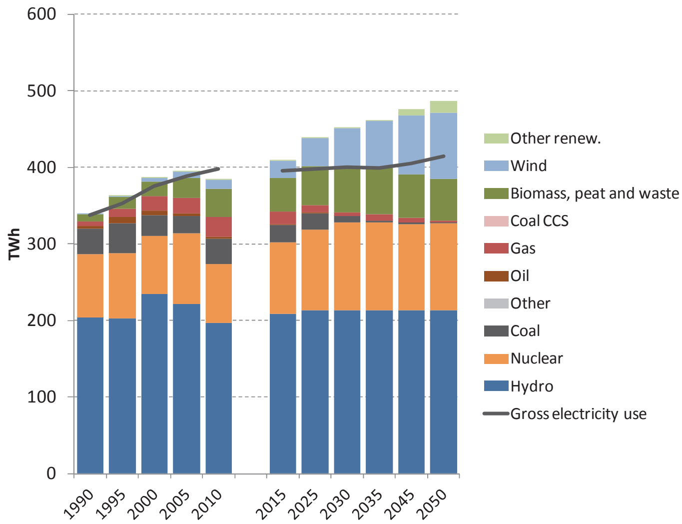

Figure 13.2. *Nordic electricity supply in an ambitious European climate policy scenario with the focus on reductions in GHG emissions (Climate Market scenario variant). The grey line indicates the gross electricity consumption in the Nordic countries.*

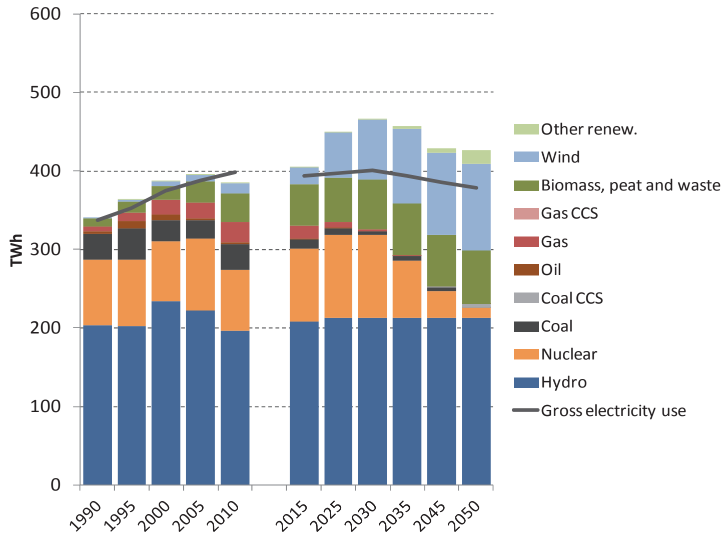

Figure 13.3. *Nordic electricity supply in an ambitious European climate policy scenario with the focus on reductions in GHG emissions, increased use of renewable energy, and increased energy efficiency (Regional Policy scenario variant). The grey line indicates the gross electricity consumption in the Nordic countries.*

Potential for substantial net electricity export

In the previous section, we concluded that development of the Nordic electricity market is likely to enable a substantial net electricity export to continental Europe. Historically, the Nordic net electricity export to continental Europe (Germany, Poland, the Netherlands, and Estonia) has generally not exceeded 10 TWh. Based on the available statistics, 2012 was a record-breaking year, with net export of almost 20 TWh of electricity. In Figure 13.4, it is evident that the net electricity export varies significantly between years, mainly due to variations in precipitation and consequently, in hydropower production. According to the same figure, the model results indicate that around 70 TWh could be net exported from the Nordic countries after Year 2030 if conditions are favourable. However, a number of important preconditions must be fulfilled if this is to be realised. That the potential for Nordic net electricity export is very strong in a climate policy-oriented Europe has also been confirmed by energy systems modelling performed by the IEA and Nordic Energy Research (2013).

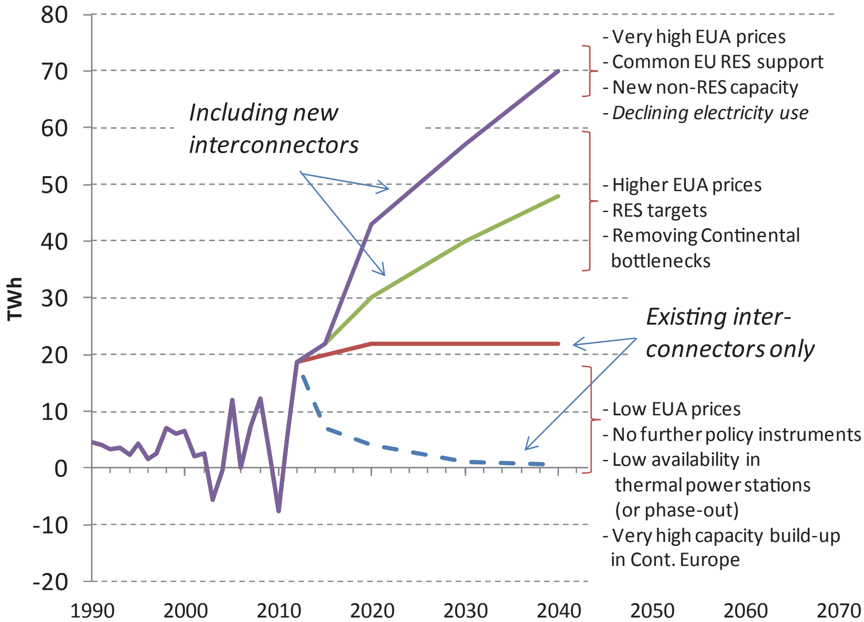

Figure 13.4. *Net electricity exports (in TWh) from the Nordic countries to continental Europe (Germany, Poland, the Netherlands, and Estonia) historically and as estimated by the model study reported here. Source: 1990-2012: ENTSO-E and Nordel.*

The driving forces required to exploit a substantial Nordic net electricity export include:

- Differences in the existing and new supply structures between the Nordic countries and continental Europe, leading to long-term marginal-cost differences.
- An ambitious European climate and renewables policy. As the EU ETS price increases, the more competitive Nordic electricity generation becomes. This is also true for a large share of the fossil-fuelled electricity supply, since it consists mainly of relatively efficient combined heat and power schemes in the Nordic countries.
- A common European renewable electricity target is likely to imply a greater need for exports of Nordic electricity than if renewable targets are only to be met domestically. A common scheme means that countries that have high marginal costs for renewable electricity generation need to produce less than they would otherwise in exchange for the countries with lower costs, presumably the Nordic countries, taking on a larger share of the renewable electricity production.
- Increased importance of cross-border power/capacity trade. This may have an impact on the dispatch of hydropower (see Chapter 20).

Apart from the above-mentioned driving forces, a number of important preconditions must also be considered for a large (>20 TWh) Nordic net electricity export to take place by the period 2020–2030:

- New interconnectors must be built that have relatively short lead times.
- Maintenance and upgrading of nuclear power. Phasing-out non-renewable electricity generation will reduce the potential for net electricity export.
- Public acceptance of increased electricity production in the Nordic countries for the benefit of the European electricity system. A significant increase in the exploitation of wind resources, for example, will probably not happen without local intervention.
- Domestic grids must be reinforced. This involves the Nordic countries as well as the new transmission capacity in continental Europe. New transmission investments are needed, especially in Germany, in order to transmit Nordic electricity in southern directions. Currently, there are significant north-south transmission bottlenecks within Germany. North Germany is currently an area of electricity oversupply, which implies that Nordic electricity exports may be dampened (see more on this topic in Chapter 20).

Finally, the potential for net export may be further boosted by reduced electricity demand in Northern Europe.

New and existing interconnectors

Investments in new interconnector capacity between the Nordic countries and Continental Europe have been estimated to around 4-5 GW by 2025 using the MARKAL-NORDIC model in an ambitious climate-policy regime. Total existing interconnector capacity available for Nordic export is around 4.2 GW (see Figure 13.5). Thus, we are talking about a doubling within 10 years which might be overoptimistic considering the long lead times for new interconnectors. If the existing cables could be fully utilised the potential for exporting from the Nordic countries amounts to roughly 35 TWh. However, due to e.g. domestic grid limitations, reserve margins and maintenance and interruptions , the capacities are not fully utilised. The maximum flow (adding import and export to and from the Nordic countries) through these interconnectors have, hitherto, been approximately 20 TWh per year (ENTSO-E statistics). However, interconnector capacities between the Nordic countries and Continental Europe also have to consider annual variations in precipitation leading to significant variations in hydro power and, thus, in total Nordic electricity production. This is also an important reason why the interconnector capacity may seem somewhat “underutilised”, at least during normal year conditions.

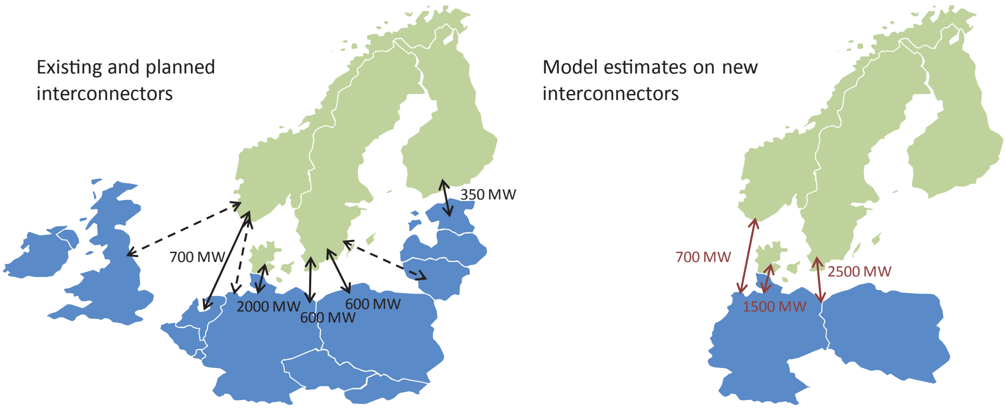

Figure 13.5. *Left panel: Existing interconnectors (transmission capacity in MW) between the Nordic countries and continental Europe (excluding Russia) and planned new interconnections (dashed lines). Right panel: New interconnectors between the Nordic countries and Continental Europe, as estimated by the MARKAL-NORDIC model by Year 2025 with an ambitious European climate policy regime.*

Final remarks

The increase in net electricity exports from the Nordic countries indicates that the expansion of renewable electricity generation poses a significant challenge for the transmission system operators. The description of the system for Year 2020 shows increased transit, particularly through Sweden and Denmark, increased intermittency as the share of wind power increases, and reduced flexibility on the supply side as the share of conventional power generation is reduced. The challenge for the electricity grid and for transmission system operators is amplified by the relatively high levels of intermittent wind power that can be expected as a result of renewable policies, especially if trade in renewable certificates and increased interconnector capacity is made available. Such a development would also affect existing thermal power plants, with a likely increase in generation cycling and the numbers of annual start-ups and stops. Therefore, high levels of wind power (and other intermittent production) will also require a higher degree of flexibility on the demand side, e.g., from electric boilers, both at the end-user side and in district heating, and from electric vehicles and other means for temporarily storing electricity.

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14 The impact of the EU ETS on electricity generation across Europe

Currently, there exists a significant, albeit unexploited, potential to reduce significantly the levels of CO_2 emissions from the European electricity supply in a very short-term perspective. The "problem" is that EU emission allowance (EUA) prices are currently too low to realise that reduction potential. If EUA prices were to increase substantially to >20 €/t CO_2, the dispatch in the existing European electricity supply would be significantly affected. Efficient gas-fired power plants would increase their running times and coal-fired power plants would reduce their outputs accordingly. The model calculations presented in this chapter reveal that CO_2 emissions from electricity generation are reduced by approximately 20% if EUA prices approach 40 €/t CO_2. This corresponds to approximately a 10% reduction in the whole EU ETS, since emissions from power supply plants amount to roughly half of the total emissions within the EU Emission Trading System (EU ETS). However, considering the existing oversupply of EUAs, these price developments appear to be unlikely in the foreseeable future. Furthermore, the short-term reduction potential identified here may be jeopardised in a longer time perspective by the currently low utilisation of existing efficient gas-fired power plants, which may lead to permanent closures.

Impact of increasing EUA price on the short-term electricity supply

Since the beginning of Year 2013, the EUA price has remained below 7 €/CO_2. This is due to a persistent oversupply of emission allowances induced by a lower than anticipated demand, as caused by the global recession and a substantial increase in the penetration of renewable energy, which, in turn, has been spurred by different support schemes. Consequently, the current gas-to-coal price ratio has increased the competitiveness of coal-fired power plants over gas-fired power plants that have significantly lower specific CO_2 emissions (see also the "Setting the scene" section of this book). From the point-of-view of climate, this is, of course, an undesirable development. If EUA prices increase, for any reason, the competitive relationship between coal-fired and gas-fired power production will change. In fact, not only the current European market prices for coal, gas, and carbon, but also the substantial increases in renewables have generated a growing underutilisation of gaspower capacity across Europe. If EUA prices increase, the available capacity will increase its running time, thereby replacing some of the coal-fired power production. As EUA prices increase, coal-fired electricity generation rapidly becomes more expensive. In addition, gas-fired power becomes more expensive, although to a substantially lesser extent than coal-fired power. At the same time, wholesale prices for electricity increase.

A series of EPOD model[1] runs have been performed to analyse the impact of EUA price increases on the existing European electricity supply (specifically, model Year 2015). If the EUA price reaches 40 €/CO_2 gas-fired power production increases by around 300 TWh. This represents about one-third of the current gas-fired power production or almost 10% of total European power production (see Figure 14.1). According to the Chalmers Power Plant Database, the capacity of natural gas-fired power is approximately 220 GW in the EU-27 plus Norway and Switzerland by the end of Year 2013 (since we use model Year 2015, additional investments are possible but limited). Thus, the calculated total production level from gas power of around 1100 TWh at 40 €/CO_2corresponds to an average annual running time of roughly 5000 hours. Of course, a large variety of gas-fired units is included in that capacity, ranging from dedicated peak-load gas turbines to base-load combined cycle gas turbine (CCGT) power plants with relatively low running costs. Furthermore, the running times of existing biomass-fired power plants increase as the EUA price increase. However, the contribution of that increase in terms of generated electricity is marginal.

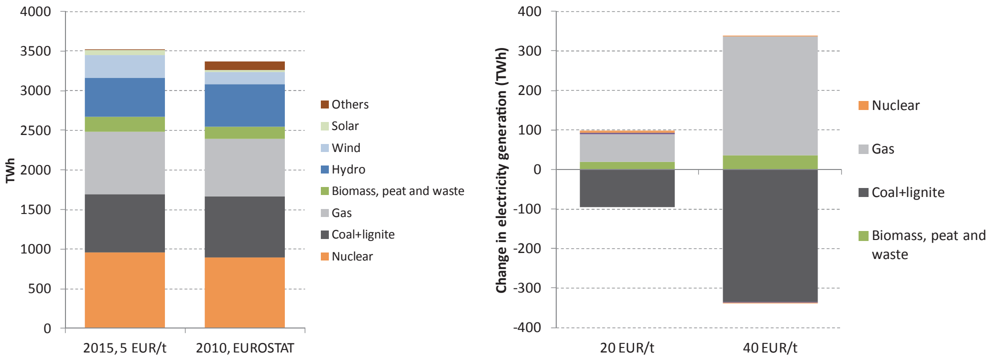

Figure 14.1. *Left panel: Electricity production levels in the EU-27 plus Norway and Switzerland, as estimated by the EPOD model for model Year 2015 (and, for comparison, the Eurostat statistics for 2010). Right panel: changes in electricity production as EUA price changes from 5 €/CO_2 to 20 €/CO_2 and 40 €/CO_2 , respectively (i.e. as compared with the situation in the left panel where the EUA price is assumed to be 5 €/CO_2).*

Impact of increasing EUA price on CO_2 emissions from electricity production

With a switch from coal to gas for power production, induced by an increase in the EUA price, CO_2 emissions decrease accordingly. If the EUA price rises from the current typical level of 5 €/tCO_2 to a level of 40 €/tCO_2, CO_2 emissions from the European power production will, according to our model results, decrease by approximately 20% (see

[1]The EPOD model is further described in the Method section of this book

Figure 14.2). Under current conditions, CO_2 emissions from the European (EU-27 plus Norway and Switzerland) electricity production amount to approximately 1000 Mt in model Year 2015[2].

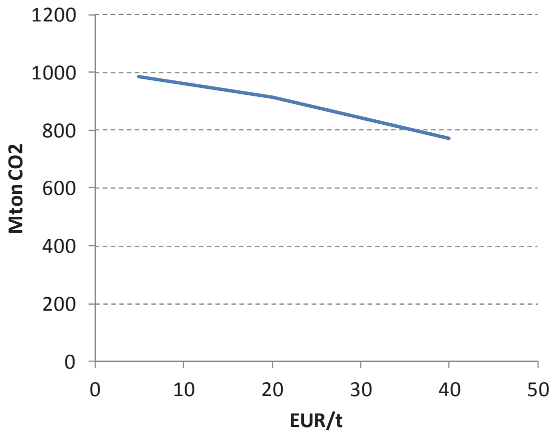

Figure 14.2. *Levels of CO_2 emissions from European electricity production (EU-27 plus Norway and Switzerland) as a function of EUA price based on EPOD model runs for model Year 2015.*

In Figure 14.3, we present the corresponding reduction in CO_2 distributed across the different European countries. The largest reductions in emissions occur in Germany, followed by Spain, Poland, Romania, Greece, the Czech Republic, and the UK. The reason that the UK does not take a larger share of the overall reduction is that by 2015, a substantial part of the existing coal-fired power plant fleet has been retired due to the LCPD (Large Combustion Plant Directive). This is also briefly mentioned in the *"Setting the scene"* section of this book.

[2] EURELECTRIC estimates CO_2 emissions from electricity production in 2010 in EU-27 plus Norway and Switzerland to be around 1100 Mt (statistics available at http://www.eurelectric.org/factsdb/)

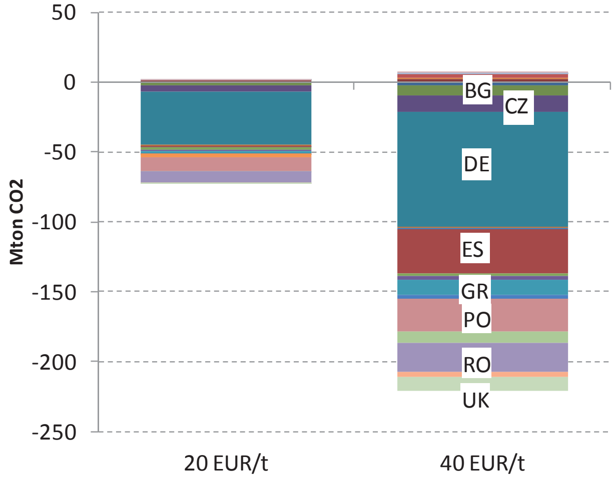

Figure 14.3. *Reductions in CO_2 emissions attributed to specific EU Member States for a EUA price of 20 €/tCO_2 and 40 €/tCO_2, respectively, as compared with a price level of 5 €/tCO_2.*

Impact of increasing EUA price on European marginal costs of electricity generation

If EUA prices rise in the short term, the marginal costs (MCs) of electricity generation, and thus wholesale electricity prices, rise accordingly. The extent to which the MCs of electricity will rise depend upon the technology on the margin, i.e., the "price setter". For a typical gas-fired power plant, the cost increase for a given increase in EUA price is lower than that for a typical coal-fired power plant. In Figure 14.4, the increase in MC is shown for each price area included in the EPOD model (53 price areas defining the EU-27 plus Norway and Switzerland - in the figure, single price areas are grouped according to geography). We conclude that MCs are lowest in the Nordic countries and possibly in some price areas in France, whereas certain Eastern and Southern European countries and the UK (with the exception of Scotland) have the highest MCs. High MCs in Eastern Europe are due to the fact that coal-fired power dominates the existing supply and that the possibility for a coal-to-gas switch is very limited in the existing system. However, in Southern Europe and the South and Mid UK, gas-fired power is already largely determining the MC, which implies that the cost increase is relatively limited and that it is already at a relatively high level in the staring phase (cf. blue upper line representing South and Mid UK in Figure 14.4).

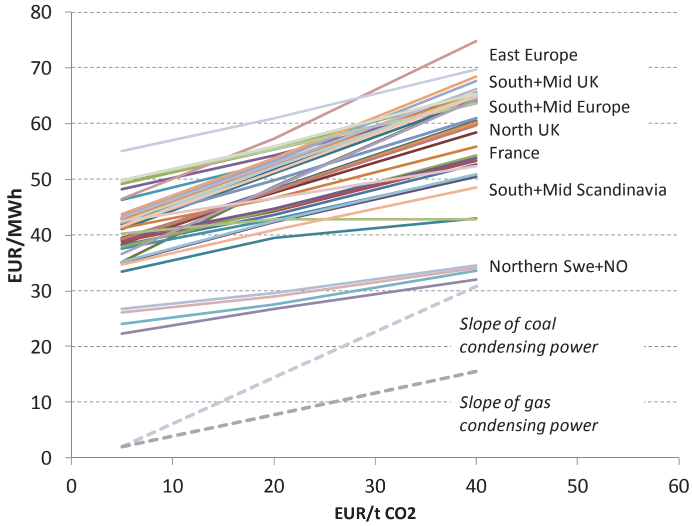

Figure 14.4. *Marginal cost of electricity as a function of increasing EUA price in all 53 European (EU-27 plus Norway and Switzerland) EPOD regions for model Year 2015. In order to improve readability the single regions are coarsely grouped into geographical entities. The slopes of the increase in running cost of a typical coal-fired condenser power plant (electric efficiency of 40%) and a typical gas-fired condenser power plant (electric efficiency of 52%) are shown for comparison purposes.*

In Figure 14.5, the same information as in Figure 14.4 is shown except that it is collated for groups of European power markets. Once again, the Nordic countries are at the lower end of the scale, while the UK and Southern Europe are at the higher end of the scale. If EUA prices approach 40 €/tCO_2, the MC of electricity becomes relatively high also in Eastern Europe (CEE). For comparison, the figure contains information on the actual reported prices in these markets, shown as typical price intervals between Year 2010 and the beginning of 2013 (extremely high and extremely low prices have been omitted). It is evident that variability is greatest in the Nordic wholesale market, due to the large annual variations in hydropower. Nevertheless, in general, wholesale prices in the Nordic region are the lowest in Europe. In the other markets, prices are generally higher with lower annual variations being affected, for example, by annual variations in fossil fuel prices. That the reported prices in Italy deviate substantially from the ones estimated in the model runs may reflect the fuel price assumption. In our model analyses, we generally assume similar fuel prices across all the European countries. In reality, gas markets, for instance, tend to be regional within Europe, entailing significant differences in wholesale gas prices.

For example, in Italy, wholesale gas prices were significantly higher, typically around 5-10 €/MWh, than in the UK, during the period 2011–2012. In both countries, gas-fired power is important as a price setter for the wholesale electricity market. We have not taken such regional differences in the fuel markets into account, which partially explains the differences between the regional calculations of MCs and the reported regional wholesale electricity prices.[3]

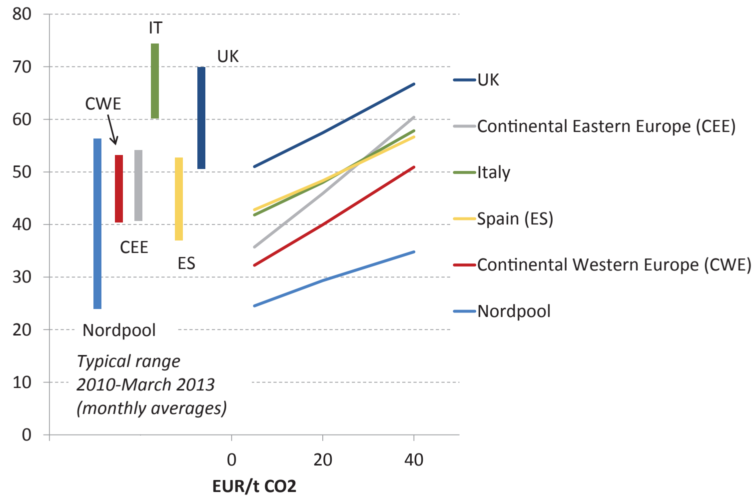

Figure 14.5. *Calculated marginal costs of electricity, as a function of increasing EUA price, in selected European electricity markets (lines). Bars represent a typical interval (excluding extreme values) of wholesale electricity prices in the same European markets observed between Year 2010 and March 2013. Source: EC Market observatory for Energy (2013).*

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[3] The model calculates the marginal cost of electricity rather than the wholesale electricity price. The MC of electricity is, nevertheless, a decisive component of the wholesale electricity price. Since the model is not primarily intended for actual market simulation, which would include risk aversion, uncertainties, perceptions etc., we choose to report our results in terms of marginal costs rather than prices.

15 Limits for CO_2 emission abatement in the industry sector

Currently, the power and industrial sectors account for almost half of all GHG emissions in the EU. This chapter provides a technology-based perspective on the feasibility of deep cuts in CO_2 emissions up to Year 2050 from large stationary sources of CO_2 in the EU, including sites of power generation, petroleum refining, iron and steel production, and cement production. The focus is on exploring the extent of CO_2 emission reduction that can be achieved using presently available abatement technologies. By deliberately excluding CCS from this analysis, we provide an indirect measure of the requirements for new low-carbon technologies and production processes. The results confirm that the EU short-term goal in relation to reducing GHG emissions, i.e., a 21% reduction by Year 2020, as compared to the levels in Year 2005 (EU ETS), is achievable with the abatement measures that are already available. However, despite the confidence that exists regarding the potential for, and implementation of, available abatement strategies within current production processes, our results indicate that the power and industrial sectors will fail to reach the more stringent reduction targets in both the medium term (Year 2030) and long term (Year 2050). This underlines the importance of boosting the development of novel low-carbon technologies and production processes, especially in the industrial sector. This chapter is based on the work presented in Rootzén and Johnsson (2013a).

Exploring the limits of CO_2 emission abatement

In February 2011, the European Council reconfirmed the goal of reducing greenhouse gas (GHG) emissions in the EU by at least 80% by Year 2050, as compared to the levels in Year 1990. This chapter presents an assessment on the prospects for future CO_2 emission reductions in three major CO_2-emitting activities of the European (EU-27 countries and Norway) industry, namely, petroleum refining, iron and steel production, and cement manufacturing. For comparison, the power sector is also included, yet more simplified than in the several chapters dedicated to the different parts on the electricity sector.

Many of the power plants and industries that are currently in operation were commissioned in the period 1960–1980. Thus, a large fraction of the existing capital stock will need to undergo major refurbishments or be replaced within the coming decades. Critical questions as to when, how fast, and to what extent new low-carbon technologies can penetrate these sectors need to be addressed. With a time horizon of less than four decades, significant technological progress is possible and indeed likely. However, there are considerable uncertainties associated with the assumptions that have been made in relation to the timing of the introduction and the extent to which new low-carbon technologies can penetrate the different sectors. In this study, rather than addressing the prospects of new low-carbon technologies, we instead focus on exploring the limits of CO_2 abatement within current production processes. This means that technologies that are not yet commercially available, such as CCS, are not included as abatement alternatives in any of the sectors. In addition, radically new iron, steel, and cement production processes are not considered. However, by comparing the emission trajectories derived from different scenarios (see below) with indicative emission caps (trajectories) for the period 2010–2050, we provide indirect measures of the requirements for new low-carbon technologies and industrial production processes to meet EU targets.

Annual CO_2 emissions for the period 2010–2050 were derived for each activity by exploring factors relevant to future CO_2 emissions in each sector. These factors, which included activity level, age structure, structure of production, market characteristics and trends, fuel mix, and deployment of available abatement options, formed the basis for the development of various future scenarios.

In total, six scenarios were analysed. For the future development of the power sector, three scenarios are applied, each of which describes a different future with respect to technology and fuel mixes: 1) the Low-Carbon scenario (LC scenario) depicts a situation in which no additional fossil-fuelled capacity is allowed beyond Year 2010; 2) the Fossil Scenario (FO Scenario), which assumes that all currently planned and proposed fossil-fuelled power plant projects (as listed in the Chalmers Power Plant database) will be deployed in the period 2010–2020 (adding approximately 150 GW of fossil capacity up to Year 2020); and 3) the Natural Gas scenario (NG Scenario), which implies that all fossil capacity additions (150 GW, as in the FO Scenario) are assumed to be in the form of natural gas CCGT plants. In all three scenarios, electricity demand is assumed to increase linearly to 31% by Year 2050 relative to demand in Year 2010. The other industrial sectors have one scenario each that describes the future development of the production mix for each sector. The production levels of steel and cement are assumed to increase moderately up to Year 2020 and thereafter remain constant, while the total output from EU refineries is assumed to decrease by almost 60% up to Year 2050, as compared to the total output in 2010. Scenario inputs have been chosen to reflect a development in which ambitious measures are taken to exploit the abatement strategies currently available in each sector. For a more complete description of the applied scenarios and methods, see Rootzén and Johnsson (2013a).

Scenario results

The potentials for emission reductions were estimated by comparing the cumulative annual emissions for each of the above mentioned scenarios[1] with the corresponding emissions in the baseline case. In the baseline case, the technology and fuel mix are kept constant in all sectors throughout the studied period. Thus, while the levels of activity increase in all the sectors (with the exception of the petroleum refining sector), the CO_2 emission intensities are frozen at the levels of Year 2010.

[1] These scenarios should not be confused with the four main scenarios described in Chapter 10.

Figure 15.1 shows the estimated reduction potentials for the power and industrial sectors for the period 2010–2050. In the short-term, overall CO_2 emissions decrease by 13%–34%, i.e., from 1715 $MtCO_2$/yr in 2010 to 1200-1570 $MtCO_2$/yr in 2020. These results suggest that, provided that the RES capacity expansion projected in the EU Member States' National Renewable Energy Action Plans is realised but not all the planned coal and lignite plants come online, the short-term emission reduction goal (-21% by Year 2020, as compared with Year 2005) should be achievable.

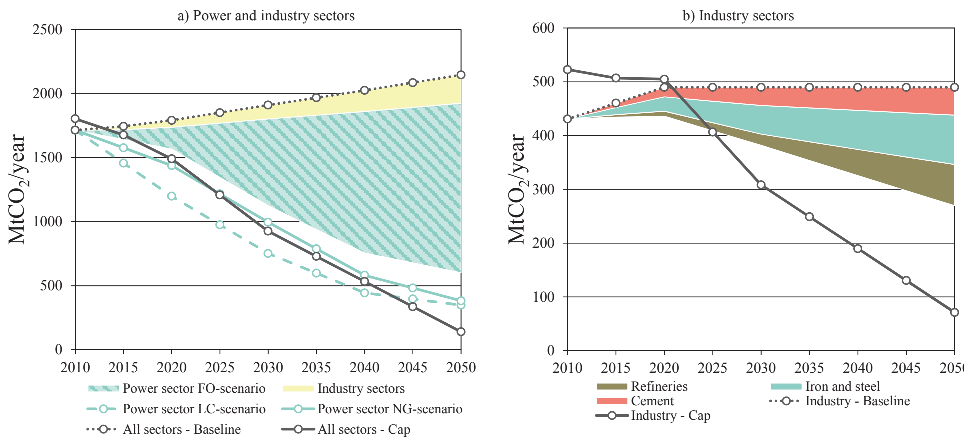

Figure 15.1. *Emission reduction potentials relative to the baseline case in which technology and fuel mixes are frozen at the levels in Year 2010. a) Aggregate emission reductions for the power and industrial sectors relative to the baseline case. b) Emission reductions achieved in each of the industrial sectors relative to the baseline case.*

The total abatement potential in Year 2050 for the sectors investigated is estimated to be in the range of 1500–1800 $MtCO_2$. This corresponds to a 65%–80% reduction relative to the levels in Year 2010. As illustrated in Figure 15.1a, the feasibility of deep reductions in emissions is ultimately dependent upon the development of the EU power sector. The upper estimate of the reduction potential, i.e., 80% decrease (compared with the Year 2010 levels) by Year 2050, assumes that no additional unabated fossil fuel capacity is allowed in the power sector beyond 2010 (the LC scenario). The lower estimate of the reduction potential, i.e., 65% below the Year 2010 levels by Year 2050, assumes that all fossil-fuelled power plant projects currently in various stages of planning will be commissioned in the period 2010–2020 (the FO scenario). Thus, the results indicate that if investments in new unabated coal and lignite capacities are avoided there is a reasonable chance of accomplishing the goal for Year 2050. This, in turn, implies that low- (and zero-) carbon power generation capacity would need to be scaled up considerably. Our estimates suggest that in addition to the assumed capacity expansion in 2010–2020 and the RES and nuclear capacity replacements (see the descriptions of the LC scenario and NG scenario), to balance demand in the medium and long terms, investments in new power capacity will be needed to generate 600–1000 TWh/yr in 2030 and at least 2000 TWh/yr in 2050. It should be noted that these estimates are intended to provide a measure of the magnitude of the required expansion of capacity for low-carbon power generation technologies and depend heavily on the assumptions that the total installed capacity of nuclear power in the EU remains constant throughout the studied period and that there will be a linear growth in electricity demand from 3250 TWh in 2010 to 4250 TWh in 2050.

Figure 15.1b summarises the emission reduction potentials for each of the industrial sectors. Despite the extensive measures that are assumed to be implemented, the results indicate that the industrial sectors will fail to comply with the long-term reduction targets, unless CCS is applied or there is a major breakthrough in other new low-carbon process technologies materialises between now and 2050.

In Figure 15.1 the total CO_2 emissions from industry are estimated to be 270 $MtCO_2$/yr in 2050, i.e., 40% below the Year 2010 levels and 45% below the baseline level of emissions. Provided that the power sector is able to comply with the target emissions trajectory, this implies that aggregate emissions from petroleum refining and iron, steel, and cement manufacturing would account for more than 75% of the total emissions from the assessed sectors in Year 2050.

Key priorities and challenges

Transformation of the power and industrial sectors so as to reduce radically the levels of CO_2 emissions represents a double-edged challenge. This transition involves the phasing-out of current carbon-intensive technologies, together with the phasing-in of new zero- or low-carbon technologies to fill the capacity gap. While a sufficiently high price for CO_2 is a prerequisite for these two events to occur, the development and large-scale diffusion of new low- or zero-carbon technologies require additional policy measures.

Any attempt to suggest priorities with respect to the measures that would enable significant reductions in emissions from the assessed sectors is doomed to be subjective and incomplete. Nevertheless, based on the analysis performed within the present study, we have identified some key priorities, and associated challenges, as presented in Table 15.1.

Table 15.1. Summary of key priorities and barriers to the implementation of measures to reduce emission levels in the assessed sectors

	Priority	Key challenges
Power sector	Reduce demand/limit demand growth.	Growth in demand in key end-use sectors driven by the shift from fossil fuels to electricity.
	Avoid any new investments in coal- and lignite-based capacities without CCS.	Several EU Member States still have untapped fossil fuel reserves.
	Develop and deploy renewable capacities	Challenges associated with high penetration of intermittent renewables still need to be resolved (i.e., transmission and storage issues). In addition, with high diffusion rates, public acceptance may become a more serious problem.
	Develop other technologies with low- or zero-carbon emissions (i.e., nuclear power and power plants equipped with CCS)	Nuclear power is the energy source that arouses the greatest controversy. Many challenges are still largely unresolved (e.g., radioactive waste disposal, nuclear proliferation, guaranteeing reactor safety). Large-scale CO_2 capture is still not commercially proven. Public acceptance may be a problem.
Petroleum refineries	Reduced demand in end-use sectors	Dependent upon the development of alternative fuels/power-trains in the transport sector. May be difficult to develop reliable substitutes in certain end-use sectors, e.g., fuels in the aviation industry and non-fuels in the petro-chemical industry.

	Fuel shift	Large-scale shifting to biomass fuels seems unlikely, and the effects of a shift to natural gas are likely to be marginal.
	Develop CCS	CCS is still in its infancy (for a review, see Johnsson et al., 2012).
Iron and steel	Improved thermal and electric efficiencies	Minimum thermal energy requirements are theoretically and practically limited (Fruehan et al., 2000).
	Fuel shift	Coke functions as both a fuel and as a reducing agent, and provides the flow characteristics required in the blast furnace in the conventional process. Thus, substitutes must provide the same 'services'.
	Structural change	Certain market segments require high-quality primary steel. Quality standards may limit the total share of secondary steel.
	New steel-making processes (including CCS)	Alternative (low-CO_2) steel-making processes are still in the early phases of development (ULCOS, 2012).
Cement	Improved thermal and electric efficiencies	Minimum thermal energy requirements are theoretically and practically limited.
	Alternative fuel use	The maximum share of biomass that can be used in a conventional cement kiln is limited by practical considerations.

	Clinker substitution	Quality requirements may limit the use of clinker substitutes in the finished cement.
	New cement-making processes (including CCS)	Alternative (low-CO_2) cement manufacturing processes are still in the early phases of development (Croezen and Korteland, 2010).

What if CCS is an option?

Above chapter highlights how EU carbon-intensive industries will experience difficulties in complying with long-term CO_2 emission targets if restricted to proven best-available technologies. Nonetheless, CCS is recognised as a promising option for CO_2 mitigation from centralised emission sources. We have therefore, in a complementary study (Rootzén and Johnsson, 2013b), explored the implications of large-scale implementation of CCS in EU industry. Given the technology mix of the existing capital stock in the EU refining, steel, and cement industries, we assess how fast and to what extent CCS can be implemented and at what cost, in terms of energy use.

The potential role of CO_2 capture is explored through a scenario-based analysis. Three scenarios, one for each industrial branch, which describe the development of key characteristics and trends that govern future energy use and CO_2 emissions, have been developed. For each scenario, three to five alternative cases for the deployment of CO_2 capture are analysed, which cover:

- The possibility to retrofit plants commissioned before 2030 with CO_2 capture: and
- Capture technologies (post-combustion and/or oxyfuel combustion).

For all industries, CO_2 capture is assumed to be available on a commercial scale from Year 2030. While earlier introduction seems unlikely at the current rate of development, delayed introduction would have deleterious effects on the prospects for CCS to contribute to reducing substantially CO_2 emissions up to Year 2050.

The results of the current analyses show that:

- Combining the most ambitious CCS deployment trajectories in each of the industries investigated would result in an 80% reduction in CO_2 emissions, from 440 $MtCO_2$/year in 2010 to 80 $MtCO_2$/year in 2050.

• Depending on which capture technology that is assumed to dominate, large-scale introduction of CO_2 capture would result in the total energy use in Year 2050 being at the same level (thermal energy) or at a significantly higher level (electricity) than the level in Year 2010, despite reduced industrial activity.

• When retrofit is not included as an option, the contribution of CCS to total emissions reduction is limited. This underlines the importance of overcoming barriers to retrofit CO_2 capture to the assessed industrial processes.

Figure 15.2 presents the projected CO_2 emissions trajectories, together with data on the aggregated thermal and electrical energy use for EU cement plants over the period studied, for the case without introduction of CCS (C0) and for the case with the most ambitious deployment of CCS (C4).

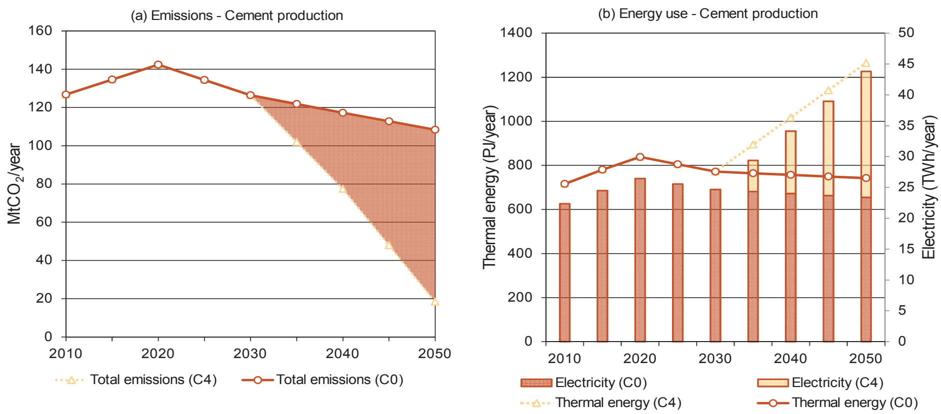

Figure 15.2. *Estimated CO_2 emissions and energy use for the EU cement industry in the period 2010–2050, as obtained from this work. Case C0 assumes ambitious implementation of available mitigation measures but excludes CCS as an abatement option. In case C4, from Year 2030 onwards, cement kilns fitted out for full oxycombustion are assumed to be the standard for new capacity and all remaining cement plants commissioned before this year are retrofitted with post-combustion capture. (a) The estimated annual CO_2 emissions from EU cement manufacturing in the period 2010 – 2050, with (dashed line) or without (solid line) the introduction of CCS. In both cases, total emissions include both fuel-related and process-related emissions. (b) Estimated development of thermal (solid/dashed lines) and electrical (bars) energy use with (light-orange) or without (orange) the introduction of CCS.emissions include both fuel-related and process-related emissions. (b) Gives the estimated development of thermal (solid/dashed lines) and electrical (bars) energy use with (light orange) or without (orange) introduction of CCS.*

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Large-scale integration of renewable electricity

In this section, we consider the issues that are crucial to the implementation and acceptance of an ambitious and successful large-scale integration of renewable electricity. The research presented here focuses on wind and solar power, and deals with various topics, including the interplay between wind power and other electricity generation technologies, such as thermal power and hydropower. We also elaborate on the Europe-wide consequences of the marginal costs of electricity generation with significant penetration of variable renewable electricity, as well as on efficient strategies to allocate wind power across the EU. This section concludes with a chapter on capacity markets, an issue that is widely discussed across the EU and represents a means to facilitate reserve capacity in a system that has both a high share of renewables and variable production.

16 Regional differences in future renewable electricity

The EU renewable energy directive (RED) sets binding targets for each Member State, which collectively amount to 20% renewables in the gross final consumption by 2020. According to the Member States' action plans and projections, this implies approximately 35% renewables within the electricity generation sector. Variable renewable electricity generation, i.e., primarily wind and solar power, would supply approximately 15% of gross electricity consumption according to the same plans. Such a significant expansion of (variable) renewable electricity will significantly affect several regions across Europe. Regions with superior prospects for future wind investments will have renewable electricity shares that far exceed the corresponding national target. Consequently, low short-run marginal costs of electricity generation will yield low wholesale electricity prices in such regions, given that they define separate price areas on the European electricity markets. According to model analyses, for Year 2025 such regions include Scandinavia, northern Germany, and northern UK.

Assumptions

In the analysis, we assume that variable electricity, i.e., wind and solar power, will supply around 20% of the total demand for electricity in EU-27, Norway, and Switzerland by Year 2025. Thus, we assume continued expansion of variable renewable electricity beyond the projection of 15% by Year 2020 made by the Member States' action plans, which were submitted in 2010. Total electricity demand in the entire region is assumed to increase only moderately, i.e., by about 10% by Year 2025 compared to the demand in Year 2010, in the investigated scenario[1].Furthermore, carbon prices are estimated to reach 15–20 €/tCO_2 around Year 2025. The maximum interconnector capacities are in this study limited to existing capacity similar to actual Net Transfer Capacities (NTC values). Given this, the transmitted or traded electricity flows through a given interconnector in each time period are, however, model results and depend on the actual load situation in that period.

Regional distribution of variable electricity generation

Figure 16.1 shows the penetration levels of wind and solar power for each region, given as the annual generation level relative to the annual gross demand for electricity, as obtained from the EPOD modelling[2]. Wind power generation far exceeds solar power generation

[1] The model analysis in this chapter is based on Regional Policy assumptions (see Chapter 10).

[2] The EPOD model is described in the Method section of this book.

in the investigated scenario. As indicated in the figure, the penetration levels of wind and solar power are particularly high in Scotland, northern Germany, and Denmark. For these regions, wind power has a significant impact on marginal costs during high-wind events. However, the absolute production levels from wind and solar power in these regions are not necessarily high. It is the share relative to regional demand that is high in these regions. In the case of northern Germany, the penetration level is high owing to good wind sites and a high national target for renewable electricity (in absolute values). Thus, a very high level of renewable electricity generation is allocated to a region that is moderately populated and that has a moderate demand for electricity. In northern Sweden, the penetration of wind power is relatively high, as a moderate level of wind power is allocated to a region that is very sparsely populated and, as a consequence, characterised by a low demand for electricity.

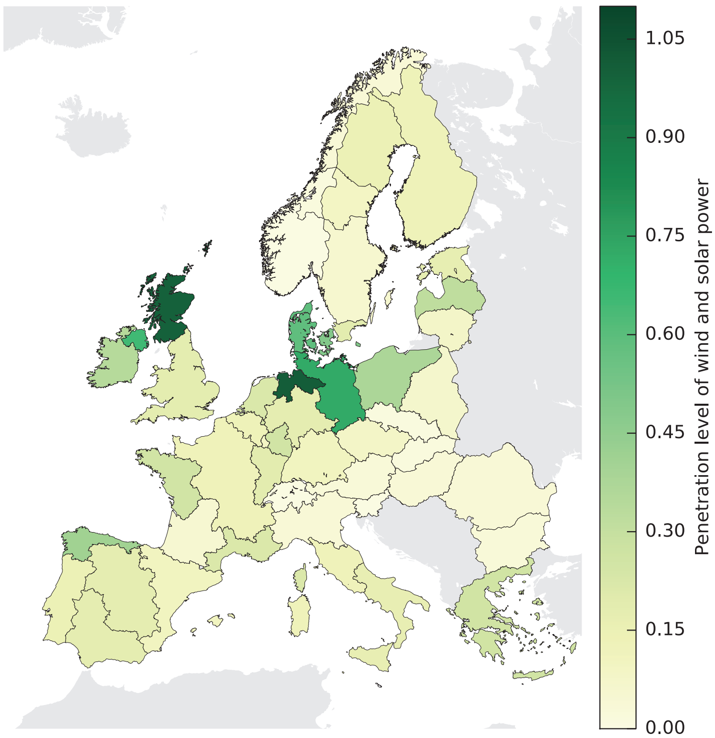

Figure 16.1. *Penetration levels of wind and solar power in the EU, Norway and Switzerland for Year 2025, i.e., levels of wind and solar generation relative to the levels of demand for electricity, as obtained from the modelling. Source: Göransson et. al., 2014.*

Results for marginal electricity generation costs

Figure 16.2 shows the annual average marginal cost (MC) of generating electricity, as provided by EPOD modelling for the Year 2025 and based on the Regional Policy scenario. Since variable renewable electricity generation is characterised by very low running costs and fluctuating levels of production, this will propagate to the system level once the share of this type of electricity generation becomes sufficiently high. Since such installations are dependent upon electricity prices that significantly exceed their low running costs, so as to recuperate capital costs, problems may arise if the share of variable electricity production becomes high in a given market price area.

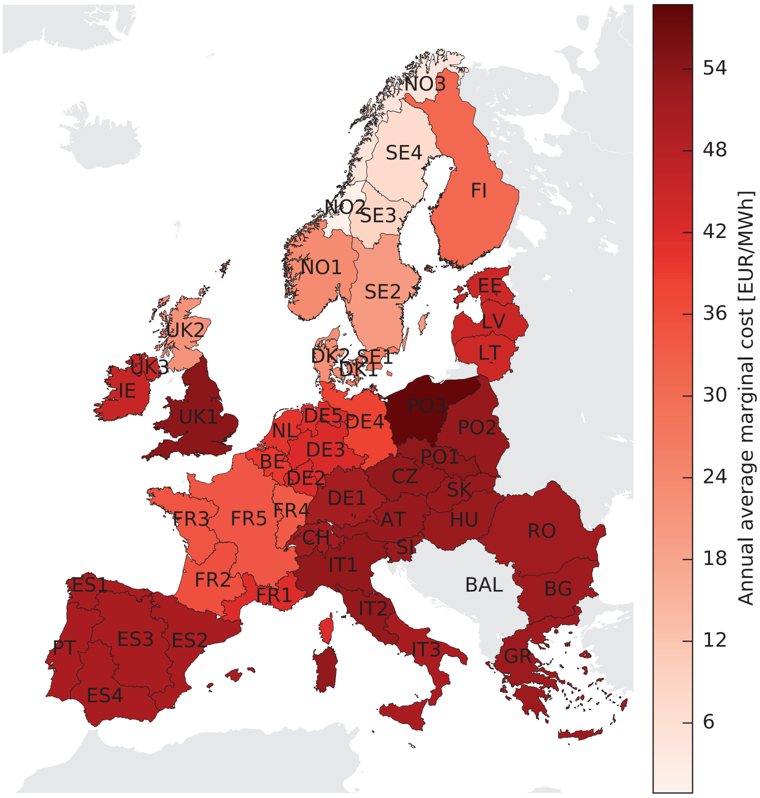

Figure 16.2. Regional distributions in the EU, Norway and Switzerland of marginal costs for electricity generation, as obtained from the EPOD modelling. Source: Göransson et. al., 2014.

Based on the model results reported here, the main trends are that north-eastern Europe, Italy, and the Iberian Peninsula have the highest annual average MCs for electricity generation, whereas the Nordic countries have much lower MCs. The low MCs for electricity, compared with the present situation, are explained by the scenario assumptions (cf. Regional Policy scenario in Chapter 10), i.e., large outputs of renewable electricity are assimilated, through subsidies, into the generation system at the same time as the growth in demand for electricity (especially in northern and western Europe) is low. The difference in MCs between the northern regions and southern regions of the Nordic countries is likely to be somewhat overestimated in this work given the underestimation in the EPOD model of the maximum flow of power between regions SE3 and SE2[3]. This also contributes to the particularly low MCs for electricity in northern Scandinavia. Furthermore, the model does not consider uncertainties and risk aversion, which may introduce a bias in relation to the seasonal production pattern of hydropower, entailing an overestimation of hydropower production during high-price periods, and thereby limiting extent of spikes in MC.

To conclude, the model analysis clearly identifies the regions bordering the Baltic and North Sea as low-cost electricity generation areas based on national targets for renewables, suitable wind conditions, and abundant hydro resources. This, in turn, may spur a trans-European electricity transfer from the northern, low-cost areas to the southern European areas where MCs for electricity generation are likely to be significantly higher. To exploit fully this situation, interconnector capacities and domestic transmission capacities, e.g., in Germany, must be expanded. This facet has not been included in the present analysis (such considerations are part of the succeeding chapter, which deals with the role of Nordic hydropower).

[3] The model regions for Sweden do not fully correspond to the actual price areas in Sweden. We have also used a reversed denotation (south is SE1 in our model).

Congestion in the European transmission network

Large-scale integration of variable renewable electricity generation across Europe is likely to significantly impact transmission of electricity and bottlenecks in the European electricity-transmission grid. In the research presented in this book, model methods have continuously been developed and refined in order to also handle issues related to the electricity grids. The modelling results show that congestion patterns change significantly as penetration of variable production increases. In Figure 16.3 two types of trans-European congestions, following a large-scale integration of variable renewable electricity in Year 2020, are presented: a) peak load situation and, b) high wind situation.

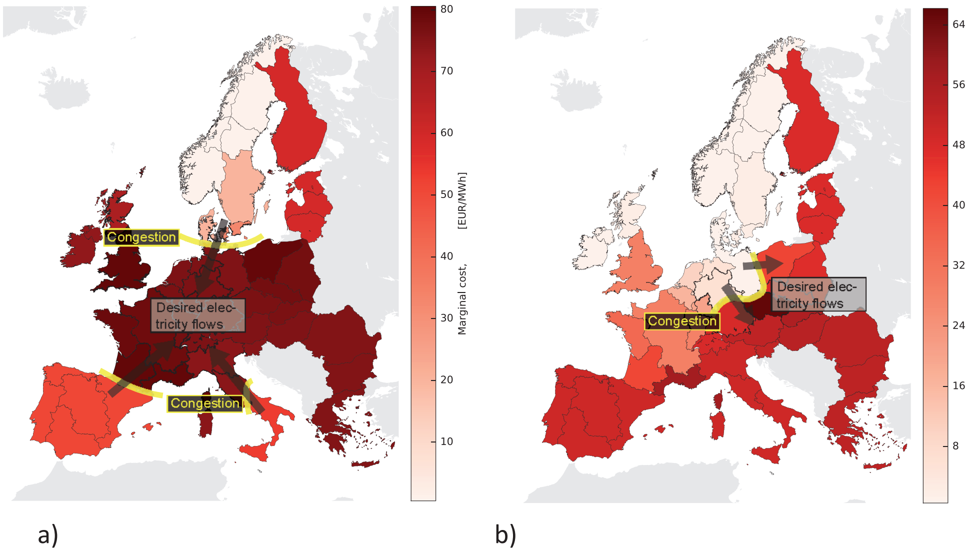

Figure 16.3. *Marginal costs for electricity generation in the 50 European regions modelled in the EPOD model for two different load and supply situations for Year 2020. Congestion is substantially different in the two cases. The degree of congestion is, in turn, defined as the difference in marginal costs between regions. Panel (a) shows a peak load time-step in which continental Europe has high marginal costs and congestion limits the distribution of solar power from southern Europe and (mainly) hydropower from the Nordic countries. Panel (b) shows a high-wind situation in which wind power from northern Europe is unable to reach the southern regions via the congested transmission system.*

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17 The impact of wind power on the operation of thermal power plants

Given the increased penetration of wind power and other variable renewable electricity generation, the role of conventional thermal power is being reassessed. The running time for thermal power plants will be reduced as existing wind power plants position themselves at the low-end of the marginal costs curve for electricity supply. Increased part-load operation and/or increases in the number of starts and stops of thermal power plants will entail increased costs and more emissions. Nevertheless, to ensure stable electricity supply, back-up capacity, in the form of thermal power plants with high capacities to deliver power when it is needed the most, will be needed for the foreseeable future. The challenge lies in developing efficient ways to maintain this capacity as the share of renewable electricity increases continuously.

The basics

A reduction in load or an increase in variable renewable electricity (vRES) generation in a vRES-thermal power system that uses no active strategy for variation management (i.e., storage or demand-side management) can be managed by:

- Part-load operation of thermal units:
- Stopping thermal units; or
- Curtailing renewable power (i.e., not exploiting fully the potential renewable electricity generation to hand).

The choice of variation management strategy depends on the properties of the thermal units that are available for management (e.g., in order to choose to stop a unit it obviously has to be running) and the duration of the variation. In a power system in which the total system cost (i.e., running costs, start-up costs, part-load costs and possibly, the priced cost of emissions) is minimised, the variation management strategy associated with the lowest cost is the obvious choice. If, for example, the output of wind power and some large base-load unit exceeds the demand for 1 hour, curtailment of wind power (or possibly some curtailment in combination with part load of the thermal unit) might be the solution that represents the lowest total system cost. If the same situation persists for 12 hours, stopping the thermal unit might be preferable from a cost-minimising perspective. To facilitate variation management decisions with respect to the dispatch of units, knowledge of the start-up and part-load properties of the thermal units is necessary.

Cycling properties of thermal power plants

Cycling of a power plant is defined as any operation that deviates from the normal or rated output. This includes part-load operation, e.g., for load-following purposes, and stops and starts. Cycling properties, which vary significantly between different power plant technologies and sizes, have an immediate impact on the scheduling of the units. Three cycling properties are important to consider in terms of scheduling: the minimum load level; the start-up time; and the start-up cost. The start-up time is measured either as the time it takes to warm up a unit before it reaches a state in which electricity can be delivered to the grid (time for synchronisation) or as the time that elapses before it delivers electricity at the rated power (time to full production). In both cases, the start-up time ultimately depends on the capacity of the unit, the power plant technology, and the amount of time that the unit has been idle. The latter period defines cold, warm, and hot starts. For a coal-fired power plant, the typical start times are 7–8 hours (cold), 4 hours (warm), and 1.5–2.0 hours (hot) (Cochran et al., 2013). Small gas turbines have relatively short start-up times, of about 15 minutes, while large steam turbines have long start-up times, up to several hours (up to 3 days for supercritical coal). If a large unit has lain idle for a few hours, the materials may still be warm and the start-up time can be reduced. In Table 17.1, typical values that govern the cycling properties, as used in the modelling, are presented.

Table 17.1. Properties for assigning aggregate specific start-up and part-load costs for fuel categories in the EPOD model.

	Start-up time [h]	Min load level [%]	Min efficiency [% of max efficiency]
Coal	6	35	50
Gas	0/6	20	50
Oil	6	20	50
Lignite	6	50	70
Peat	6	50	70
Biomass	6	50	70
Waste	6	50	70
Nuclear	24	80	80

A low minimum load level is of great importance for any load-following thermal unit, since it allows for operation over a wide range of load situations and reduces the need for cycling. Size matters when it comes to cycling properties, as small units have a low minimum load level in absolute terms. It may be possible to find a combination of small units that suits the load situation at hand and that involves only the starting/stopping of a few of the units. In contrast, for a large unit, the choice is between shutting down (and subsequently restarting) the whole capacity or delivering power at a marginal cost that is less than the running cost. Start-up costs are typically in the range of 10–30 €/MW for gas-fired technologies and 30–70 €/MW for coal-fired technologies (Kumar et al., 2012 and own estimates). Cold starts are at the upper end and hot starts are at the lower end of the cost interval.

Increased cycling of a power plant entails increased operational costs. In the case of a start-up this is due to the fact that during the warm-up phase, the power plant consumes fuel without generating any income. In the case of load-following operation and/or up- and down-regulation, increased costs are incurred as a result of accelerated aging of components, which is induced by temperature-change stresses.

The case of western Denmark

Between 2000 and 2012 in western Denmark, the share of wind power increased from 15% to 40% of gross electricity consumption. Over the same period, the full-load hours of the central power plants in western Denmark decreased from around 4500 hours to around 3000 hours. Figure 17.1 presents the utilisation of central power plants in western Denmark, expressed as the use of capacity during a certain period in 1 year. It is clear that the production-duration curve has become steeper since Year 2000, i.e., utilisation of capacity has decreased. This has, of course, a significant impact on the profitability of such power plants.

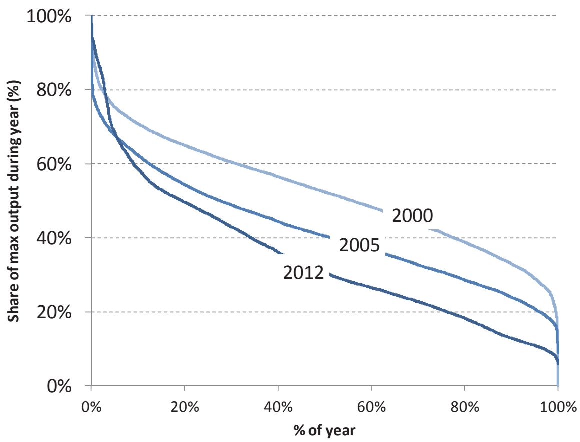

Figure 17.1. *Utilisation of central power plants in western Denmark, expressed as percentage of rated capacity during 1 year (e.g., in 2012, half of the maximum installed capacity was used in no more than 20% of the year, whereas in 2000, half of the capacity was used in 60% of the year). Source: Energinet.dk.*

In addition to causing lower utilisation, the cycling of the power plants, as discussed above, further increases operational costs. Figure 17.2 clearly shows the increased cycling of central power plants in western Denmark as the share of wind power has increased. The variations in collective output from central power plants are greater in Year 2012 than in

Year 2000. This means that some power plants need to be turned off more frequently or/ and some power plants need to run in part-load mode more often. Furthermore, the anti-correlation between wind power production and thermal power plant output is obvious. Apart from wind power and central power plants, there are also so-called ‘decentral’ power plants in operation in western Denmark. These are generally smaller units that are more tightly linked to district heating, which implies that they are not as flexible as central power plants (while central power plants also produce district heating they are primarily designed for electricity production).

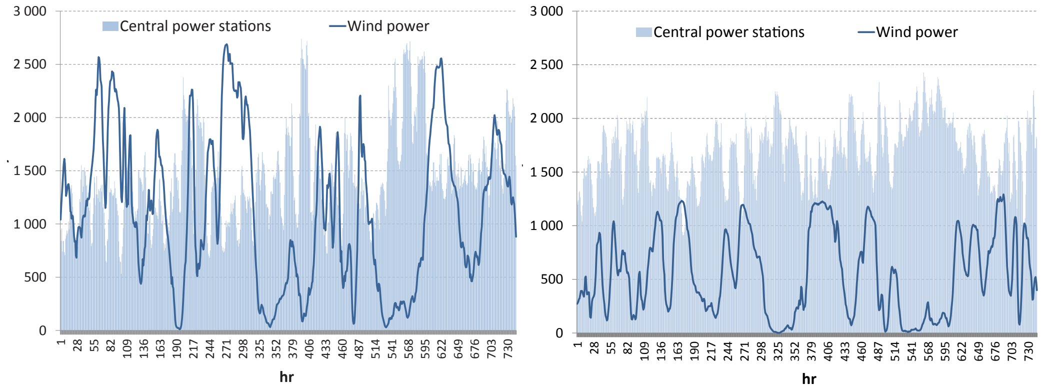

__Figure 17.2.__ Hourly electricity production by central thermal power plants and wind power turbines in western Denmark in Year 2012 (left panel) and in Year 2000 (right panel) during the month of January. Source: Energinet.dk.

Model findings

Modelling of the power system of western Denmark suggests that wind power variations introduce factors that influence the competitiveness of the thermal units in the power system relative to one another (Göransson and Johnsson, 2009). In general, simulations show that an increase in the level of wind power reduces the number and duration of periods of constant production. The capacity factors of units with high start-up costs and high minimum load levels (i.e., base-load units) will decrease more than the capacity factors of units with low start-up costs and/or low minimum load levels. While this result may appear to be trivial, high start-up costs and high minimum load levels are common properties of units with low running costs that are designed for base-load production. Thus, low running costs are generally incompatible with flexibility, and in a system with significant wind-power capacity, the unit with the lowest running costs is not necessarily the unit which is operated to the greatest extent. When comparing flexible but expensive gas-fired power with relatively inflexible but typically low-cost coal-fired power, the fuel cost difference becomes important. The narrower the cost difference between the higher gas price and the lower coal price becomes, the more gas-fired power will be utilised for reasons of flexibility at the expense of coal-fired power.

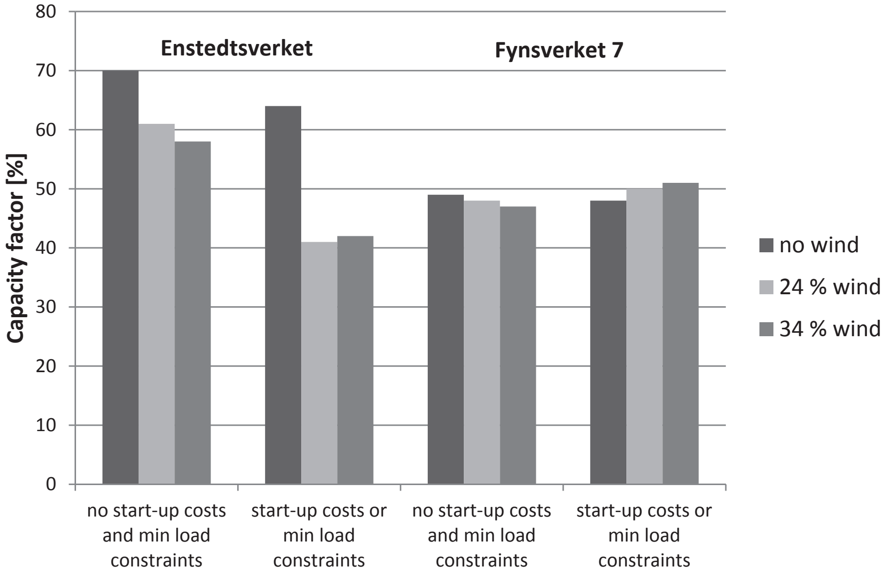

Figure 17.3. *Capacity factors of Enstedtsverket and Fynsverket 7, with and without the inclusion of start-up costs and minimum load level constraints, as wind power supplies an increasing share of the demand for electricity.*

An example of the increased competitiveness of power plants with better flexibility (or cycling properties) is shown in Figure 17.3, in which model simulations of western Denmark are reported for two different power plants with different cycling properties and using different fuels. The model simulations include different limitations related to cycling properties. As an example, Enstedtsverket is a large coal-fired power plant with low running costs. If start-up costs and minimum load limitations are excluded in the simulation, the Enstedtsverket retains a relatively high utilisation or capacity factor[1] even if wind power penetration levels are high (first group of bars from the left in the figure). However, if cycling limitations are included in the model simulation, the capacity factor of this power plant is dramatically reduced (second group of bars from the left in the figure) as the penetration level of wind power is increased. This is due to the fact that plants with inferior cycling properties are significantly affected, even if their running costs are low, as wind-power penetration levels increase. In contrast, Fynsverket 7 is a relatively small multifuel-fired power plant (block) with relatively high running costs and a significantly lower minimum load level than Enstedtsverket. In the absence of constraints on the cycling costs and minimum load level, the utilisation of Fynsverket 7 is reduced, albeit to a lesser extent than that of Enstedsverket owing to a lower initial capacity factor (third group of

[1] The capacity factor reflects the utilisation of a power plant, and is calculated as the ratio of the actual annual electricity generation to the maximum annual electricity generation at rated power.

bars from the left in Figure 17.3). However, if cycling costs and minimum load level constraints are taken into account, the capacity factor of Fynsverket 7 increases as wind-power penetration levels increase, since the plant replaces units that have poorer cycling properties, such as Enstedsverket (fourth group of bars from the left in Figure 17.3). This is a clear example of how variations in wind-power production change the dispatch order of the thermal units as wind-power penetration levels increase.

System estimates of cycling costs

In the present study, it is estimated that the total start-up costs for the western Denmark system with 20% wind power amounts to about 5% of the total system costs (i.e., running costs plus start-up costs). In the same analysis, the additional cost of cycling of a typical coal-fired power plant in western Denmark was estimated at around 1.5 €/MWh, given that wind power supplies about 55% of the total demand in that region. At lower wind-power penetration levels, e.g., 40%, the estimated cycling costs were reduced to roughly 1 €/MWh. However, it should be noted that this is a system-specific estimate (total increase in system costs due to the inclusion of cycling costs divided by electricity production); variations among individual power plants are large.

In the Western Wind and Solar Integration Study, in which wind and solar power generation supply 30% of the annual load in the Western Electricity Coordinating Council (WECC) system, it is concluded that start-up costs and part-load costs reduce the value of wind power by 0.1–2.4% (Jordan et al., 2012). IEA task 25 summarises the results from integration studies and concludes that for systems in which the wind power supply meets up to 20% of the annual demand for electricity, the costs associated with variability and uncertainty are in the range of 1–4 €/MWh. Hydro-dominated electricity-supply systems place themselves in the lower end of that interval.

Thus, from a system perspective, the cycling costs of thermal power plants may be considered as relatively low, even in cases in which wind power represents a considerable share of the demand (this is not the same as stating that the integration costs of wind power are low; in that case, it may be argued that additional costs, such as grid investments or costs related to back-up capacity, should be included). However, for individual power plants, the impact of increased cycling costs may be decisive, having the implications of permanent phase-out and stranded assets. In addition, in the absence of thermal power plants that act as regulating capacity and back-up for hours of poor wind and solar conditions, the success of large-scale integration of variable renewable electricity generation may be at risk. Large interconnected systems and combined investments in wind and solar power will reduce but not eliminate the number of hours of low vRES generation. In a market that deals exclusively with energy, hours of low vRES generation will be coupled with very high costs for electricity. These hours will increase the profitability of peak-load units and will likely stimulate demand-side management and storage investments. The questions remain as to whether investors in thermal power plants will be willing to invest in plants with few running hours (for which prices will necessarily be very high) and whether the public will accept very high electricity prices, even for a limited time period?

Recently, the concept of flexibilisation has emerged in relation to power plant operation (see, for example, an article by Klose and Prudlo, 2013). This underlying premise is that money can be earned by increasing the flexibility of a thermal power plant, especially with the prospect of increased variable electricity generation. Key investments to increase flexibility include reducing the minimum load level and improving the start-up phase.

Brief on the impact of solar power on thermal generation

To expand the scope, we also briefly reflect upon some characteristics of solar power and how that may affect other forms of electricity generation and the market for electricity.

From an aggregated perspective, solar power generation is highly correlated with demand. High-load hours typically occur during daytime when the sun is up and solar power can be generated. In the southern parts of Europe and the US, there is even a physical common between solar power and electricity demand, in that when it is sunny the electric load from air-conditioning is high while at the same time, solar power plants deliver at full capacity. In the absence of sunshine, the electric load from cooling devices is also reduced. Figure 17.4 illustrates the general correlation between the demand for electricity and solar generation for a low-voltage grid in Germany (ENERVIE AssetNetWork GmbH, 2013).

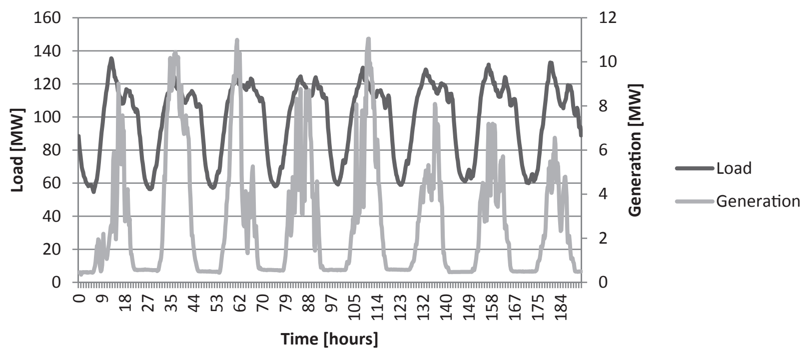

Figure 17.4. Generation (infeed) and load for a low-voltage grid in Germany. Source: ENERVIE AssetNetWork GmbH (2013).

Brief on the impact of solar power on thermal generation
(continued)

During peak-load hours, both peak-load and mid-merit loads are in operation, as well as base-load units. Solar power production will replace the units with the highest running costs first, in this case, these are typically peak-load units with flexible properties. If all units in operation are subject to significant start-up costs, it may suffice to reduce the operation of several units to part-load operation, so as to accommodate the solar power generated. Solar power can thus be integrated to some extent before it incurs start-up costs of any significance.

The dramatic increase in the use of photovoltaic (PV) cells in Germany has had a significant impact on wholesale electricity prices in recent years. PV production has narrowed the price gap between the base load and peak load. This is simply due to the fact mentioned above: PV production peaks as demand peaks. During the years in which the PV capacity has expanded by more than 30 GW, wholesale electricity prices between the hours of 08:00 and 18:00 have decreased in relation to prices applied during the night-time. Before the large-scale introduction of PV cells, mid-day prices were typically around 80% higher than the daily mean prices during the summer. Today, the corresponding difference is typically 15% (Hirth, 2012). In this case, and somewhat in contrast to the case of wind power, PV production has had a smoothing effect on the variability of wholesale electricity prices. This has created disincentives for investing in conventional peak-load capacity, e.g., gas turbines. The profitability levels of these units are largely dependent upon price differences between the peak-load and low-load segments.

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18 Allocation strategies to manage variability of wind power

In this chapter, we explore the possibilities and limitations of macro-geographical allocation as a means to improve the performance of aggregated wind power output. The focus is on spatial smoothing for improved wind conditions and on avoiding periods of low output of aggregated wind power. Three allocation strategies with different optimisation objectives are modelled and analysed. The results show that it is possible to allocate wind power so that the instances of low outputs are substantially fewer, while the average output is maintained at around 30% of name-plate capacity, as compared with 20% for the present allocation. We conclude that in a fully integrated Europe, there is almost no trade-off between avoiding low aggregate output and maximising total output or avoiding short-term spikes in output.

Different wind-power allocation objectives and strategies

Large-scale integration of wind power represents a challenge for the present energy system, and necessitates measures to deal with the variability inherent to wind-power generation. One possible measure would be to increase the transmission network so as to benefit from the advantages of distributed generation of wind power. Spatial distribution is likely to smooth the aggregated wind power output and provide benefits, such as:

i. lower balancing costs, due to the smoothing of variation on a sub-hourly to hourly time-scale; and
ii. lower costs for back-up power, due to an increase in capacity credit, i.e., an increase in the "firm" capacity of the total installed wind-power capacity.

Reducing the variability between longer periods of high and low output requires larger areas if a substantial reduction in variability is to be obtained. This is because wind conditions are determined by weather systems, which last for a few days up to several weeks. Managing the variations on a longer time-scale, i.e., avoiding extremely high and low outputs, would open possibilities to define part of wind-power generation as base load and to reduce the cost for back-up generation.

Reaping the benefits of spatial distribution requires an allocation strategy for wind power in the integration area. Thus, geographical allocation is one of the several important aspects in the integration of high levels of wind power in Europe. The research, reported on in this chapter, addresses the extent to which allocation of wind-power capacity can provide system benefits in the form of dampened variation of aggregated output. The approach is to *map the physical conditions that set the scene for the integration of wind power into the energy system.*

In this research, we investigate three different allocation strategies, which correspond to the following objectives:

1) **The High-output objective:** Wind power should generate as much energy as possible, which would entail placing the wind farms at those sites with the highest capacity factors.
2) **The Short-term variation objective:** Wind power should provide as smooth an output as possible, in order for other system components, such as consumption and thermal generation, to be able to minimise ramp-ups.
3) **The Avoid-lows objective:** Wind power should ensure a certain minimum level of output, so that the surrounding system can rely on wind power providing at least a certain part of the load. This objective is connected, albeit not synonymous, with the concept of capacity credit.

The different allocation strategies were analysed using an optimisation model and implemented for Europe (EU-27 plus Norway and Switzerland). In the model, Europe is subdivided into a total of 50 regions according to the definition of region applied in the regionalised version of EPOD (see *Methods* section). For all the allocation strategies, a total capacity of 250 GW was assumed to be distributed across the 50 regions (to fulfil optimally the different objectives). The maximum capacity density, which determines how much capacity can be installed in each wind power sub-region, was assumed to be 1 MW/km^2.

A detailed set of wind-speed data was translated to possible wind-farm outputs using a power output function. This function incorporates wake effects, availability, and electrical losses. It is designed to represent a future wind farm (2030), which means that technical developments related to cut-off wind speed are included, although no major efficiency improvement over that of present turbines is assumed. The wind-speed data are the ERA-Interim data for Years 2007–2009. The spatial resolution is 0.25 earth degrees[1], and the temporal resolution is 3 hours.

[1] Each data-point is assigned a pixel size of 0.25 × 0.25 degrees, which means that the sizes of the pixels correspond to land areas that range from 200 km^2 to 670 km^2.

The sites in each region are grouped according to capacity factor, so that sub-regions with different average wind-power capacity factors (40%, 35%, 30%, 25%, 20%, 15%, <15 %) are formed. Thus, each region has a maximum of seven sub-regions, while a typical region has three to four sub-regions within which wind power can be allocated.

Results from allocation strategies

Table 18.1 summarises the results of wind-power allocation using the three different optimisation strategies. In addition, these strategies are compared with two reference cases: the *Present allocation*; and the *Flat allocation*. For the Present allocation, wind power is allocated according to where the present capacity is situated (as obtained from the Chalmers power plant database). The Flat allocation assumes that an equivalent level of wind power is installed wherever it is windy (capacity factor >25%). The Flat allocation benefits from the smoothing effect, since it spreads wind power across Europe. However, as Table 18.1 shows, there is additional value to be gained from optimising the allocation. For instance, the High-output and Avoid-lows strategies both perform better than the Flat allocation reference case with regards to capacity factor and Value at Risk (VaR). Value at Risk is herein used as a measure of how high the poorest outcomes are, and the VaR value is improved by about 50% though optimisation (the Avoid-lows strategy), as compared to merely benefiting from the smoothing effect (the Flat allocation reference case). In addition, the Avoid-lows strategy has a higher capacity factor (31%) than the Flat allocation reference case (29%).

The comparison with the present system of allocation is more complex, since there are social and economic obstacles to installing wind power, which have not been taken into account in the optimisation. This partly explains the low performance of the present allocation, which has a capacity factor of 20%, although national subsidy programmes clearly influence the levels of investment.

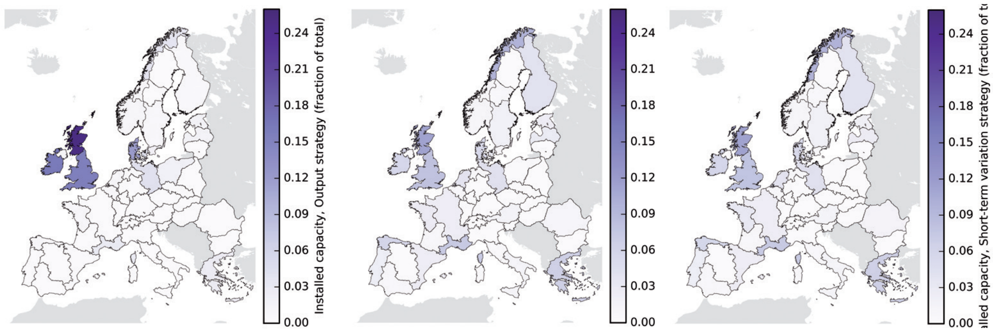
The Short-term variation strategy differs from the other strategies and cases in that wind power is curtailed. Depending on how much curtailment is allowed, the capacity factor drops accordingly. The characteristics of the Short-term variation strategy shown in Table 18.1 are for an allocation with a capacity factor of at least 25%. The VaR of this allocation is 16%, i.e., the same as that for the Avoid-lows strategy, while the maximum 3-hour change is only 7% of installed capacity, as compared with 12–22% for the other strategies and the Flat allocation reference case.

Table 18.1 Features of the three strategies for optimisation, and the reference cases.

	Optimisation strategies			Reference cases	
	High-output	Short-term variation	Avoid-lows	Flat allocation	Present allocation
Capacity factor (% of installed capacity)	34	25	31	2	20
Maximum 3-hour change in output (% of installed capacity)	22	7	12	18	15
VaR (% of installed capacity)	13	16	16	11	8
Minimum output (% of installed capacity)	3	5	5	2	1
Maximum penetration level of WP (in energy)	690 % (Scotland)	380 % (northern Norway)	600 % (northern Norway)	280 % (Scotland)	N/A
Number of regions with WP penetration level above 50 %	9	11	11	12	N/A
Number of regions with WP installation[a)]	25	34	34	32	46

[a)] Regions with wind power (WP) installations are here defined as those regions with more than 1/1000th of the total WP capacity, i.e., 250 MW in this case, since the total installed capacity is 250 GW.

Figure 18.1 shows the results for allocation space in the three optimisation strategies (Figures 18.1a-c). The High-output strategy results in the allocation with the highest concentration of capacity to certain regions (Figure 18.1c). This simple strategy "fills up" the windiest regions with wind-power capacity, which results in large installations on the British Isles, as well as on north-western mainland Europe. The installation is large compared to the load, with the maximum regional penetration level being almost 700% in Scotland (Table 18.1). The Short-term variation strategy gives very similar results for allocation space to that of the Avoid-lows strategy (Figure 18.1b-c). These strategies result in large installations in windy regions that are on the outskirts of Europe, for example, Greece, northern Norway, and the British Isles. Comparing the wind-power output with the load, northern Norway has the highest penetration levels, at about 600% for the Avoid-lows strategy and 380% (due to curtailment) for the Short-term variation strategy (Table 18.1).



a) b) c)

Figure 18.1. *Allocations resulting from the optimisation with: with: a) the High-output strategy; b) the Short-term variation strategy; and c) the Avoid-lows strategy. The maps show the allocations as fractions of the total installed capacity for each region. In the optimisation strategies, the total installed capacity is 250 GW.*

Figure 18.2 illustrates the aggregated time series for all of Europe according to the respective strategies. The time series for the Short-time variation strategy differs dramatically from the others in that the average and maximum outputs are lower, due to wind-power curtailment. In fact, in the extreme, all wind power above the minimum level (which is 5% of the installed name-plate capacity) can be curtailed, which flattens the output curve. The Short-term variation strategy can thus be adopted with different levels of curtailment, entailing different capacity factors. Thus, in Figure 18.2 and Table 18.1, a Pareto optimal allocation with at least 25% capacity factor is chosen. This capacity factor is considerably lower than those associated with the other strategies (about 30%). Comparing the High-output strategy and the Avoid-lows strategy, it is evident that the Avoid-lows strategy lacks both very low outputs (which was the essence of the associated optimisation objective) and very high outputs (which was not an optimisation objective but was the result nevertheless). The time series of the High-output strategy may vary from 20% to 80% output in less than 24 hours, while the time series of the Avoid-lows strategy displays considerably less dramatic shifts in output, an example of which can is shown in Figure 18.2 (lower right panel). The capacity factor for the Avoid-lows strategy is high (31%), albeit not as high as for the High-output strategy (34%).

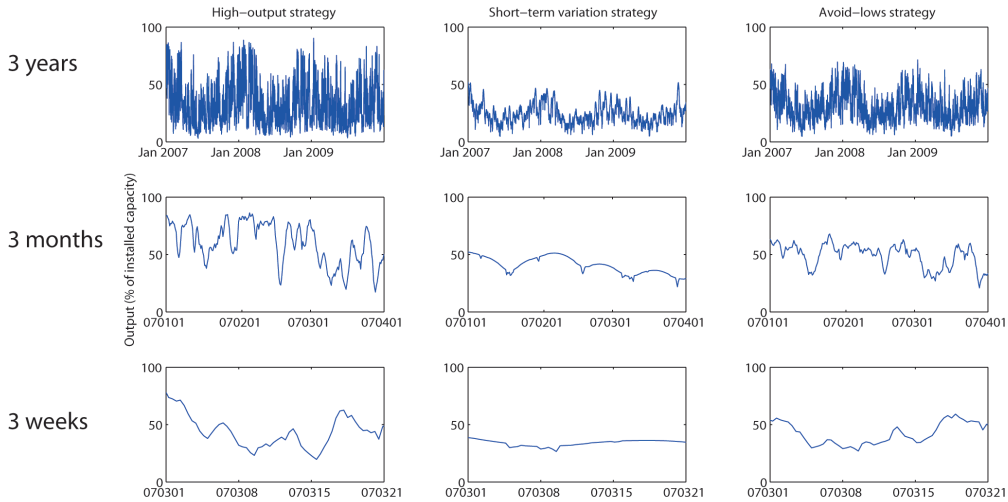


Figure 18.2. Aggregated time series for the three strategies (High output; Short-term variation; and Avoid-lows), which assume an integrated European market. The upper row shows the results for the entire period of 3 years, while the lower rows show the results for 3 months and 3 weeks, respectively.

Is there a trade-off between system benefits and average output?

All of the optimal allocations in the present work have high capacity factors. This may be a surprising outcome for those cases in which high output was not an optimisation objective. However, even the other objectives (Avoid-lows and Short-term variation) have inherent features that favour high output ("windy") sites. In the Avoid-lows strategy, the objective is to avoid a low output, which favours windy sites, since low output levels are rarer at windy sites. In the Short-term variation strategy, curtailment can reduce the peaks but cannot enhance low values, and so it is that this objective also favours windy regions. Therefore, there is no strict trade-off between system benefits and average output. In particular, when comparing to the average output of the present allocation of 20%, the typical output for the Avoid-lows strategy of 30% appears to be high. Thus, the results of the analysis indicate that there is a large potential to lower variability and avoid low output by planning the wind power allocation in an electrically integrated Europe.

This research was motivated by our wish to understand the physical conditions for wind-power integration, independently of the present surrounding energy system, which is the result of interactions between numerous factors over the years, such as political decisions and barriers, e.g., public acceptance. Mapping the physical conditions facilitates a better understanding of the demands that will be placed on the energy system if wind power is to become a large fraction of electricity generation. The physical potential to dampen variation and to provide a more reliable wind-power output may thus be the foundation for future decisions that take the broader system into consideration.

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19 A geospatial technological comparison of solar power

With the goal in mind of determining the geo-economic potential of solar technologies, the next step after an analysis of the resource potential for each technology (see Chapter 9), is to estimate the technological performance potential based on that resource. In this analysis we have created bottom-up models of a representative sample of currently commercialised and near to commercialised technologies in the distributed solar thermal and solar electric areas. We model a total of seven system types including flat-plate photovoltaics (PV), high concentration photovoltaics (HCPV), flat-plate thermal, evacuated tube thermal, concentrating trough thermal, concentrating solar combined heat and power (solar CHP), and hybrid photovoltaic-thermal (hybrid PVT). These models are integrated into a simulation that uses typical meteorological year weather and atmospheric data to create a yearly time series of production of heat and electricity from each system over a quarter degree spaced longitude and latitude grid of Europe. Through this simulation various permutations of collector-types and technologies can be compared geospatially and temporally to determine the best technologies in each region. For example, we see that silicon solar cells show a significant advantage over thin-film cells in the colder climatic regions, but that advantage is lessened in regions that have high average irradiance. Thus, comparing solar technologies simply on cost per peak Watt, as is usually done when making purchasing decisions, misses these significant regional differences in annual performance.

The solar technology

Solar energy is harnessed today, in practice, by two main types of technology: photovoltaic (PV) systems convert the photons from sunlight directly into electricity in a semiconductor device, whereas thermal systems collect the light from the sun and either use the thermal energy directly or convert that thermal energy to electricity through a heat engine. These solar technologies are described below.

The solar photovoltaic cell

At the core of photovoltaic technology is the solar cell, or the material that converts the sunlight to electricity. The physical process behind solar photovoltaics is not in the scope of this chapter, but suffice it to say that a solar cell is formed at the junction between two semiconductor materials (of which there exists many varieties). Multiple such junctions can be arranged in series (or parallel) that have different abilities to absorb different wavelengths of light (corresponding to different electron band gaps). All of these variations, in the end, affect how much of the sunlight can be converted to electricity, with the goal to develop low-cost materials reaching the theoretical limit of efficiency. For a single junction cell this efficiency limit is approximately 30%, but increases to 42% for two-junctions, and 48% for three-junctions, with a theoretical limit of 68% achievable with infinite junctions. Under high concentration the corresponding limits are 40% for a single-junction cell, 55% for two-junctions, 63% for three-junctions, and an 86% theoretical limit with infinite junctions (De Vos, 1980).

A list of the most common solar photovoltaic chemistries used today in order of approximate market share (Masson et al., 2013) are: polycrystalline silicon (poly-Si), single-crystalline silicon (mono-Si), thin film amorphous silicon (a-Si), thin film cadmium telluride (CdTe), thin film copper indium gallium selenide (CIGS), and multi-junction cells. Silicon technologies are broadly divided into crystalline cells (single or polycrystalline), which make up over 80% of the market, and non-crystalline cells (amorphous). Amorphous cells are generally thin-films, meaning a thin layer of the semiconductor material is deposited on a base layer. This process reduces cost by reducing the amount of material used in the process, but also decrease the efficiency of the cell compared to crystalline silicon cells. CdTe and CIGS cells are other examples of commercial thin film technology. At the top end of the spectrum, in terms of efficiency, are multi-junction cells, the most advanced of which are generally made up of layers of compounds of group III and V elements on the periodic table. We model the most common cell types (i.e. poly-Si, mono-Si, CdTe, CIGS, multi-junction) in this analysis. An example of typical year electrical production for a flat-plate mono-Si PV system over all of Europe is shown in Figure 19.1.

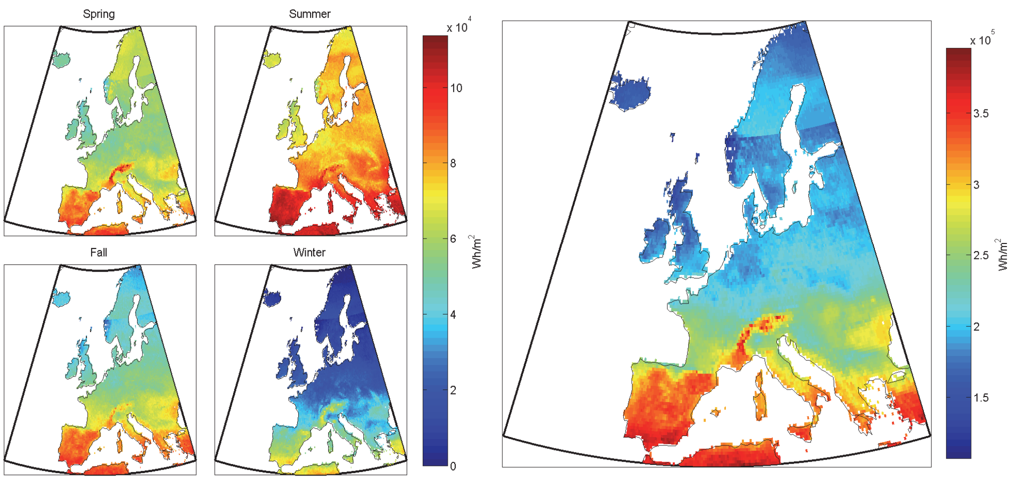


Figure 19.1. *Flat-plate mono-Si PV electricity production for one square meter of collector (left) seasonally and (right) annually. Note that the line visible at about 63 degrees north latitude (mid Sweden) is an artifact of differing solar data sources, but that the solar data is still within 18% accuracy to the nearest ground station data at all locations. Source: Remund and Müller (2012).*

In concentrating photovoltaic systems (CPV), the cells are packaged together into a module and usually many modules are mounted on a tracking apparatus where each individual cell is illuminated with highly concentrated sunlight that can be greater than one thousand times as bright as direct sunlight. Commercially, high concentration photovoltaics (HCPV) usually use Fresnel lenses but concentration can also be accomplished with any of the concentrating collector geometries described in the thermal and thermal-electric sections. We model a typical example of an HCPV collector in this analysis (Burroughs et al., 2013), with electrical production over Europe for a typical year show in Figure 19.2.

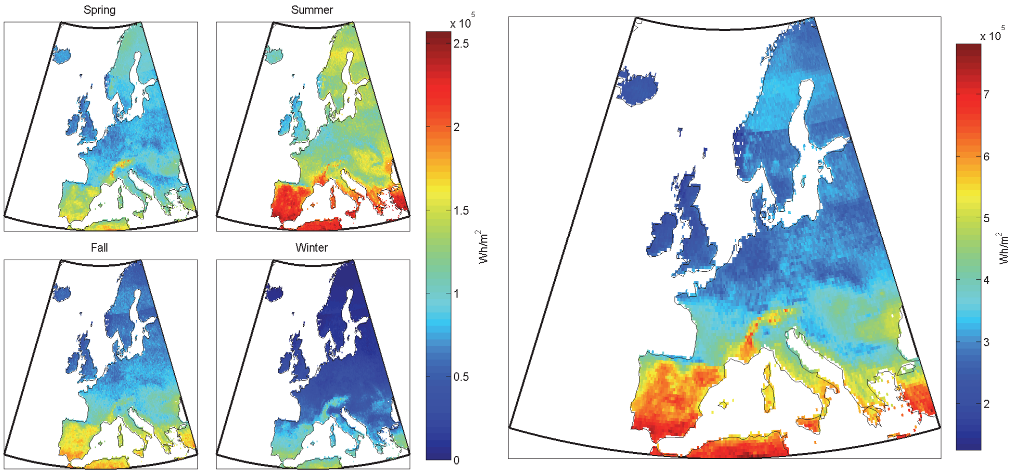


Figure 19.2. *HCPV electricity production for one square meter of collector (left) seasonally and (right) annually.*

Solar thermal

At the other end of the solar technology spectrum from photovoltaics is solar thermal technology which collects sunlight and converts the energy to heat. Solar thermal systems use fluids (usually water or a glycol-water mix) to transfer the heat from the collector to a storage tank where it is then used for anything from industrial process heating to domestic hot water and space heating. The main commercialised types of solar thermal systems are those using flat-plate collectors, evacuated tube collectors, and concentrating trough/dish collectors.

Flat plate collectors can be glazed or unglazed. Glazed collectors are insulated on all sides except the glazing (a transparent single or multi-layer) which is facing the sun and allows the sunlight to come in but limits the losses due to convection going out (like a mini greenhouse). The absorber is usually made of copper or aluminum with many channels for the fluid to run through and a selective coating to prevent reflection of the light. Unglazed collectors are often made of plastic polymers, and are usually more appropriate for lower temperature heat demands and warmer climates.

Evacuated tubes are designed like a transparent thermos, where a long cylinder of glass surrounds the channel that the fluid moves through. The space between the glass and the fluid is a near-vacuum to minimise convective losses. The fluid itself is sometimes designed as a heat-pipe allowing for efficient transport of higher temperature fluid to a header where it heats the main circulating fluid in the system. Evacuated tubes have the other benefit of having a higher acceptance of diffuse light due to their cylindrical shape preventing reflection of light from oblique directions.

Concentrating trough and dish collectors use reflective surfaces in parabolic-like shapes to reflect the sunlight onto an absorber, the main difference between a dish and trough being that a dish is a 3-dimensional parabola (or non-imaging parabolic shape) whereas a trough is only a parabola in 2-d. Because the incident amount of sunlight per surface area is higher for a concentrating collector, and the corresponding thermal losses are lower due to lower surface area, higher temperatures can usually be obtained with this type of collector than with any of the others, especially if the absorber is itself enclosed in an evacuated tube. As they are the main commercialised products for moderate and high temperature solar thermal, we model glazed flat-plate collectors, evacuated tubes, and concentrating troughs in this analysis. Typical year thermal output for a glazed flat-plate collector is shown in Figure 19.3.

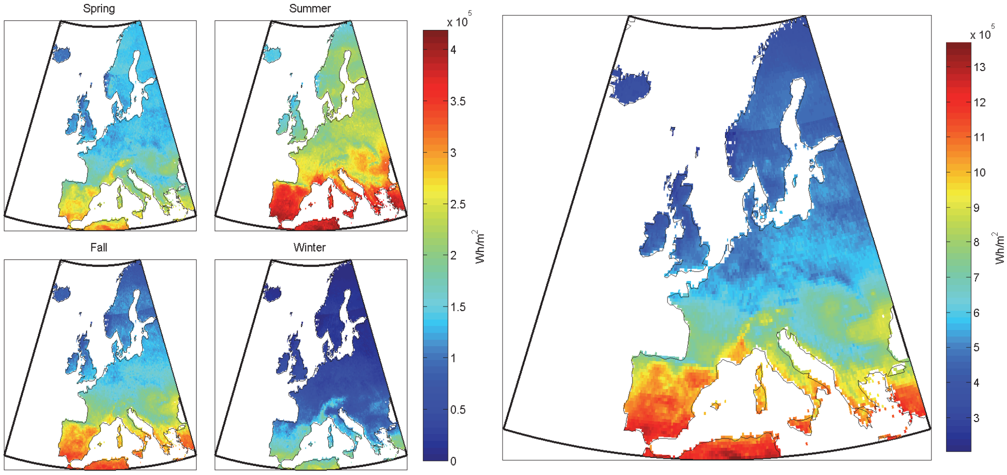


Figure 19.3. *Flat-plate thermal system production of heat for one square meter of collector (left) seasonally and (right) annually.*

Solar thermal-electric

Systems that convert sunlight to thermal energy and then to electricity are usually called "concentrating solar power" (CSP) although, as mentioned above, the same concentrating optics could also focus the sunlight on PV cells (CPV) instead of heating a thermal fluid. The scale of CSP systems is usually very large (i.e. power plant), but smaller systems can also be designed, for example, in remote villages for rural electrification. Solar thermal-electric systems offer the advantages of being suitable for operation on other combustible fuels when the sun is not shining, and can store energy as thermal energy to later be converted to electricity. This method of storing energy thermally is generally less expensive than storing electricity directly.

The general principle behind solar thermal-electric systems is that a working fluid (usually a molten salt, mineral oil, or water) is heated to high temperatures at the focus of a concentrating solar collector, and the energy from that hot fluid is then used to run a heat engine. The heat engine is usually based on either a Rankine cycle (the same cycle used in most fossil-fuel power plants) or a Stirling cycle.

In the most common cycle, a Rankine cycle, a fluid (usually water) is compressed, boiled, expanded (usually in a steam turbine) where it drops in temperature and pressure in the process of producing mechanical work, and then condensed back to liquid again before starting the cycle over. The mechanical work generated by the turbine in the process is converted to electricity by a generator.

To get the high temperatures needed to operate the turbine efficiently, solar thermal-electric systems usually use concentrating solar collectors which can produce fluid temperatures from a couple hundred to over a thousand degrees Celsius. These collector systems can generally be categorised as one of four types: Parabolic trough, linear Fresnel, dish engines, or central receivers. For the purposes of this analysis, only parabolic trough systems are included, although the performance would be comparable to that of a linear fresnel or dish system based on a Rankine cycle at the same temperatures we model here (500 K max fluid temperature). We exclude central receiver systems and solar stirling engines from this analysis as they are not well-developed at smaller scale.

Hybrid photovoltaic-thermal systems

An area of expanding research in the field of solar power is so called hybrid photovoltaic-thermal (hybrid PVT) systems. These systems combine a thermodynamic heat engine cycle, like in CSP, with a photovoltaic material to boost the overall conversion efficiency of sunlight to electricity. For example, one such system would use an optically selective fluid (e.g. with suspended nanoparticles) running over a photovoltaic material at the focus of a concentrating solar collector. The fluid would mainly absorb those wavelengths of light that were not useful to the PV, thereby allowing the useful wavelengths to hit the PV, while the other wavelengths heat the thermal fluid to high enough temperatures to run an additional heat engine cycle to produce electricity. The overall solar-electric efficiency

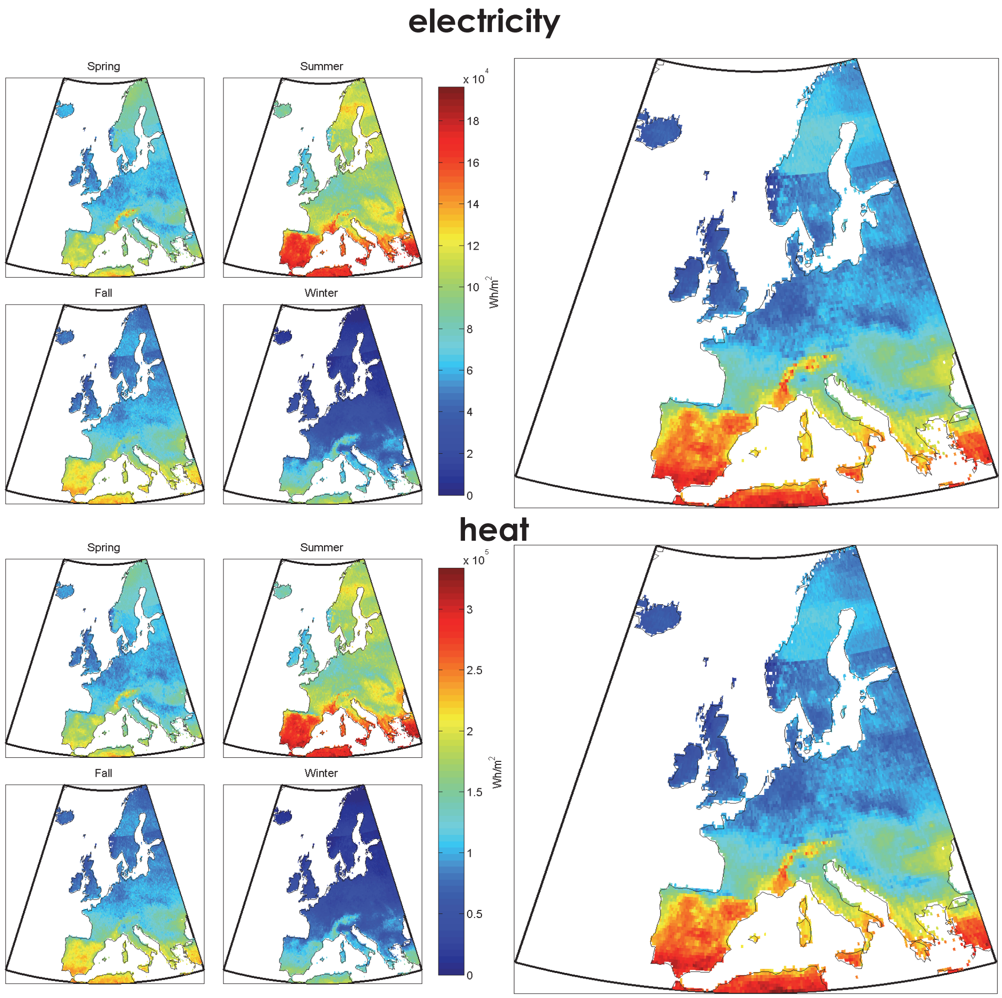


Figure 19.4. *Hybrid PVT production for one square meter of collector of electricity (top) and heat at 370 K (bottom), both seasonally (left) and annually (right).*

from such a system could be higher than either a CSP or PV system alone. In collaboration with Prof. Todd Otanicar at the University of Tulsa, Oklahoma, we model this technology (Otanicar et al., 2011), with thermal and electrical production shown in Figure 19.4.

Geo-technical comparison of solar production

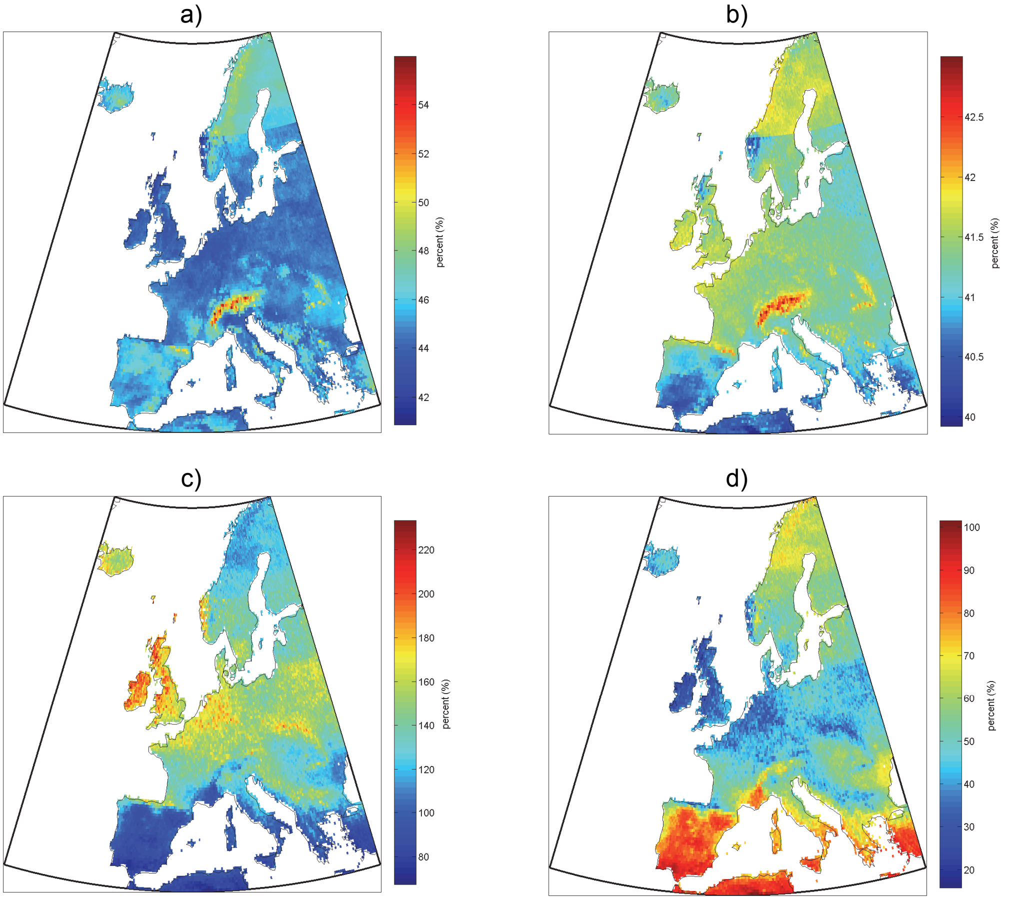
Electricity production

Modelling and comparing each of the technologies in Figure 19.1, 19.2 and 19.4 with the same framework across all of Europe offers some interesting insights. Figure 19.5a, for example, shows that the relative temperature sensitivity of silicon cells (which exhibit greater performance degradation as cell temperature increases compared to CdTe) gives them a significant advantage (up to a 54%) in the colder climatic regions such as in the alps, and northern Scandinavia, but that advantage is lessened by their greater performance increase with increasing irradiance (as compared to CdTe a 44% advantage) in regions that have high average irradiance, like Spain. Figure 19.5b, comparing mono-Si to CIGS, shows less of these effects as both the temperature and irradiance performance dependence are more similar between the technologies. Furthermore, although the efficiency at standard temperature and conditions (STC is 25^{o} C and 1000W/m^{2}) for CIGS is more than 12% greater than CdTe, the typical annual production is less than 4% greater in the vast majority of Europe due to these differences in temperature and irradiance effects.

Comparing mono-Si PV to a thermal-electric steam Rankine cycle at moderate temperatures (500K, isentropic efficiency of expander of 80%), in Figure 19.5c, shows that PV increases total electric production by at least 50%, but that the greatest increases (of over 200%) are in the cooler areas of lowest direct radiation, including the British Isles, and much of the region at latitudes south of Scandinavia and north of the alps.

Comparing hybrid PVT to mono-Si in Figure 19.5e shows the same relative trends, but of course the total production in most locations is greater for the PVT technology (-5% to 50%), yet notably hybrid PVT shows the greatest comparative benefit in the north of Scandinavia, and southern Europe. In the north this is due to a combination of a high fraction of direct normal irradiance (DNI) being good for concentrating systems, and low ambient temperatures being good for PV efficiency. In the south, the increased performance of hybrid PVT is due mainly to the higher fraction of DNI being good for the concentrating system, compared to the flat-plate PV.

Figure 19.5d comparing HCPV to mono-Si shows that the increased base-efficiency of the multi-junction cell in the HCPV system only gives it a 20% increase in total system efficiency in the areas with the lowest fraction of DNI, but over 100% increase in total system efficiency in areas with the highest fraction of DNI compared to diffuse irradiance, which occurs both in northern Scandinavia and latitudes south of the alps.



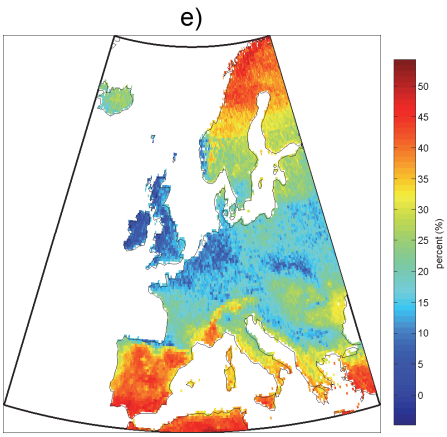


Figure 19.5. *Comparison (in percent) of annual electricity production per square meter of installed collector for several representative solar-electric systems a) mono-Si to CdTe thin-film b) mono-Si to CIGS, c) mono-Si to solar CHP Rankine d) HCPV to mono-Si e) hybrid PVT to mono-Si. Note that the reference case is always listed last (e.g. "mono-Si to CdTe" is the mono-Si percent increase or decrease from the CdTe system's production).*

Thermal production

In the comparisons between thermal output for various systems, the results generally follow the same trends as with thermal-electric. Figure 19.6a shows that evacuated tube thermal production exceeds that of flat-plate in all of Europe, but is greatest (25%) in the coldest and cloudiest regions, and least (< 5%) in the warmest regions. Clearly the decreased thermal losses of the evacuated tube design seem to give it the biggest advantages as compared to its increased ability to collect diffuse radiation as demonstrated by the evacuated tube's strongest comparative performance in the coldest regions, even those with a high fraction of DNI.

With the trough thermal system comparison to flat-plate collectors, as shown in Figures 19.6b-d, the trends show the greatest increase in system production in areas with the highest DNI and coldest temperatures, as would be expected for all concentrating systems. Figures 19.6c-d show the thermal output for the thermal-electric systems compared to that of a flat-plate thermal-only system, so in both cases one can see that the total heat output of the thermal-electric system is comparatively less because a significant fraction of the thermal energy has been converted to electricity. In fact, comparing Figures 19.6c-d shows that the average decrease in heat output of 10-15% of the hybrid PVT system compared to the solar CHP system correlates well with the average doubled relative electrical output of the hybrid PVT system (i.e. an additional 10-15 percentage points of the sunlight is converted to electricity in the hybrid PVT system, for a total of 20-30% solar-electric conversion).

In summary, we can see that in terms of both electricity and heat production that the solar technology type can play a large role in the total amount of useful energy that can be collected. Therefore, it is important to consider the regional climate where a system will be installed, instead of comparing technologies based simply on rated power (as is often done). These regional climate differences are, in many cases, of large enough magnitude to shift the most cost-effective technology type from one region to the next. Continuing work to specify the technology costs in the models will allow us to further understand the market competitiveness of these technologies in comparison to one another.

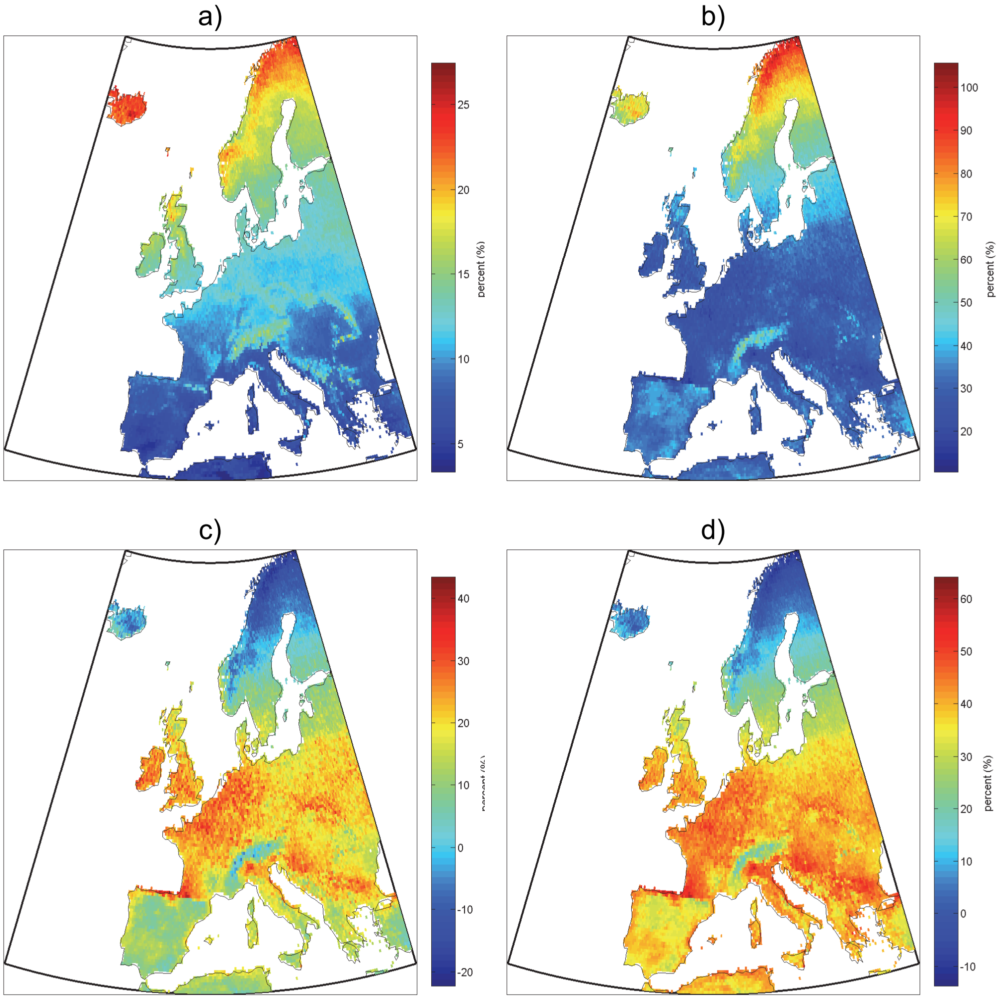


Figure 19.6. *Comparison (in percent) of annual thermal production per square meter of installed collector for several representative solar-thermal systems: a) evacuated tube to flat-plate, b) concentrating trough to flat-plate, c) flat-plate to solar trough CHP d) flat-plate to hybrid PVT. Note that the reference case is always listed last (e.g. "evacuated tube to flat-plate" is the evacuated tube percent increase or decrease from the flat-plate system's production). Note also that modeled average output temperature from the PVT and CHP system is 370K compared to 325K from the thermal-only systems.*

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20 The future role of Nordic hydropower

It is highly likely that hydropower will take on an increasingly important role as the shares of variable and non-dispatchable renewable electricity increase. Central to this development will be the hydropower-rich countries, such as Norway and Sweden. Traditionally, hydropower has been a superior supply option to handle variations in load. In the future, the ability to handle variations at the supply side, i.e., variable renewable generation from wind and solar power, will become equally important. The results of modelling show that in particular Norwegian hydropower, due to its extensive storability, will act as a distributor of electricity, both geographically and temporally. This possibility emerges at a time of both increased penetration of variable renewable electricity generation and increased integration of the European electricity markets through additional interconnectors. Thus, almost 20 TWh/year of Swedish and Danish electricity generated during hours with good wind conditions are redistributed by Norwegian hydropower to meet peak-load hours in the UK and central Europe. Furthermore, almost 10 TWh/year of peak-load power in Denmark, the Netherlands, Germany, and the UK are redistributed by Norway to low-load hours in these countries. A prerequisite for this development is, of course, that investments are made in new interconnectors between the Nordic electricity market and continental Europe and the UK.

Towards 20% variable renewable electricity and new interconnectors across Northern Europe by Year 2025

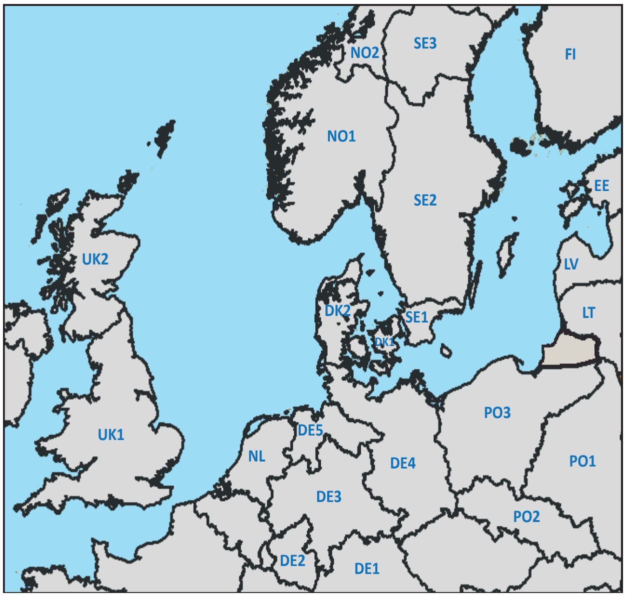
According to national renewable action plans, the share of renewable electricity in the EU-27 by Year 2020 will be approximately 35%. These same plans project that solar and wind power will generate approximately 15% of gross electricity consumption. The modelling presented in this chapter assumes that the corresponding share of variable renewable electricity sources (vRES; primarily comprising solar and wind power) is almost 20% by Year 2025. In some regions of Northern Europe, e.g., Scotland, Denmark, and Northern Germany, the share of vRES significantly exceeds 20%. However, hydropower is assumed to be limited to existing capacity across all the Member States, Norway, and Switzerland. This corresponds to around 35 GW in Norway and around 16 GW in Sweden. Hydropower production in a normal year amounts to 120 TWh in Norway and 70 TWh in Sweden. Given the annual variations in precipitation, hydropower production in these two countries can vary significantly. This is taken into consideration in the present analysis, presented in this chapter, which includes both wet- and dry-year conditions. During a wet year, hydropower can generate up to 140 TWh in Norway and 80 TWh in Sweden. During a dry year, hydropower can generate around 105 TWh in Norway and 50 TWh in Sweden.

New transmission capacity assumed

In the analysis, new interconnector capacity is expected by Year 2025. Table 20.1 lists the high-voltage direct current (HVDC) connections that are currently in place between the Nordic countries and continental Europe, as well as the HVDC connections that are exogenously added until 2022 in the ELIN model, corresponding to those currently in the planning phase. The HVDC connections from Norway to Denmark, Germany, and the UK are planned to be in operation by 2014, 2018, and 2020, respectively (Statnett, 2013). The western HVDC link, which will reinforce the connection between Scotland and England, is planned to be completed in Year 2016 (WesternLink, 2013). The German transmission corridors have been approved by the German federal network agency (Bundesnetzagentur, 2011).

Table 20.1. *High-voltage direct current (HVDC) connections between the Nordic countries and continental Europe, and HVDC connections that are planned (in italics).*

Region 1	Region 2	Capacity (MW)
NO1	NL	700
NO1	DK2	1000
SE1	DE4	600
SE2	DK2	740
SE1	PO3	600
SE1	LT	700
NO1	*DK2*	*700*
NO1	*DE4*	*1400*
NO1	*UK1*	*1400*
DE1	*DE4*	*4000+2000*
DE5	*DE2*	*2000*
DE2	*DE1*	*2000*
UK1	*UK2*	*2000*



Model results on cross-border electricity trade

To study the role of Nordic hydropower the modeling package of ELIN/EPOD is applied (see also the Method section). The ELIN model gives the long-term development of the European power plant fleet, and the operation of the system in Year 2025 is analysed in detail using the EPOD dispatch model. Trade between the hydropower-dominant regions (NO1, NO2, NO3, SE3 and SE4) and neighbouring regions is governed by the storability of hydropower, the limitations of the hydropower resource, and the resource-to-capacity relationship of hydropower. The storability and "over-capacity" of hydropower allow it to replace the most expensive units in the neighbouring systems. In SE3 and SE4, the hydropower resource exceeds the local demand for electricity, and these regions rarely import power. However, in NO1, where the yearly hydro inflow under normal-year conditions is sufficient only to cover the local electricity demand, increasing the hydropower output during certain hours to supply neighbouring systems results in an increase in thermal production during other hours of the day in any of the trading regions. By Year 2025, the electricity load still has a major influence on the marginal cost to generate electricity in the British, Dutch, and German electricity generation systems. However, the marginal cost of generation is influenced by wind power generation and, especially in the Danish system, wind power generation strongly influences the marginal cost of generation.

Figure 20.1 presents the trade between DE4 and NO1 for three summer weeks of Year 2022, as well as the wind power generation and load levels in DE4. The figure shows that DE4 imports electricity from Norway during peak-load hours, whereas DE4 exports electricity to Norway during high-wind, low-load events. Under dry-year conditions, electricity is exported to Norway during all low-load events (i.e., every night), while export to Norway only takes place under high-wind conditions during wet years. The UK shows similar patterns, albeit with shorter export events. Trade between the Netherlands and Norway is similar to that shown for dry-year conditions in Figure 20.1, i.e., diurnal export during low-load hours. The trade between Denmark and Norway is characterised by days of export from Denmark to Norway during good wind conditions, interrupted by periods of diurnal import to Denmark to cover peak load during hours of low wind-power generation.

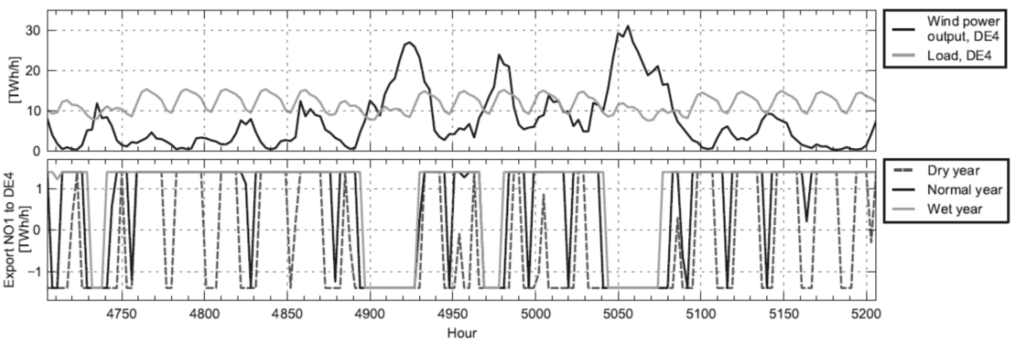


Figure 20.1. *Trade between DE4 and NO1 for three weeks in the summer of Year 2022, as obtained from the EPOD modelling. Negative trade indicates export from DE4 to NO1. The wind generation and load levels for DE4 are added for comparison. Source: Göransson et al. (2013).*

Figure 20.2 depicts the yearly net exports of electricity in Year 2025, as obtained from the EPOD modelling for the regions investigated. The large expansion of wind power in northern Germany and northern UK yields large net exports of electricity from DE4, DE5 and UK2. Northern Sweden (SE3 and SE4) traditionally supplies southern Sweden with electricity. However, due to investments in wind power (corresponding to an additional wind power production of 6 TWh/year in SE1 and 6 TWh/year in SE2, as compared to Year 2012) and investments in gas-fired combined heat and power (CHP) in the south of the country, the modelling shows that by Year 2025 Sweden becomes a net exporter of electricity. By then, Denmark is also a net exporter, since the modelling assumes that a large part of the thermal capacity remains in operation despite additional wind investments. From the modelling results, it can be concluded that through import/export across the interconnectors, electricity generated in Sweden, Denmark, northern Germany, and northern UK is redistributed to the UK, southern Germany, and regions close to the German border, such as Austria and Switzerland.

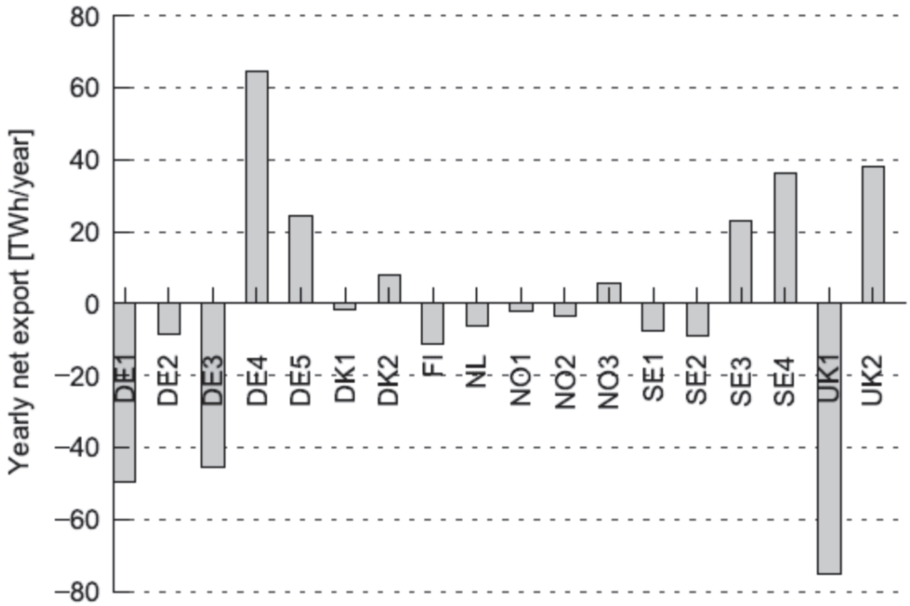


Figure 20.2. *Yearly net exports in model Year 2025, as obtained from the EPOD modelling for the regions investigated. Source: Göransson et al. (2013).*

Norwegian hydropower as a geographical re-distributor of electricity

The results of the analysis presented in this chapter have important implications for the role of Norwegian hydropower. In general, Norwegian hydropower provides a better balancing resource than Swedish hydropower because: 1) the capacity of Norwegian hydropower is more than twice that of Swedish hydropower; 2) Norwegian hydropower production is located close to Norwegian interconnections with Europe, whereas Swedish hydropower is limited not only by the availability of connections to continental Europe, but also by the internal transmission capacity between northern and southern Sweden; and 3) since the Swedish electricity generation system encompasses 9.3 GW of nuclear power with high minimum-load levels and high cycling costs, Swedish hydropower is reserved for domestic consumption to a greater extent than is Norwegian hydropower.

Hydropower plays a central role in the matching of generation to load in wind-thermal systems and in realising the electricity redistribution shown in Figure 20.2. The model results indicate that in Year 2025, Norway exports 6.5 TWh/year to Germany, 2.7 TWh/year to the Netherlands, and 8.6 TWh/year to the UK under normal-year conditions for hydropower. The Danish system supplies Norway with 8.5 TWh/year of electricity. Of this, about 3.6 TWh/year is of Swedish origin. In the base Year 2012, Sweden imports 5.0 TWh/year from Norway, while Sweden exports 8.6 TWh/year to Norway (both directly and via Denmark) by Year 2020. Thus, while the Norwegian net export is relatively small, the geographical re-distribution executed through the operation of Norwegian hydropower is significant.

Norwegian hydropower as a temporal re-distributor of electricity

Trade with Norway also allows the temporal redistribution of electricity within a region. The trade has in this case the same role as demand-side management, where the load during peak-load hours is served by Norwegian hydropower, while the trading region supplies the load in Norway during low-load events. Trade of this type encompasses 1 TWh/year in Denmark, 2.7 TWh/year in northern Germany, 1.7 TWh/year in the Netherlands, and 1.7 TWh/year in the UK. For the base year (Year 2012), the modelling gives that the Nordic countries import electricity from Denmark and Germany during high-wind, low-load events, whereas importation from the Netherlands is only sporadic. Data on trade from Nord Pool from Year 2012 (Nordpool, 2013) also show recurring imports of electricity from Denmark to Norway, while imports of electricity from the Netherlands to Norway are much less frequent. In the base year (Year 2012), the UK and the Netherlands typically have much higher marginal costs for generating electricity, even during low-load hours. However, by Year 2025, the model shows recurring imports of electricity from the UK and the Netherlands to the Nordic countries during high-wind, low-load situations, and that the marginal costs of generation in the southern parts of the Nordic countries are equal to the marginal costs of generation during high-wind, low-load hours in the UK and the Netherlands. During dry years, with much reduced hydro power capabilities in the Nordic countries, Norway is still exporting electricity to Germany, the Netherlands, and the UK during peak-load hours. However, the yearly net export levels from Norway to Germany, the Netherlands, and the UK are reduced to 2.5 TWh/year, 1 TWh/year, and 6.5 TWh/year, respectively. At the same time, Norway redistributes more electricity in time in Germany, the Netherlands, and the UK under dry conditions, as compared to under normal hydrological conditions. For wet years, the model gives only occasional imports from Germany and the UK to Norway and yearly net exports from Norway of 10.5 TWh/year and 10.1 TWh/year, respectively, to these two countries. For wet years, the export to the Netherlands in Year 2022 is back to the reference year level of 5 TWh/year, while Norway remains an importer of Danish electricity. Norway redistributes more electricity in time in Denmark under wet conditions than under normal hydrological conditions.

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21 Co-firing biomass as a bridging technology

Electricity production from solid biomass in the EU-27 increased by almost 40% (or 22 TWh) in the period 2008–2012, reaching almost 80 TWh in Year 2012. In Poland, the UK and the Netherlands, production increased by 12 TWh, corresponding to 55% of the increase for the EU-27. The research conducted and reported in the present chapter shows that co-firing biomass in existing coal-power plants has played an important role in these three countries. In the short-term perspective (approximately 5 years), plans for co-fired/fully converted coal-power plants could increase solid biomass electricity production in the EU-27 by an additional 30–35 TWh, thus act as a bridging technology towards a sustainable energy system. Furthermore, this research shows that there is a strong potential to increase even further electricity production from solid biomass by expanding co-firing and/or full conversion of coal-power plants in Germany, Spain, France, Romania, Greece, and Bulgaria.

Electricity production from solid biomass is growing in Europe

During the period 2008–2012, electricity production from solid biomass in the EU-27 has increased from 58 TWh to almost 80 TWh, i.e., by almost 40%.

It is interesting to note that the three largest producers of solid biomass-fired electricity, Germany, Finland, and Sweden, have had relatively slow growth rates (8 %) during the period 2008–2012. This means that their shares of the total production of solid biomass-fired electricity decreased from 52% in Year 2008 to 41% in Year 2012. The total increase in production for these three countries amounted to 2.5 TWh.

From the statistics, it is possible to identify six countries that experienced both a growth rate of >50% and an increase of ≥1 TWh for solid biomass-fired electricity between 2008 and 2012 (c.f. Figure 21.1). Overall, solid biomass-fired production of electricity increased by 16 TWh (115%) in these countries, corresponding to 73% of the total increase for the EU-27. Poland and the UK had by far the largest growth rates for solid biomass-fired electricity, 196% and 155%, respectively, resulting in a total increase in electricity production of 10.6 TWh.

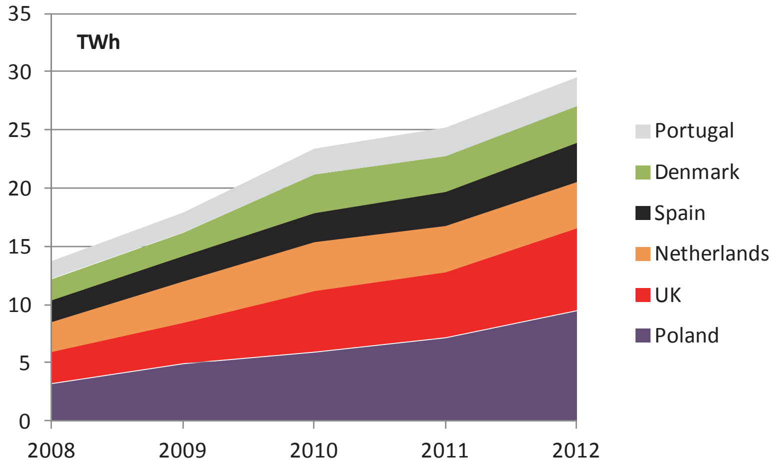

Figure 21.1. *Development of solid biomass-fired electricity (gross) production in Poland, the UK, the Netherlands, Spain, Denmark, and Portugal in the period 2008–2012, according to data from Eurobserver (2010; 2011; 2012 and 2013)*

Using existing coal power plants as a way to increase solid biomass-fired power production

Several options are available for increasing solid biomass-fired electricity production. In countries with pulp and paper industries, production can be increased by expanding and developing the use of back-pressure options, whereby by-products (e.g., black liquor, bark, saw dust, and logging residues) are used. Where district heating is available, new CHP plants that use biomass represent an option for ensuring efficient use of the fuel content. Where there exists neither a need for district heat nor a need for heat as process energy, new biomass-condensing plants could be an option[1].

Another option is to make use of existing coal-power plants and their infrastructures, either by co-firing biomass with coal (typically in the range of 10%–20% by energy content) or to convert old coal-power plants/units to 100% biomass-fired plants. The technical potential for co-firing biomass in coal-power plants has previously been investigated by Hansson et al., (2009). That study used the Chalmers Power Plant Database (CPPD), which contains information on the power plants in the EU-27 (see Method section). Hansson et al. used Year 2007 as the reference year and evaluated the technical potential for co-firing biomass in the following cases (including both hard coal and lignite):

- **Case 1:** where boilers commissioned in 1967 or later (i.e., those <40 years old in 2007) were assumed to be available for co-firing

[1] At least with increased efficiency and/or high CO_2-prices.

- **Case 2:** where boilers commissioned in 1977 or later (i.e., those <30 years old in 2007) were assumed to be available for co-firing

Figure 21.2 illustrates the *potential* capacity for co-firing in Year 2007, as identified in Cases 1 and 2 (Hansson et al., 2009). Case 1 included about 90% of the capacity of the existing EU-27 coal-fired power plant infrastructure. Case 2 represented a less-optimistic scenario for co-firing (corresponding to the use of about 50% of the installed capacity).

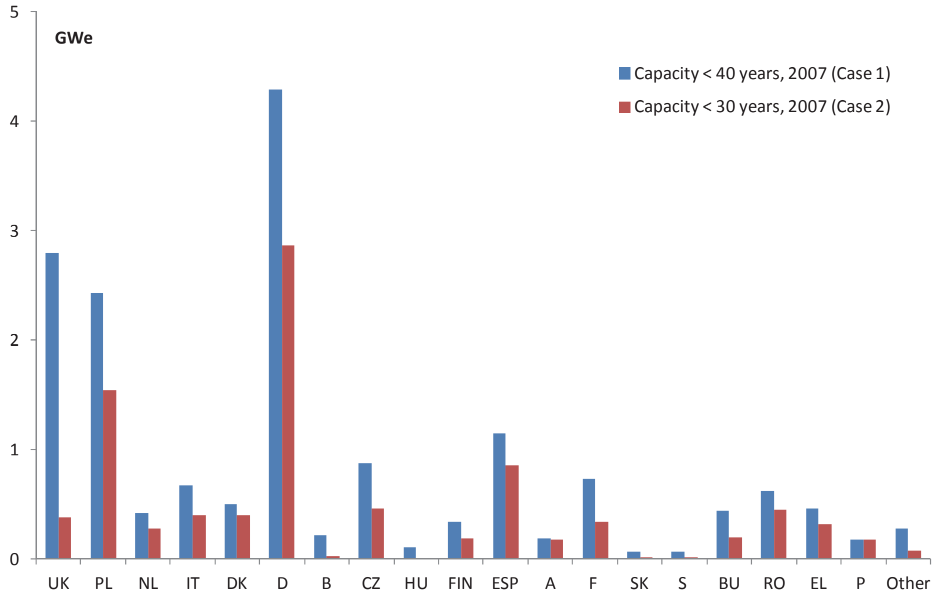

Figure 21.2. *Potential biomass net power capacities in Year 2007 through co-firing, as identified in Cases 1 and 2 of Hansson et al. (2009).*

To estimate the potential for electricity production using solid biomass in co-firing schemes, the following assumptions were made:

- Biomass could replace 15% of the coal (in terms of energy) used in fluidised bed boilers and 10% of the coal used in pulverised coal-fired and grate-fired boilers; and
- Load factors were estimated on a nation-by-nation basis and for plants that use lignite and hard coal separately. This analysis was carried out using the Year 2004 annual national electricity generation by fuel dataset (Eurostat, 2006) and information from the CPPD on the national total electricity-generation capacity (with the exception of reserve capacity) for the two types of coal.

Case 1 and Case 2 yielded an unexploited technical potentials of 87 TWh/yr and 52 TWh/yr, respectively. This technical potential is small compared to the total electricity production in the EU-27 (around 3500 TWh). However, comparing this with the total production of electricity from solid biomass, which increased from 58 TWh to 80 TWh in the period 2008–2012, it is clear that co-firing has strong potential. Thus, on the European level, a two-fold increase in biomass-based electricity generation (compared with the current level) could be achieved through "moderate" co-firing alone. The largest technical potentials are in Germany, the UK, Poland, and Spain, corresponding to 65% of the technical potentials in Case 1 and Case 2.

During the period 2013–2014, a follow-up study based on the results of Hansson et al (2009) was performed by the same research team at Chalmers. Since the last study was conducted, the CPPD has been continuously updated. Currently, the CPPD contains information on coal-power plants that are co-firing biomass at the present time or that have been converted to use 100% biomass. In the follow-up study, this information was extracted from the CPPD, to estimate the potentials of solid biomass-based electricity production in co-firing schemes and full conversion schemes for Year 2012. The potentials were estimated using specific information in the CPPD regarding the maximum potential use of biomass for each plant. However, for some plants, while the CPPD states that co-firing is an option, the potential share of biomass is unknown. For these plants, the same assumptions were made regarding biomass shares[2] as in the previous study by Hansson et al., (2009). Furthermore, the same load factors as employed by Hansson et al. (2009) were used to estimate the potential for renewable electricity production.

Figure 21.3 shows the estimated capacities in Year 2012 of plants that had an actual co-firing option and for plants that were fully converted to use 100% biomass. In all, these power plants have a total net power capacity of 42 GW_e. Approximately 1% (0.4 GW_e) of this is for plants that had been fully converted for 100% biomass. The total net power capacity (42 GW_e) can be compared with the potential net power capacities derived in the previous study (Hansson et al., 2009), i.e., 166 GW_e and 90 GW_e for Year 2007 in Case 1 and Case 2, respectively.

Comparing the results for the different years shown in Figure 21.2 and Figure 21.3 reveal that the UK, Poland, and the Netherlands have used co-firing as an valuable strategy to increase solid biomass-based power production, since a large part of the potential in Year 2007 (as indicated in Figure 21.2) has been realised in Year 2012 (as shown in Figure 21.3) for these countries. For example, almost 67% of the estimated potential in Case 1 in Figure 21.2 has been reached in the UK. Furthermore, the figures reveal that there remains a large potential to further increase solid biomass-based power

[2] Biomass shares corresponding to 15% of coal (in terms of energy) in fluidised bed boilers and 10% of coal in pulverised coal-fired and grate-fired boilers.

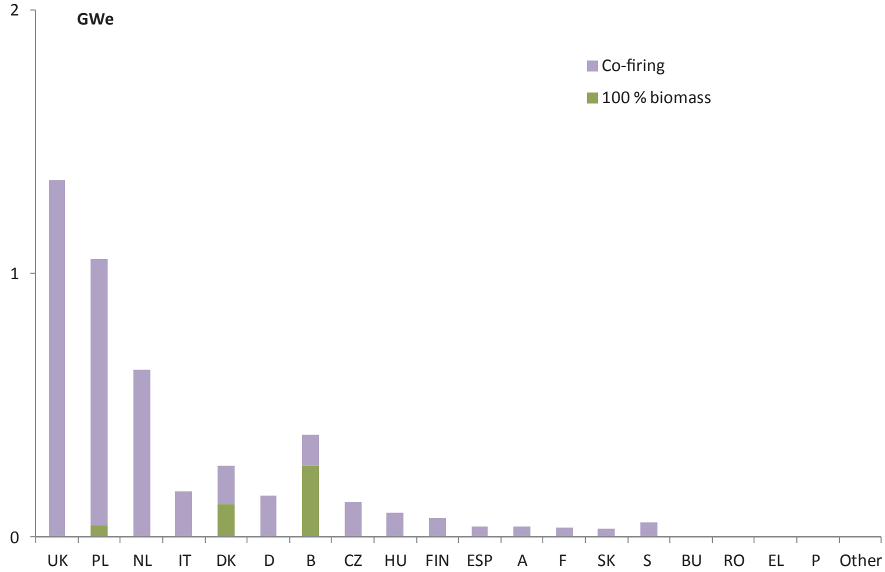

Figure 21.3. *Estimated actual biomass net power capacities in Year 2012 through co-firing (purple bars) and plants that had been fully converted to use 100 % biomass (green bars)*

production by co-firing and/or full conversion of coal-fired power plants in, for example, Germany, Spain, France, Romania, Greece, and Bulgaria, especially if more of the plants of age over 30 years is used.

These observations are confirmed in a comparison of the potential[3] for solid biomass-based electricity production in Year 2012 through co-fired/converted coal-fired power plants (according to CPPD) with the actual total production of electricity from solid biomass in Year 2012 (according to Eurobserver, 2013, see Figure 21.4. In the figure it is clear that co-fired/converted coal-fired power plants play an important role in generating solid biomass electricity in the UK, Poland, and the Netherlands. Looking at the three leading producers of solid biomass-based electricity (Germany, Finland and Sweden), and comparing blue bars in Figure 21.4, with Figure 21.2, it is mainly in Germany that co-fired/converted coal-fired power plants could play a substantial role in increasing production on a European level.

[3] The potential is calculated by assuming that all plants use their maximum possible share of biomass and have the same load factors as listed by Hansson et al. (2009).

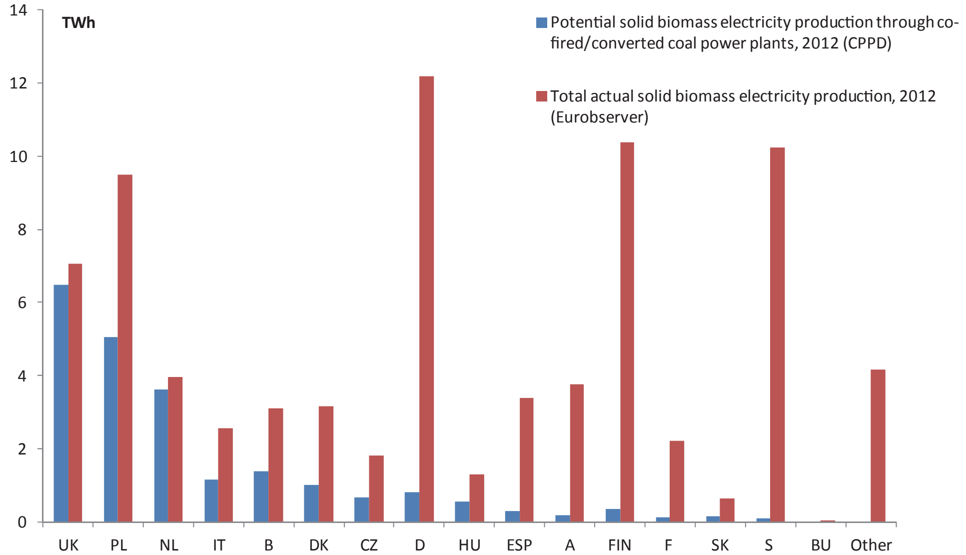

Figure 21.4. *Potential production levels of solid biomass-based electricity (gross) in Year 2012 from co-fired/converted coal-power plants (according to CPPD) and total actual production of solid biomass-based electricity (gross) in Year 2012 (according to Eurobserver, 2013).*

Economics of co-firing/full conversion

According to Dong (2012), using biomass in existing coal-power plants is more advantageous than using it in new dedicated biomass-fired power plants in terms of both higher conversion efficiency and lower capital costs. Referring to data of the IEA (2008), Dong (2012) estimates the investment needed to establish co-firing as being in the range of 120–1200 US$/kWe. As an example of what this means for production costs, these data are applied to a UK plant with the following characteristics:

- annual load factor: 4540 hours;
- co-firing share: 10%;
- economic lifetime of the investment: 15 years; and
- real interest rate: 6%.

This results in an increased production cost (excluding fuel costs) for electricity of 0.2–2.0 €/MWh[4]. This is in line with Strömberg (2013), who found that the biofuel feed system at a UK plant resulted in a cost increase (excluding fuel costs) of less than 1 €/MWh.

[4] At the exchange rate of 1 € = 1.35 US$

For comparison, Eurobserver (2013) has reported that the investment that was needed for full conversion to 100% biomass of three units (3 × 660 MW_e) at the DRAX plant in the UK is 845.5 M€, which corresponds to 580 US$/$kW_e$. Using the same assumptions as above regarding load factor, economic lifetime, and real interest, this translates into an additional production cost of 10 €/MWh (excluding fuel costs). This indicates that converting to 100% biomass yields higher specific costs than just converting to co-firing.

Besides this extra production cost, the profitability levels of co-firing and full conversion also depend on:

- the coal price;
- the biomass price;
- the CO_2 price; and
- the support system for renewable electricity production and the extent to which it includes co-fired/fully converted coal-power plants.

Thus, ensuring that co-firing is profitable would require a carbon price of 50–60 €/tCO_2 and the assumptions that: 1) any additional renewable support is excluded; 2) refined biomass costs 25–30 €/MWh; and 3) the co-firing investment cost is around 2 €/MWh. Regarding support systems, Dong (2012) pointed out that the European countries have adopted a broad range of mechanisms to support biomass co-firing. Some of these mechanisms, e.g., carbon tax and tax exemptions for biomass fuels, create disincentives for the use of fossil fuels by taxing them or by making GHG emissions expensive. Other measures aim to ensure viable markets for the electricity or heat produced from biomass, such as a feed-in tariff for renewable electricity or obliging electricity suppliers to include a certain level of renewable electricity in their supply portfolio. There are also policies and incentives that focus on investment support and cost reduction for biomass-based power generation projects.

Most governments appear to be increasingly in favour of feed-in tariffs, which pass on the cost of support directly to the end-users of electricity. Eurobserver (2013) reports that countries such as Germany and the UK are currently causing anxiety in investors by making market-type adjustments to their incentive systems. This development is backed by the European Commission, which in November 2013 advocated (in its new orientations for reforming renewable energy mechanisms) the phasing-out of feed-in tariffs and replacing them with other support instruments (e.g., tenders, the addition of purchase premiums to market prices, and quotas that oblige energy suppliers to purchase a certain amount of renewable energy), so as to encourage producers to adapt to market trends.

Development in the short-term perspective

The CPPD also contains data regarding planned capacity changes after Year 2012. These include plants that have been rebuilt for co-firing or fully converted to 100% biomass and that are coming online from Year 2013. Furthermore, planned capacity changes for Year

2014 and Year 2015 are included, as well as plans that have been announced but for which a definitive date has not yet been set for the changes that will take place. The latter category is designated as "After 2015 (including all plans)" in the figures below. The CPPD also includes information on plants that are being decommissioned after Year 2012.

Figure 21.5 shows the short-term development in the EU-27 for solid biomass-based electricity production through co-fired/converted coal-power plants if all the plans in the CPPD (including decommissioning plans) are realised according to the announced time schedule. The left panel of the figure shows net power capacity while the right panel shows the potential production of solid biomass-based electricity .

Regarding the development in Figure 21.5, the following observations can be made:

1) The majority of the plant changes will take place in countries that are already using co-firing as an important technology for solid biomass-based electricity production, such as the UK, Denmark, Belgium, the Netherlands, and Czech Republic.
2) The total net power capacity for co-fired/converted plants could increase by 5 GW_e.
3) The share of fully converted plants could grow from 1% (0.4 GW_e) in Year 2012 to almost 17% (7.9 GW_e) if all plans are realised.
4) The potential solid biomass-based electricity production (gross) by co-fired/converted coal-power plants could increase from 22 TWh in Year 2012 to 56 TWh if all plans in the CPPD are realised.
5) Fully converted plants could account for the majority of solid biomass-based electricity production in co-fired/converted coal-power plants, since the entire capacity is used for solid biomass at these plants, while only a fraction of the capacity (typically 10% – 20%) is used for biomass at co-fired plants.

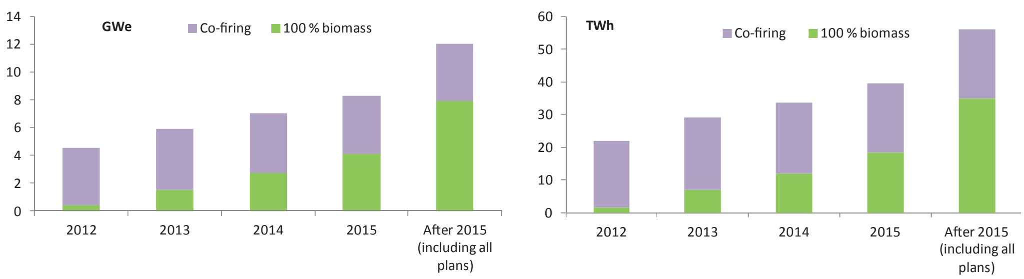

Figure 21.5. *Estimated developments in the EU-27 in terms of the actual biomass net power capacity (left panel) and potential production of solid biomass-based electricity (gross) (right panel) of coal-power plants that co-fire biomass (purple bars) or that have been fully converted to 100% biomass (green bars).*

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22 Mapping regional large-scale integration of wind power

The projection of a huge increase in the number of wind-power installations across Europe raises questions as to the availability of good wind sites and possible conflicts with alternative plans for land use. Even though the estimates are that the onshore wind-power potential in Europe is substantial, it is important to consider how wind power can be integrated optimally into the electricity system. In this chapter, we focus on a regional assessment of the potential of onshore wind power. The region in focus is the so called Kattegatt-Skagerrak (KASK) region, which includes western Sweden and southern Norway. Possible areas of conflict (i.e., areas where wind-power installations are considered as not being possible or feasible) that have been identified include densely populated areas, seas and lakes, roads, and areas of environmental, recreational and cultural importance. It is shown that these potential conflict areas collectively represent a relatively large fraction of the region, which limits the potential of wind power in the region. However, the remaining area is of considerable size. Moreover, a significant share of the available land area is associated with relatively good wind conditions, which means that the region could play an important part in expanding the share of wind power over the coming years. The methodology presented in this chapter is generic in nature and, thus, is applicable to other regions. Availability of data and geographical scope are two factors that determine the level of detail of the analysis. The method and the findings presented in this chapter are taken from a project that studies energy futures for the KASK region.

The Kattegatt-Skagerrak (KASK) region

The KASK region in focus in this study comprises two counties in Sweden and eight counties in Norway (see Figure 22.1)[1]. The overall aim of the entire study is to analyse pathways towards reducing GHG emissions, increasing energy efficiency, and increasing the penetration of renewables within the region. In this chapter, we give a brief overview of the activities that concern the mapping of wind-power resources in the region. This corresponds to the methodology reported in Chapter 8, in which the entire EU-27 block

[1] The KASK region includes parts of western Sweden, southern Norway and northern Denmark. In this study, however, we have omitted the Danish part of the region. The KASK region is one of several multinational regions included in the European INTERREG program. INTERREG IV is one of EU's so-called structural funds programs with focus on regional issues and the aim of strengthening cross-border regional cooperation (see info at http://www.interreg-oks.eu/se/Menu/Om+programmet/Interreg+programmen).

is considered in the analysis. This means that the level of detail is significantly lower than is practically possible to handle in a regional assessment such as the one reported in this chapter. This type of regional assessment is, of course, also applicable to other regions. In the same way as for the present KASK analysis, the availability of data and geographical scope determine the level of detail of the analysis, also for other regions.

Figure 22.1. *The KASK region analysed in this chapter consists of ten counties, with two of the counties situated in Sweden and the remaining eight in Norway.*

Conflict areas

To estimate the available land surface and, thereby, the potential for onshore wind power in the region, we identified a number of conflict areas. These are defined as areas where wind-power installations are considered as not being possible or feasible for different reasons. In total, more than 30 different conflict areas are analysed in the present analysis. These areas include lakes and seas, densely populated areas, roads, environmental and cultural protection areas, airports, and recreational areas (see Table 22.1). Buffer zones or safety distances, i.e., minimum distances to, for example, roads or densely populated areas, have been added to several conflict areas, thereby further reducing the available land surface.

While some of the conflict areas share the same category, the data by which they were assigned to that specific category originate from different sources. One such example is "roads", for which the data have been retrieved from both ESRI (2009) and the different County Administrative Boards involved in the Swedish part of the KASK region. As a result, some of the areas related to roads complement each other while others overlap. Overlapping areas may also be the result of merging conflict areas with different characteristics (e.g., some water areas may also be classified as Natura 2000 areas, thereby creating overlap). The overlap is, of course, handled appropriately in the analysis. However, since the conflict areas are reported as individual and "independent" areas in Table 22.1, the sum of the conflict areas may exceed 100% due to overlap.

For the Swedish part of the KASK region, 20 conflict areas have been evaluated, while the corresponding number for the Norwegian part is lower (10) due to lack of data (Table 22.1).

Quality check

It is important to point out that we have defined, *a priori*, the conflict areas as "no-go" areas for onshore wind-power installations. In some cases, this is obvious, while in other cases it may not be as obvious. For example, in the case of areas that are linked to tourism, one might argue that there could be room for wind power, at least to a limited extent. In particular, the conflict area termed "densely populated area" is highly uncertain. For what population density is it reasonable to assume that wind-power installations are unlikely? We know that we have to establish some limit, since conflicts with near-by inhabitants are common in cases of wind-power installations. In our analysis, we have investigated population densities of 10 persons/km^2 and 50 persons/km^2. This means that for population densities of more than 10 or more than 50 persons per km^2, respectively, wind power installations are assumed to be unfeasible. Following this definition, "10 persons/km^2" represents a larger conflict area than "50 persons/km^2".

Table 22.1. *Conflict areas used (marked with "X") for the respective counties in the KASK region analysed in this chapter (see Figure 22.1). The table shows the buffer distances that have been used, as well as the estimated width for data that originally were only represented as lines or as points.*

			Swedish KASK		Norwegian KASK								
Conflict Area	Buffer distance [meters]	Estimated width [meters]	Halland	Västra Göta-land	Akers-hus	Aust-Agder	Buske-rud	Oslo	Tele-mark	Vest-fold	Vest-Agder	Øst-fold	Ref.
Population 10, 30 or 50 per./sqkm	0		X	X	X	X	X	X	X	X	X	X	[1]
Railroads_ESRI	200	15	X	X	X	X	X	X	X	X	X	X	[2]
National parks	0			X									[3]
Natural reservations	0		X	X									[3]
Tourism and outdoor recreational activities	0		X	X									[3]
Unbroken coastline	100			X									[3]
Highly exploited coastline	100		X	X									[3]
Protected waterway	100		X	X									[3]
Airports	2 000			X									[3]
Outdoor recreation (activities)	0		X	X									[3]
Railroads	200	15		X									[3]
Railroads, planned	200			X									[3]
Cultural environment protection	0		X	X									[3]
Natura2000	0		X	X									[3]
Nature conservancy	0		X	X									[3]
Roads	200	Highway: 40 Other road: 10		X									[3]
Roads, planned	200			X									[3]
Restricted zone (Water source)	0			X									[3]
Watercourse	100		X	X	X	X	X	X	X	X	X	X	[2]
Roads_ESRI	200	Highway: 40 Other road: 10	X	X	X	X	X	X	X	X	X	X	[2]
Buffer area Grimeton	0		X										[3]
Animal and plant protected area	0		X										[3]
Cultural reserve_Halland	0		X										[3]
Natural monument area_Halland	200		X										[3]
Bog protection area_Halland	0		X										[3]
Landscape protection area_Halland	0		X										[3]
Buildings inventory area_Halland	200		X										[3]
Nature conservancy	0				X	X	X	X	X	X	X	X	[4]
Military exclusion zone	0				X	X	X		X	X	X	X	[5]
Reindeer farming / herding	Pasture land: 0 Path: 200	Path: 10					X						[5]
Nature conservancy, planned	0				X	X	X	X	X	X	X	X	[4]
Cultural heritage site	200				X	X	X	X	X	X	X	X	[5]
Cultural heritage site, surronding area	0				X	X	X	X	X	X	X	X	[5]
Cultural heritage building	200					X	X	X	X	X	X	X	[5]

[1] Eurostat (2013) [2] ESRI (2009) [3] Swedish County Administrative Boards (Länsstyrelserna) (2013) [4] Direktoratet for naturforvaltning (2012) [5] Norge digital (2013)

To check the validity of our conflict areas, we took a closer look at existing wind-power turbines and at planned wind-power turbines in the Swedish part of the KASK region. The aim was to identify the single turbines that were placed in our conflict areas. For a high number, one might suspect that our choice of conflict area is less appropriate or, in fact, that certain "conflicts" are inevitable when expanding the number of wind turbines in a given region. In the county of Västra Götaland, which is the largest of the two counties in the Swedish part of the KASK region, there are currently 471 turbines. The number of planned turbines in the same area is 1567. These numbers were valid in the Autumn of 2013. Thus, the numbers are sufficiently high to produce a fair quality check. In Figure 22.2, we present the share of all *existing* wind power turbines that are placed in a conflict area according to our definition. Each conflict area is denoted on the x-axis. Figure 22.3 shows the corresponding share of *planned* wind turbines. In general <10% of existing and planned turbines are placed, or are planned for placement, in a conflict area that accords with our definition. This gives us reason to believe that our choice of conflict areas is appropriate. However, the dataset may also be interpreted as exhibiting some "true conflicts", since our conflict areas are not entirely free of wind turbines. Furthermore, the numbers of the wind turbines placed in some conflict areas exceed the "threshold" of 10% of the total installed number. This applies especially when the population density of 10 persons/km^2 is chosen as a conflict area; in such a case, around 20% of the existing turbines are in conflict with other interests (in this case, urban areas). In contrast, choosing areas with a population density higher than 50 persons/km^2 as conflict areas yields very few "conflicts" (approximately 1%).Therefore, in the final analysis, we chose the intermediate density of 30 persons/km^2 as the limit for a densely populated area that is not suitable for wind-power installations.

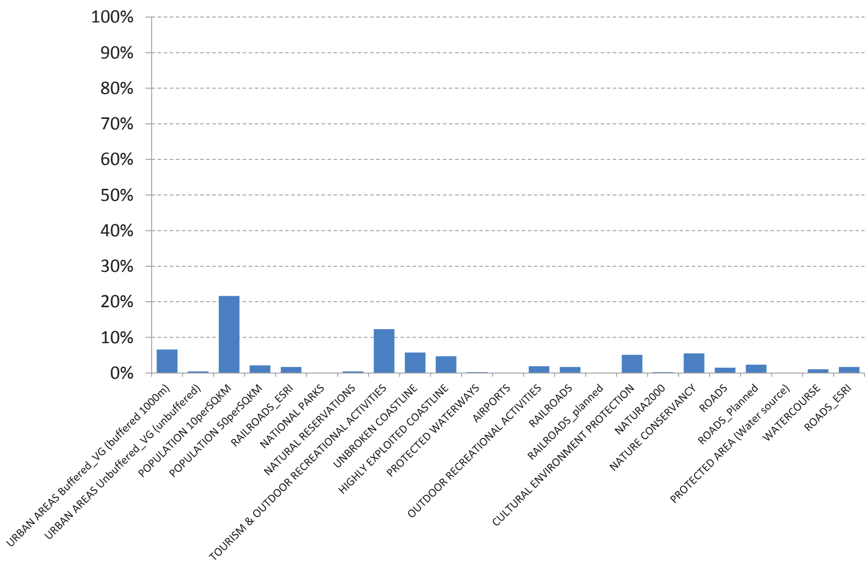

Figure 22.2. *The shares of number of total existing wind turbines in the county of Västra Götaland that are in conflict with the defined conflict areas.*

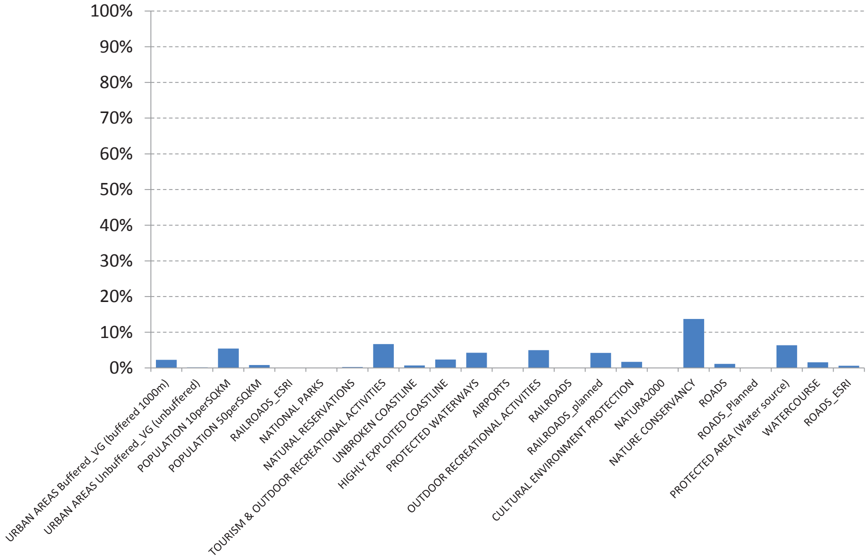

Figure 22.3. *The shares of the total number of planned wind turbines in the county of Västra Götaland that are in conflict with the defined conflict areas.*

Comparing Figures 22.2 and 22.3, it can be concluded that there are fewer conflicts for planned wind turbines than for existing turbines. This indicates that the process of choosing a site for wind power has improved or, at least, attained greater importance, at least if we consider our definition of conflict areas. Another part explantion could be that alternative land use has emerged some time *after* the installation of a wind turbine or a wind farm. Thus, existing turbines are ”in conflict” even though they originally were not.

The quality check described above was also performed for the Swedish county of Halland in the KASK region. Although there are fewer wind turbines in Halland than in Västra Götaland, the results for Halland follow a similar pattern, albeit with even fewer conflicts being identified.

Results

In Figure 22.4, the results of the GIS modelling (applying the conflict areas given in Table 22.2) are presented for the following assumptions regarding population density as a criterion for a conflict area: >10 persons/km^2 (left panel); and >50 persons/km^2 (right panel). It is evident that the available land surface area is significantly smaller in the former case.

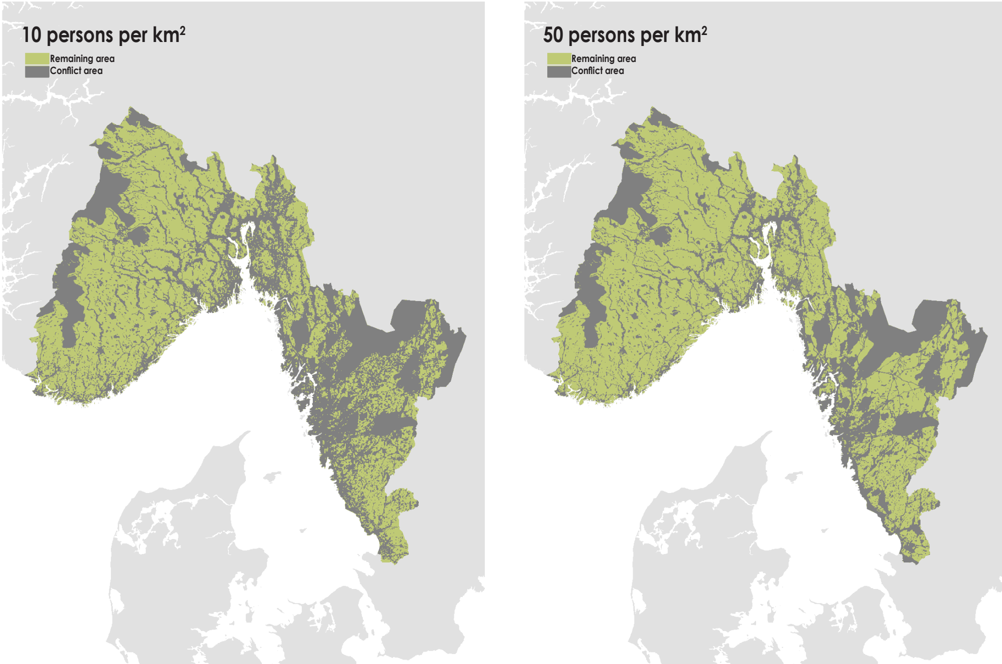

Figure 22.4. *Available land surface areas (in green) after subtraction of conflict areas according to Table 22.1 and for two assumptions regarding population density as a criterion for a conflict area: >10 persons/km^2 (left panel); and >50 persons/km^2 (right panel). In the final analyses we chose the density >30 persons/km^2 as the definition of conflicts with densely populated areas.*

The GIS modelling shows that approximately 60% of the original geographical area of the KASK region remains as potentially available after the surface reductions mentioned above. These results take into account the buffer zones surrounding the conflict areas, so as to reflect safety and publicly acceptable distances from wind-power installations, as discussed above. The results are reported in Table 22.2 (here we assume that our "final estimate" of >30 persons/km^2 as the conflict area defines conflicts with densely populated areas).

The Swedish part of the KASK region amounts to approximately 60% of the Norwegian part of the KASK region. Therefore, it is not surprising that the KASK region in Norway has a larger potentially available surface area than the Swedish region (see Table 22.2). Furthermore, more conflict areas have been deducted from the total land surface in the Swedish part than in the Norwegian part of the KASK region. Since the population density is higher in the Swedish part of the KASK region, assumed conflicts with densely populated areas are, accordingly, more numerous in that part of the region. It should also be noted that information on mountain areas/terrain/elevation has not been included as a conflict area or as a parameter that makes wind-power installations less feasible. Especially in the Norwegian part of the region, these considerations could have a significant impact. The same goes for proximity to the electricity grid, which also has been omitted from the analyses. Thus, even if our analysis indicates a large available surface area and strong potential for wind power in the Norwegian part of the region, the prospects for such installations are probably lower given all these considerations, which most likely would have significant impacts on costs.

Table 22.2. *Remaining land surface areas [km^2 and percentages] available for wind power after subtraction of potential conflict areas.*

	Original land surface [km^2]	Remaining land surface [km^2]	Remaining land surface [%]
Swedish KASK	34 313	14 626	43%
Hallands län	6 044	3 143	52%
Västra Götalands län	28 269	11 483	41%
Norwegian KASK	52 528	39 674	68%
TOTAL KASK	**92 841**	**54 299**	**58%**

Wind availability

The wind availability in the KASK region has been assessed using the same methodology and dataset as reported in Chapter 8 for the EU-27 study (at a hub height of around 100 metres). Wind availability may be expressed in terms of capacity factor (%), which is the ratio of full-load hours of a wind-power installation to the total hours in 1 year. Full-load hours, in turn, are given as the ratio of electricity produced during 1 year to the rated power. In Figure 22.5, the estimated capacity factors of the KASK region are shown according to the wind-availability grid-cell structure presented in Chapter 8. In the same figure, we also present the available land surface, after deduction of the defined conflict areas, for each of the grid cells, expressed as percentages of the total original land surface.

Estimation of the potential for wind power and a simple profitability analysis

Combining wind availability and available land surface area for wind-power installations in each grid cell (cf. Figure 22.5) reveals the extent of possible and profitable wind-power investments in the region. In Figure 22.6, the full-load hours for each grid cell are arranged in decreasing order. The corresponding available land surface (after subtraction of the assumed conflict areas) is indicated on the x-axis of the figure. According to the figure, the available potential is greater in Norway. As mentioned above, this is likely to be an overestimation in relation to the Swedish part of the region. If the numbers of full-load hours are known, it is possible to do a simple profitability check. Total costs of wind power are determined by full-load hours and assumptions regarding investment costs and operation and maintenance (O&M) costs. Based on default assumptions, a wind-power installation with 2500 full-load hours per annum typically costs around 55 €/MWh. We assume only moderate grid-integration costs. If the number of full-load hours is decreased to 1500 hours, i.e., by choosing a significantly less appropriate site, the total generation costs increase to around 100 €/MWh. Three such estimated production costs are included in Figure 22.6 and placed adjacent to the corresponding full-load hours.

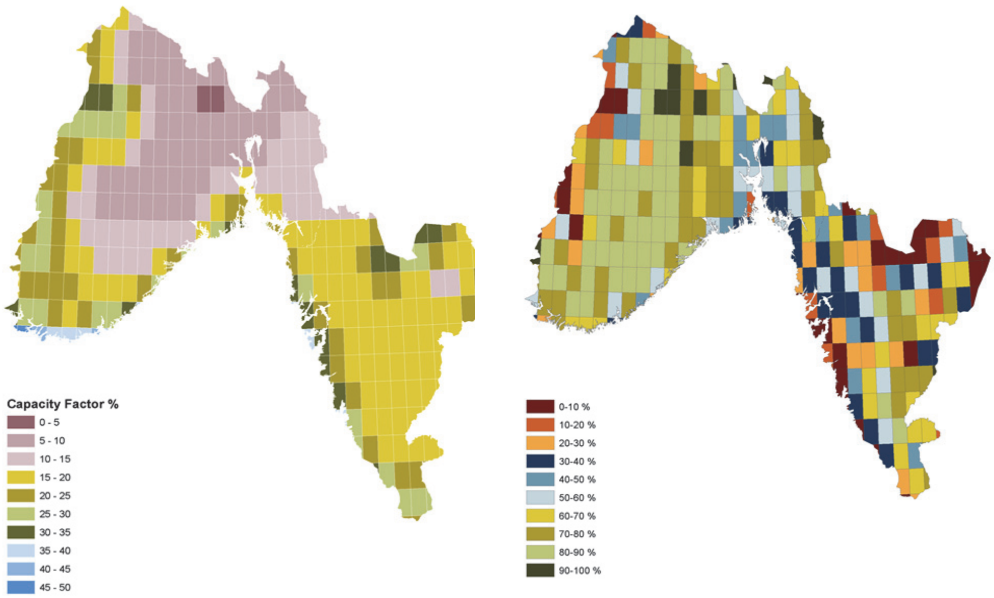

Figure 22.5. *Left panel: Capacity factors for the respective grid cells in the Swedish and Norwegian parts of the KASK region. Right panel: Percentages of original grid cell land-based areas in the Swedish and Norwegian parts of the KASK region that remain after subtraction of the areas in conflict with wind power. The grid-cell representation accounts for land areas within the KASK region. Grid cells situated in either coastal areas or that border land areas outside the KASK region have been adjusted so that the grid cell only accounts for a land surface area within the KASK region (this value represents 100% of the original grid cell).*

Modelling the development of the Nordic electricity market gives projected wholesale electricity prices of typically 40–45 €/MWh for the coming years. The prices of electricity certificates in the common Swedish-Norwegian electricity certificate market, which is a support scheme for renewable electricity in the two countries, have in recent years been around 20 €/MWh. If that price level prevails, which seems likely, the total income for new wind-power investments may reach 60–65 €/MWh. Based on the information shown in Figure 22.6, around 3000 km^2 in the Norwegian part and around 1000 km^2 in the Swedish part of the KASK region would in that case be profitable. This is less than 10% of the entire land surface estimated as being available for onshore wind power. However, if we assume that this surface is available for entire wind farms, then the installed capacity could reach an impressive 40 GW (4000 km^2 × 10 MW/km^2).

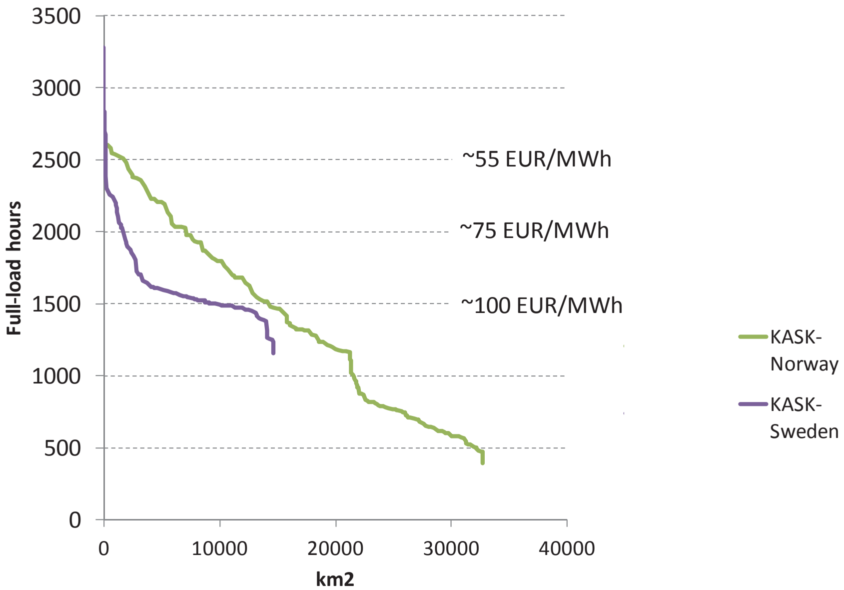

Figure 22.6. *Full-load hours for onshore wind power in the Swedish and Norwegian parts of the KASK region, arranged in decreasing order. The figure includes estimates of the levelised costs of electricity for wind power for three different full-load hours (assuming investment cost of 1330 €/kW, O&M cost of 25 €/kW, and a real discount rate of 7%).*

Final remarks

Comparing this regional analysis with the all-European approach presented in Chapter 8 allows us to draw some conclusions regarding the relevance of more-detailed regional assessments when estimating the potentials and options for large-scale wind integration. In the all-European study, it was concluded that roughly 70% of the land surface is available for wind-power installations. Looking at the KASK region in the all-European study, almost 70% of the land area of the KASK region is estimated as being available for wind-power installations. This can be compared to the estimation in the present regional analysis where less than 60% of the land surface area is considered to be available for wind-power installations. Thus, broadening the concept of likely "no-go" areas reduces the available land surface. Furthermore, for the Swedish part of the KASK region, which has significantly more "no-go" areas than the Norwegian part, less than 45% of the land surface is estimated to be available for wind-power installations. Therefore, there is a compromise between the geographical boundary and the level of detail that can be achieved. As mentioned in

Chapter 8, apart from the estimation of available land surface, the assumed power density of wind-power installations is a crucial parameter. Since the European study has a lower level of detail regarding the number of likely or possible "no-go" areas, due to the amount of available data, a relatively low assumed power density may be feasible to reflect broadly the exclusion of possible "no-go" areas. On the other hand, in a regional study such as the present one, the higher number of conflict areas may motivate the choice of a significantly higher power density.

Swedish communities are obliged, by law, to present energy plans that cover the geographical boundaries of their communities. However, as there are no major requirements as to the actual contents of such plans, they may be regarded as relatively flexible in terms of scope and detail. Nevertheless, a broad assessment and environmental aspects should be included. In parallel with these energy plans, many Swedish communities have presented specific wind-power plans. These give valuable insights into the ways that different communities value the role of wind power and to extents to which they estimate available land surfaces for such installations. When looking into these plans for the six communities of Halland County, one of the two Swedish counties included in the KASK region, we conclude that they, generally, have a more limited view of the availability of land surface than we have estimated in our analysis. The factors that they include are more politically or strategically motivated, reflecting the different ambitions of the communities. One such example is how the communities in some cases include significantly larger buffer zones around densely populated areas, with the justification that they expect (or hope) that their cities will grow and they want to reduce the possibility of future conflicts over wind-power installations. Furthermore, these communities tend to be more restrictive in terms of wind-power installations if they consider that these could be in conflict with tourism objectives. Thus, competing land use tends to be assigned a higher value in these plans than what we have estimated here. However, one might argue that areas that are currently considered as unlikely sites for wind power installations may be selected as sites in the future. This further underlines the difficulties associated with estimating available land use and potentials for on-land wind power. In reality, each wind-power installation is treated as a unique project with unique conditions. Nevertheless, estimations of the potentials of wind power are necessary when assessing strategies and options to increase the penetration of renewables. When doing so, we must be aware of the fact that wind power is not uncontroversial and that on-land wind-power installations in many cases have to compete with alternative forms of land use.

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23 Perspectives on capacity markets

The continuous growth across Europe of renewable electricity with low running costs has led to reduced utilisation of existing thermal power plants. However, these plants are essential in providing sufficient backup during periods of low availability of wind and solar power and in ensuring grid stability and frequency control. To encourage operators to keep these plants available rather than taking them out of operation if they are deemed to be stranded assets, there is growing interest in capacity markets as a complement to the European target model, i.e., the energy-only market. However, introducing capacity markets will affect the conditions of current power markets. If such markets are introduced in certain countries and not in others, cross-border trade may become unbalanced.

Introduction

To date, the electricity markets in the Nordic countries and the EU have been characterised by trade in energy on an hourly basis or shorter intervals, the so-called Energy-Only Markets (EOMs). In an EOM, the actors are paid only for the delivery of electricity, and are not compensated for available capacity. For investments in an EOM to become profitable, energy shortages must occur or there must be a high risk of such occurrences during a certain period each year. The introduction of substantial levels of intermittent power generation, such as wind and solar power, which are highly variable over weeks, days, and hours, represents an additional challenge for investments in thermal power plants. Increasing the share of variable renewable electricity may require a degree of adjustability for hydropower (which is important in the Nordic countries) and for thermal power (which is important in the rest of Europe), which complicates the investment issue. Since the current expansion of renewable electricity is massive, and economic growth is relatively slow, there will be no need in the coming years for new base-load power generation. However, the demand for adjustable capacity may rise during hours with high consumption and little generation of wind and solar power in continental Europe. These types of investment, which involve gas turbines with short duration of operation and demand flexibility, are dependent upon the presence of high prices on these occasions, are probably the most risky instruments in the power market. Therefore, actors who provide this type of capacity will have the highest demands for return on investments, assuming that they are willing to make these investments at all. If investments in gas turbines and demand flexibility are insufficient, periods of deficiency may become more frequent, which would incur high costs for the countries concerned. The cost of under-capacity is much higher than the cost of the over-capacity, especially since the risk of shortages increases significantly as the under-capacity grows larger. This is why different forms of re-regulation of the European electricity markets are currently being discussed. One alternative is to establish a capacity market (CM) that covers either all of the EU or just specific countries. In a CM, the required capacity can be purchased, possibly being subdivided into different categories of energy and demand flexibility. In practice, sufficient capacity should be purchased or reserved to make the risk of shortages negligible.

Several Member States have already introduced or are on the cusp of introducing CM mechanisms into their electricity markets (Figure 23.1). Thus, CMs or CM mechanisms are already a fact, and the question now is what this development will mean for the prospects of the single European electricity market.

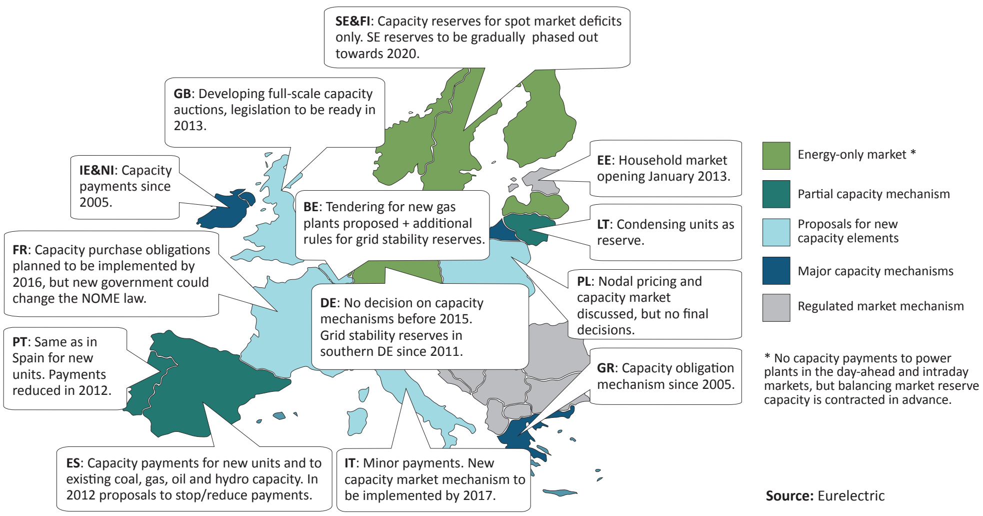

Figure 23.1. *Overview of existing and planned electricity market designs in EU.*

Fundamentals of capacity markets

In a CM, a specific level of capacity can be guaranteed. Both society and the different actors are thereby relieved of the risk associated with an EOM, in which available capacity is at risk of being reduced to an undesirable level. Since the costs for under-capacity are much higher than those for over-capacity, a CM that is efficient from a socio-economic viewpoint should be designed with a certain degree of over-capacity. In a CM, it is not the actors who decide the size of investments, as is the case in an EOM. Instead, the investments are determined by the capacity purchased on the CM. Politicians make the final decisions about such investment levels. The foundations of a socio-economically efficient CM should be based on socio-economic rates of returns on new investments, rather than on market-based rates of returns, as applied in an EOM.

Compared with an EOM, the risks are reduced in the following ways for different actors in a CM:

- Society secures the desired capacity through procurements;
- The ground is laid for more socioeconomically efficient investments;
- Actors investing in new capacity, regardless of whether this in different types of power plants or in demand flexibility, have a stronger assurance of a return on their investment. This lowered risk will, through reduced yield requirements, reduce the capital costs for these actors; and
- For electricity consumers, price fluctuations will be fewer, with relatively stable capacity prices, which means that price spikes will be less common if not eliminated.

CM is a tool for maintaining a certain level of capacity, which is more difficult to achieve in an EOM. In an EOM, investments are dependent upon the actors' perspectives of the future, e.g., the levels of profit that they demand. These demands do not necessarily reflect the profit demands considered reasonable by society.

Optimal investments in a thermal power system

The hours that have the weakest capacity balance (i.e., high consumption and little non-dispatchable electricity generation, possibly in combination with problems associated with base-load power plants and transmission capacities) promote price movements that are determined by costly demand flexibility or scarcity-cost pricing (since an administrative price ceiling exists on the spot market when the balance between demand and supply is not achieved). The higher the utilisation time of a power plant or a demand measure, the more hours are available for allocating fixed costs. Thus, it is profitable to replace demand flexibility that has high variable costs but low fixed costs with demand flexibility that is associated with low variable costs but higher fixed costs. Above a certain utilisation time, it becomes more profitable to replace demand flexibility with gas turbines that have lower running costs and higher fixed costs. Typically, after about 1 000 hours of utilisation time, it may be more lucrative to replace gas turbines with combined cycle gas turbines (CCGT), which have lower running costs but higher fixed costs. In the same way, after several thousand hours of utilisation time, coal-fired condenser power becomes more profitable than CCGT. If it is feasible to build nuclear power plants or plants that are based on the combustion of lignite, this might be profitable compared to coal-fired condenser power, despite the fact that these types of power plants have the highest fixed costs. However, these plants have to be in operation almost year-round. In this way, it is possible to calculate and design an optimally dimensioned thermal power system (by estimating the utilisation time that gives the same overall economic outcome) from investments that have the highest variable costs to those with the lowest variable costs. The technologies mentioned above are merely examples. For example, with increasing prices of CO_2, CCGT could end up with lower variable costs than coal-fired condenser power. An increased share of wind and solar power could also lead to plants (e.g., coal-fired condensing power) being in operation for too few hours to be profitable, while CCGT could still be lucrative for the remaining time.

Risks and rates of return

The demand for return on investment has least significance for investments with low fixed (capital) costs and vice versa. The most important factor in determining demands for profit is the risk that the project carries. Risk is ultimately calculated as the difference between the estimated revenue and the costs. The risks can be many, can differ between various types of investments, and can be associated with varying possibilities for mitigation. It is not easy to grasp the full picture of risk even in theory, and it is of course much more difficult to handle the risks in reality. In reality, a decision may have to be based primarily on a strong belief regarding the future.

Our conclusion is that investments that rely on the occurrence of electricity price peaks with sufficient frequency and magnitude will require higher returns than investments in base-load plants because the risks are higher.

Design issues related to capacity markets

When designing and establishing a CM several issues must be addressed. We highlight a few of the more significant issues here.

Adequate contract duration for the actors in a CM

A crucial issue is how long the contracts with the actors in the CM should be. Stoft (2002) advocates contract duration of at least 1 year. This would embrace the power balance over all phases of a year, including seasonal variations in, for example, consumption, wind power, and solar power. Since an important purpose of a CM is to reduce the risks perceived by the actors in an EOM, the contracts should not be of too short duration. Therefore, a 1-year contract may be too short and may lead to high yield demands from the actors in the CM. They will have to calculate the return on their investment bearing in mind the risk that their capacity will not pay off in a year. Longer-duration contracts might be offered for investments with short utilisation times, such as gas turbines and demand flexibility. Conversely, investments in instruments that have longer utilisation times and that receive a large part of their revenues from the EOM could accept shorter contracts.

In a situation of capacity surplus, the prices on a CM will drop, perhaps to a level where the revenue only covers the cost of having a power plant that is ready to start, as an alternative to having it mothballed. When over-establishment occurs, Stoft (2002) has argued that it can be corrected quickly in a CM, assuming that consumption increases. With stagnating electricity consumption in the Nordic countries and Northern Europe and with the introduction of significant levels of wind and solar power under non-market conditions, over-capacity may persist for a long time. Under these circumstances, no investments will be made for longer periods, and investors may have to live with the over-investment for a long time.

Demands for return on investments determine capacity prices

One consideration is whether the prices on a CM should be determined by the demands for return on investments made by society or by the actors (utilities and consumers) in the CM. In general, societal rates of return are lower than private or corporate rates of return. If capacity prices are determined by the actors' rates of return on investments, these prices are likely to be higher than if capacity prices are affected by the societal rate of return. Thus, the societal impact is a lower demand for power than if the societal rate of return determines the price. However, this effect will be small at the outset, and will become even smaller, since the actors' demands for return on investments will be lower in a CM than in an EOM. For the supply side, there is no alternative; the actors' profitability requirements must be applied. The lower societal profit demand would, in such a case, not stimulate a sufficiently large supply.

Lowest bid or splitting into different categories of power and demand flexibility

We have argued that the investments made in a CM should be based on either socio-economic yield requirements or on a societal discount rate. However, the capacity bids made in the CM will be determined by the actors´ own profit requirements, which in turn are dependent upon the lengths of the contracts offered. The most straightforward approach would be for the CM to tender for lowest bids (in €/kW) distributed over the period of the contract. Investments with low variable costs would get the largest proportion of the investment cost covered by the EOM, and would need only a minor contribution from the CM. However, gas turbines and demand flexibility would need to have the major part or entirety of the investment covered by the CM. With this approach, the composition of the capacity traded on the CM would be largely unpredictable, in that it would depend heavily on the yield requirements set by the actors themselves, which could be significantly different from realistic societal yield requirements.

Penalties imposed when actors in the CM fail to deliver

While the actors in a CM must maintain the contracted capacity, they are also obliged to deliver power generation or demand reductions when directed to so. Otherwise, there is little justification for the CM. Stoft (2002) has argued that penalties should be imposed if an actor is not activating the capacity directed by the CM at a given moment. The view of Stoft (2002) is that the penalty imposed must be higher than the cost of new capacity in the form of new gas turbines.

Should demand flexibility be given special treatment?

Activities related to demand flexibility are associated with actors such as electricity-intensive industries and real estate companies, i.e. actors other than those having the electricity market as their main arena. Moreover, actions within demand flexibility are more dependent upon the frequency and amplitude of price peaks in an EOM, or in the case of a CM, situations with risk for capacity deficit. If a CM can eliminate these risks, its main benefits would be materialised. With high levels of demand flexibility, price peaks would be seen also on a CM, even if a capacity deficit never occurs. The market can be established with short-term price signals, as well as with safe investments. The prices on a CM can be maintained below the fixed costs for gas turbines if the demand flexibility engaged is sufficiently large. However, these actors are not familiar with electricity market issues, and they have difficulties with demand flexibility for which they lack experience in a market perspective. They are used to producing manufactured goods, as cheaply and as reliably as possible, and to always delivering to customer expectations, at an agreed point in time. The bids from the industrial companies on capacity reductions will therefore be limited in terms of capacity, number of hours, and repeatability, since the companies will be reluctant to promise too much in advance, taking their customer commitments into account. It might be beneficial for these companies to go for shorter contract periods on the CM, which would give them a clearer view of their sales status. Obviously, it will be a challenge for the buyers on a CM to value these limitations in the utilisation flexibility bids in comparison to the bids from conventional power generation. This could be a reason for a CM to give utilisation flexibility special preference over bids from power companies.

Early results from the modelling

The research presented in this book has been conducted in close co-operation with another ongoing research project, namely the NEPP project (www.nepp.se). In that project, the focus is on the design of electricity markets and on issues related to the North European electricity system. This also includes model analyses of the CM and EOM. Preliminary findings related to the introduction of CM and that are based on a European-wide modelling performed by Sweco suggest that:

1. A CM will involve, in several cases, substantial increases in supply capacity, as compared with an EOM.
2. The introduction of a CM will reduce the profitability levels of interconnectors. A special case is if a CM is introduced at only one end, i.e., a country or region, of a given interconnector.
3. A CM is likely to reduce wholesale electricity prices, as compared with an EOM. This reduction is especially pronounced during peak-load segments. Thus, the model runs indicate that this impact is greater in continental Europe than in the Nordic countries due to the generally larger differences between peak-load and low-load prices in continental Europe.
4. In continental Europe, retail prices for electricity will be relatively unaffected by the introduction of a CM, since the reduction in wholesale electricity price is compensated for by the price of capacity. In the Nordic countries, however, the model results indicate that retail prices may increase, since the reduction in wholesale electricity prices are very marginal and do not sufficiently compensate for the added capacity price.

In this chapter, we have argued that CMs may play an important role in restructuring electricity markets by e.g. supplementing EOMs. There are indeed some features of a CM that are appealing, especially in an electricity market that is characterised by a large share of variable renewable electricity generation. However, CMs are not without disadvantages and risks. Some of the experiences that have been gathered in different parts of the world do not exclusively paint a bright picture as regards CMs. For instance, it is argued that the difficulties in projecting the needed capacity has led to significant overcapacity and, thus, unnecessary high consumer costs in the Western Australian power market that, among others, includes a CM (Nelder, 2013).

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The demand-side perspective

Demand-side issues associated with the residential and commercial sectors are in focus of this main section. In this context, demand-side management (DSM) is a central concept. DSM includes a large variety of activities, such as conservation, efficiency measures, and load shifting. Increasing consumer awareness and the prospects for facilitating the integration of renewable electricity generation is likely to lead to a tighter linkage between demand and supply. Therefore, increased demand flexibility will play a key role in the transformation to a more sustainable electricity system. A final example in this section deals with electric vehicles and the possible linkages to variable electricity generation.

24 Perspectives on demand response

Traditional energy systems have been designed so that the production side responds to a change on the demand side. The concept of demand response (DR) challenges this notion, and introduces the idea that the demand side can, to a certain extent, react to changes on the production side. Until now, the need for demand response has been limited, since production has mainly been composed of flexible and base-load plants and it has been cheaper and more convenient to regulate production rather than demand. However, as the level of intermittent electricity production (primarily in the form of wind and solar power) increases, the benefits of being able to control the demand become apparent.

In this book, we show that increased shares of variable generation of renewable electricity present new challenges to the electricity infrastructure. In addition to issues related to the operation of conventional thermal power plants, congestion and system stability, e.g., frequency control, also need to be addressed, to facilitate successful and efficient large-scale integration of renewable electricity. In Figure 24.1, the issues that can be addressed are encircled; demand response could help to alleviate problems both on short timescales (milliseconds to minutes; red circle) and medium timescales (hours to days; green circle).

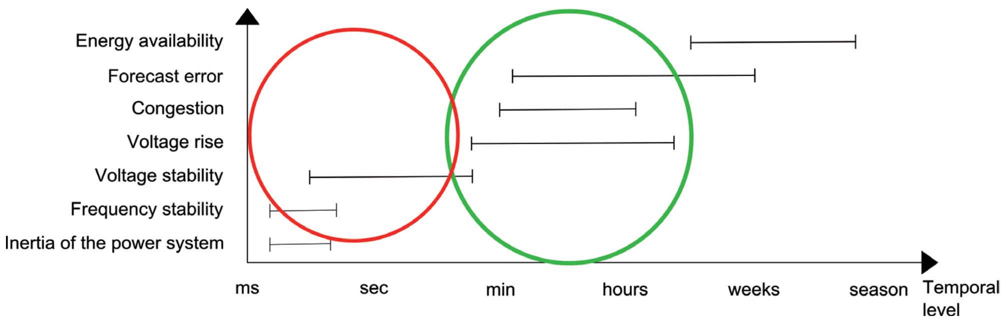

Figure 24.1. *Grid-related challenges in which demand response could offer possible solutions.*

What is demand response?

Electricity demand is to a large degree uncontrollable from an electricity producers point of view, it varies with time of day and season, and consists of a high number of individual loads, ranging from home appliances to industrial equipment. Usually, these loads and any changes in them are met by increasing or decreasing electricity generation. However, within the wide range of loads, there are ones that could be easier to shift in time. Demand response makes use of these loads by dispatching or reducing them at appropriate times. This dispatch occurs through the implementation of incentives or restrictions for the electricity consumer, who is in control of the load. Thus, demand response is a change that is made in the consumption pattern of an electricity consumer and that is instigated by some driving force. This change can entail load curtailment, i.e. reduction of the load, or shifting the load in time. Thus, demand response can result in both a reduction of demand and a shift of demand in time. However, this reduction should not be equated with efficiency improvements, as it is due to removal of load rather than improvement of load efficiency. In this context, demand-side management (DSM) may be viewed as a broader concept than demand response. The concept of DSM includes a demand response, as defined here, as well as end-use efficiency and conservation measures.

Traditionally, demand response has meant that the demand should be "flattened" to the greatest extent possible, as the smoothing of variations in demand reduce the need for reinforcements of weak grids, reduce losses, and reduce the use of expensive peak-power plants, i.e., generation units with high running costs. However, as more intermittent production is introduced, the goal is no longer to flatten the demand but instead to make the demand follow the intermittent patterns derived from the renewable production. In Figure 24.2, the different strategies are illustrated, with the left panel showing demand response in a traditional electricity system and the right panel presenting demand response in a system with distributed intermittent generation. In the case of distributed intermittent electricity production, it is clear that a shift in demand could lead to increases in peak demand, as compared with the traditional case in which the goal is always a reduction in peak demand. It should be noted that for distributed intermittent generation, the increased peak demand may not affect the regional or national grid because the electricity is produced locally, whereas for systems with large centralised intermittent generation, e.g., large offshore wind-power parks, the possible load shift may be limited by the transmission capacity of the power system.

Demand responses in different demand sectors

As mentioned above, demand response exploits the controllable loads in the demand sector. As these loads are available on the demand side in all sectors, i.e., domestic, commercial and industrial, demand response can be implemented in all of these sectors. However, the sizes of the loads, as well as how far ahead in time they can be shifted vary between the different sectors.

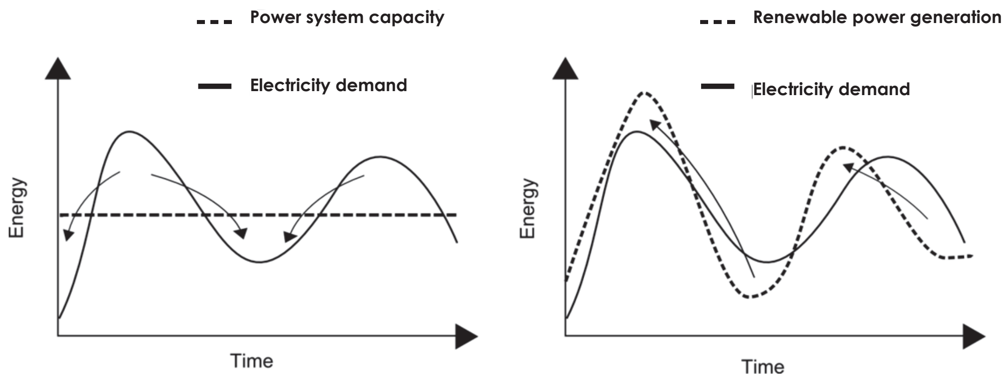

Figure 24.2. *Comparison of demand response strategies in a traditional electricity system (left panel) and in a system with a considerable level of intermittent generation (right panel).*

For the domestic sector, demand response may mean the shifting of loads for services that are not immediately required, e.g., starting the dishwasher an hour later. Other examples of services for which the loads can be shifted are washing machines and dryers. While such loads (and the energy they use) can usually be shifted quite far ahead in time (hours), they cannot usually be stopped once they have been started. There is also the possibility of using loads that can be shifted for short periods of time (minutes) and that can be started and stopped without major repercussions, e.g., freezers and refrigerators. These loads are considered to be useful primarily for frequency control, due to the short time period for which the demand can be shifted. Electric space heating, water heating, and air conditioning could also be used through the storing of hot water or allowing the indoor temperature to vary within a given temperature range. The sizes of space heating/cooling loads and the time-frame within which they can be shifted are dependent upon building materials/insulation and weather conditions and are, thus, not easy to quantify. All of these measures cause little or no inconvenience for the end-user, as the service of the appliance is still provided. However, there are limits as to how far into the future these loads can be shifted. These limits are set by the preferences of consumers, i.e., the acceptable temperature range and the acceptable time that a load can be postponed. There is also the possibility for the consumer to avoid using a load altogether, although this implies that the service is not provided, thereby possibly reducing the comfort of the user. The sizes of the demand response loads for an average Swedish household are listed in Table 24.1. It is evident that the largest potential in Swedish houses lies in shifting the heating demand. In contrast, for regions in more southern latitudes, air conditioning represents the major load.

Table 24.1. Important characteristics and corresponding average values for different demand response loads in Swedish households with a distinction between single family dwellings (SFD) and multi-family dwellings (MFD) *(Zimmerman, 2009; Timpe, 2009)*.

Load	Household type	Load size (Energy demand)		Cycle time	Displacement time	Prevalence
		(kWh/ year)	(kWh/ cycle)	(hours)	(hours)	(appliance per household)
Space heating[1]	SFD	6800-20000	n.a	n.a	n.a	n.a
	MFD	n.a				
Water heating[1]	SFD	1500-3000	n.a	n.a	n.a[2]	n.a
	MFD	n.a				
Fridge[3]	SFD	200-230	n.a	n.a	0-1	0.62
	MFD	140-260				0.32
Fridge-Freezer[3]	SFD	410-530	n.a	n.a	0-1	0.38
	MFD	450-500				0.58
Freezer[3]	SFD	370-590	n.a	n.a	0-1	0.88
	MFD	330-440				0.45
Dishwasher	SFD	140-240	0.2-1	2	0-24	0.9
	MFD	70-210				0.51
Washing machine	SFD	110-210	0.3-1.2	1-2	0-24	1.01
	MFD	60-170				0.52
Dryer	SFD	100-130	0.4-2	1	0-24	0.59
	MFD	240-320				0.15

[1] Includes only direct electric heating.
[2] No values are given for space and water heating loads as these values highly depend on the storage capacity and the acceptance range for temperature fluctuations.
[3] Fridges and freezers do generally not work in specific cycles as e.g. washing maschines. Thus, cycle times are given as "n.a." in the table. A realistic estimate of the displacement time depends on the upper limit for postponing the load of a fridge or freezer without jeopardizing food quality. This estimate is taken from the literature.

In the commercial sector, which includes public buildings, as well as offices and shopping malls, shiftable loads are similar in character to those identified in the domestic sector. However, the possibility to shift appliance loads is limited, since most of these are used continuously, e.g., computers. Similar to the domestic sector, air conditioning and heating loads have the largest potential for shifting. In addition, ventilation or regulating the intensity of lighting could be used for load shifting.

For the industrial sector, demand response could mean shedding loads, i.e., stopping production or using dual-fuel systems, in which other fuels could temporarily replace electricity, or rescheduling the loads. However, industrial demand response is already in use to some extent, particularly in those industries that take part in the electricity reserve/balancing/frequency markets. Thus, industries commit to shutting down loads when the demand on the power system becomes too onerous. Nevertheless, there may be possibilities for industries to reduce their costs further through a more active demand response.

There are limits as to how the industrial demand response can operate. Stopping production is associated with a loss in income, so savings from avoided electricity use have to be equal or greater than the loss of income. This means that electricity-intensive industries, i.e., industries in which electricity is a major part of the production cost, are more likely to engage in demand response. Rescheduling loads requires that the load in question is flexible. Loads that operate at maximum capacity, i.e., that are operated continuously, do not allow the possibility to shift the load as there is no time-point to which the load can be deferred. Similarly, loads that are constrained to certain hours cannot be shifted. In such cases, load shedding is the only possibility.

The need for regulating power

It is likely that the need to regulate power will increase with increased levels of intermittent renewable generation, given the intermittency of this type of generation and the inevitable competition with conventional power plants. The latter implies that the traditional, flexible power plants may be decommissioned owing to reduced utilisation, thereby further increasing the need for regulating power.

In the Nordic electricity market, the demand side can participate in both the regulating market, e.g., to maintain the balance/frequency within the system, and in the peak-load reserve, which is a reserve that is used to meet critically high demand. Currently, most of the reserve is provided by the generation side, although the Swedish transmission system operator (TSO) is aiming to increase the contribution of the consumption side (Svenska kraftnät, 2011).

Although it is possible for customers to participate in regulating the power system, the requirements regarding response time and regulating capacity are stringent and the participating customer must either have a high level of demand, e.g., industries or large commercial buildings, or be aggregated together with other customers. With evolving business models and increased incentives, demand-side participation may play an important role in the future regulating market.

Real-time pricing and variable electricity generation

In a power market, the price of electricity depends on the demand and the available generation. When there is a surplus of generation and/or low demand electricity prices are generally low, while the opposite holds when there is a shortage of generation and/or high demand. For power systems that have a large share of intermittent generation, situations of surplus or deficit will likely be more common, leading to more volatile electricity price development. The underlying principle of real-time pricing (RTP) is to allow customers to react to these price fluctuations by reducing/increasing their flexible demand. This would both increase the reliability of the power system and help to integrate intermittent renewable energy sources by reducing demand during on-peak hours and increasing demand during off-peak hours or during hours with excess renewable production of electricity. As an example, take 2 hours with the same amount of load and during one of these hours there are large amounts of intermittent renewable electricity generation, while in the other hour there is not: as the generation cost of intermittent renewable electricity is almost zero, the supply curves would look different for the two cases (Figure 24.3), resulting in a lower marginal electricity price for the high intermittent renewable generation case. If the load could be moved from the hour with low intermittent renewable generation to the hour with high intermittent renewable generation the total cost of the electricity for the two hours could be reduced. This is illustrated in Figure 24.3, where the area marked in red represents the decrease in system cost for the low intermittent renewable generation hour, and the area marked in blue represents the increase in cost for the hour of high intermittent renewable generation. The red area is larger than the blue, reflecting a net reduction in system cost.

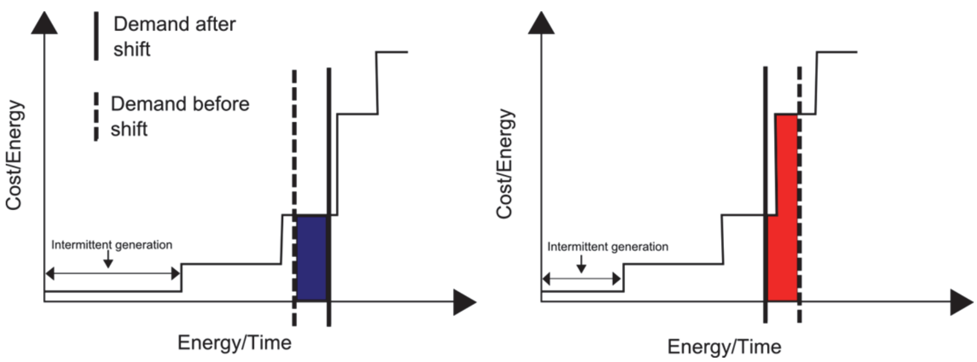

Figure 24.3. *Supply curves for two different hours, one with a high amount of intermittent generation (the left) and one with a lower amount of intermittent generation (the right). The coloured areas are the reduction in system cost (red) and increase in system cost (blue) after a shift of demand from the hour with low intermittent generation to the hour with high intermittent generation. The net effect is a reduction in system cost (the red area is larger than the blue area).*

An important aspect of the design of a RTP scheme is the time difference between the announcement of the price of the power to the customers and the actual consumption of the power. An extended time lag, e.g., using day-ahead pricing, will result in a price that less accurately reflects the demand/supply balance, which may result in an increased need for balancing power. A shorter time lag will better reflect the demand/supply balance but will entail more difficulties for the customers in terms of planning their electricity consumption, since they must forecast the electricity price for the coming day. Since the load profile could vary within different parts of a price area, there is a risk of increasing the peak demand locally. The risk also increases with longer time lags and higher shares of flexible demand. This could be solved by implementing RTP together with some other demand response program, such as power tariffs or locational marginal price (see e.g., Steen et al., 2012).

In summary, there should be several possibilities for demand-response measures in several sectors, but the extent to which these can be applied and under what conditions need to be understood more thoroughly. Furthermore, the design of the price signals to the user and the market design required to get them in place are not straight forward.

Load-shifting potential of electric space heating in Swedish single-family dwellings

In Sweden, the use of electricity in the residential sector accounts for almost 30% of the country's total demand for electricity. A large share of this electricity is used for space heating in single-family dwellings (SFDs). The thermal inertia of buildings implies that there exists certain flexibility with regards to the time of the day when the electrical heating system of the building is operated. If part of this electric load could be shifted in time (load shifting) it would be possible to tailor demand to supply, thereby avoiding or dampening peaks in the electricity generation system and more efficiently exploiting intermittent electricity generation.

To explore this issue, we conducted a study to investigate the current load-shifting potential, based on economic incentives, of electrical space heating in Swedish SFDs using the current electricity price structure and the existing building stock. We assume that hourly spot prices are an adequate indicator of the dynamic load pattern. Since Year 2012, all electricity customers in Sweden have the technical possibility to be debited for their electricity consumption on an hourly basis. We assume that all customers apply this option (based on hourly spot prices) and that consumers respond rationally to these price signals, i.e., strive to move loads from peak-price hours to off-peak-price hours, so as to minimise the cost.

The building stock model ECCABS (described in details in the Method main section) is applied to account for the facts that different buildings have different electricity demand patterns and levels and different possibilities to "store" energy, as given by the thermal inertia. The model calculates net energy demand for space heating, on an hourly basis, for a set of sample buildings in Sweden. The building stock model is complemented by an optimisation model. This add-on model optimises the operation of each sample building's electrical heating equipment with a target to minimise the cost for heating while still satisfying the user's demand for heat (the indoor temperature must be maintained at 21.2°C–24.0°C; Mata et al., 2013).

Two different cases are analysed. The base case assumes that consumers do not act on price variations, rather that the minimum indoor temperature is upheld, which means that no load shifting occurs. The second case assumes dynamic price setting. For this, we apply the historical price data for Sweden in Year 2012 (Nordpool, 2013). Thus, electricity prices fluctuate, which creates an economic incentive for consumers to adapt their load patterns, and the magnitude of the possible economic saving, viewed from the perspective of the consumer, can be estimated. The modelling results for the sample buildings are thereafter aggregated to a national level, and provide the inherent potential for load shifting that exists in the Swedish SFD building stock. In the model, Sweden is divided into different regions, which correspond to the four existing price bid areas (this is the same regionalisation structure that is applied in the EPOD/ELIN model package; see the Method main section for details) as well as several climate regions to account for weather variations.

The preliminary results of the analysis show that there exists a potential to shift the electric load that is destined for space heating in the Swedish building stock. As expected, the largest peak-load capacity that can be shifted occurs during the winter months, when demand for heat is high and electricity prices show the strongest fluctuations. It is estimated that on a national level, up to 3 GW of load could be shifted (which corresponds to about 10% of the peak load in Sweden) from the peak-price hours during this period, which suggests that it is possible to shift approximately 7% of the weekly space heating electricity load during this high-load period. The shares of the load that can be shifted in relation to the demand on a weekly basis are smaller during the Summer (5%), Spring (4%) and Autumn (6%) seasons. However, the suggested strategy of load shifting carries with it the disadvantage of increased total demand for electricity, to compensate for additional losses due to greater differences in the indoor and outdoor temperatures when the time of heating is advanced in time compared to the base case. On annual and national bases, the optimisation strategy is estimated to increase the final electricity demand for space heating in SFDs by about 1%.

Although there exists a potential to shift load, as triggered by the existing difference in electricity prices, the size of the economic savings from the perspective of the consumer is, given current price levels, rather modest (only a small fraction of the total costs of electricity). This is not likely to create sufficient incentives to encourage consumers to invest in the equipment needed to manage the space heat load, so additional policy measures will be required. However, from societal and supply-oriented perspectives, the benefit of load shifting, as identified here, may turn out to be significant. The estimated 3 GW of shifted load should also be viewed against the backdrop of ongoing discussions regarding the necessary peak-load reserve capacity and the possible introduction of capacity markets (see Chapter 23) as means to facilitate the large-scale introduction of variable electricity generation. Load shifting is likely to be a complement to (or even a substitute for) such measures.

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25 DSM increases profitability of distributed solar generation

While there is growing interest in Distributed Solar Generation (DSG), it remains to be determined under which conditions and to what extent DSG will play a significant role in the transformation of the electricity system. In this chapter, we discuss the interplay between Demand-Side Management (DSM) of electrical loads and different pricing schemes with regard to the profitability of DSG in the form of solar photovoltaic (PV) panels in a Swedish context. In this setting, an optimisation model was developed that minimises the electricity cost for individual households by dispatching DSM loads. Different cases and pricing schemes are investigated to reveal the decisive parameters. The results indicate that net metering is the preferred scheme, showing substantially higher economic savings than the other investigated cases at high PV capacities, whereas the difference is small at lower capacities. DSM of hydronic loads (space heating and hot water) is also preferred, showing higher savings than a case in which only DSM of electric appliances is applied.

There is growing interest globally in the rapidly expanding possibilities for distributed solar electricity generation. A major technology for distributed electricity generation is solar photovoltaics (PV). In this chapter, we present the potential role of DSM and how this relates to the implementation of a distributed PV system in a Swedish context. The payment scheme used for selling and buying produced respectively consumed electricity, as well as the correlation between the produced PV electricity and in-house electricity demand will affect the expected benefit derived from a PV installation. Several countries of the EU have the possibility for net metering of the difference between purchased and domestically generated electricity delivered to the grid. For private households in Sweden, monthly net metering is assumed, i.e. a monthly electricity balance and clearance of produced and consumed electricity.

For an hourly purchase and sale pricing scheme, it may be beneficial to use the produced electricity in-house, since a higher level of in-house consumption would lower the total cost of the purchased electricity. However, typically, the electricity production profile of a PV panel and the typical household demand curve are not in phase. Electricity production from PV is usually at a high level around noon when consumption is low, as indicated in Figure 25.1. Thus, if overproduction of electricity is to be avoided, the capacity of the PV panel needs to be dimensioned based on demand around noon hours, as overproduction implies that the excess electricity has to be either stored or exported to the distribution grid. In the case of an hourly purchase and sale scheme, overproduction is undesirable from an economic viewpoint, since it reduces the value of the installed PV system, thereby moving away from the point that is referred to as 'grid parity'. Grid parity is considered the point at which distributed electricity generation can provide electricity at a levelised cost (LCoE) that is less than or equal to the price of purchasing power from the electricity grid. The point at which grid parity is reached varies depending on the electricity producer. A utility needs to compete with the production cost of other utility production sources. Whilst the cost of in-house consumption obviously competes with the cost of buying electricity, which includes the price of the electricity plus extra costs, such as taxes, grid transfer costs, and company overhead costs. Thus, solar PV could become economically feasible for a home producer even though the specific LCoE exceeds that of centralised production. This also implies that the greater the amount of the decentralised electricity production that a home producer can use in-house, the more economical the installation becomes, since the value of one unit of electricity is higher when used in-house than it is when sold to the grid. An increase in the in-house use of electrical power is achievable either through storage of the electricity and/or shifting loads to hours of electricity overproduction. For the shifting of loads, demand side management (DSM) measures can be used.

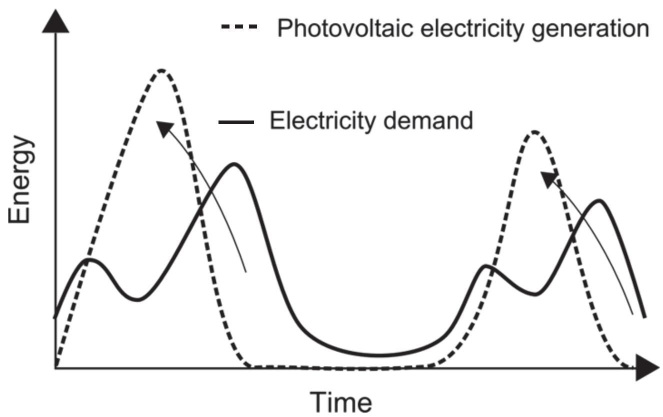

Figure 25.1. The discrepancies between PV-produced electricity and household demand, and an illustration of the concept of DSM (shown as arrows), which involves moving load to hours of overproduction.

Two models are used

The methodological framework consists of two models: the solar PV output model and the household electricity cost minimisation model. The first model, which is a simulation model, calculates solar-PV panel output based on solar irradiance, air temperature, and the specific PV panel technology. The second model, which is an optimisation model, minimises the annual electricity cost for a household. Results from the solar-PV model are used as inputs to describe the PV production profile for a household in the optimisation model. The optimisation model minimises the cost by dispatching DSM loads, if applicable, depending on the cost of purchasing electricity, the PV production profile, revenues from selling produced electricity, and a fixed consumption pattern for non-DSM loads. The result from the model is the yearly electricity cost for the household. The models have a temporal resolution of 1 hour, i.e., solar-PV output and the electricity balance of the household are calculated hourly.

The DSM concept investigated in the present study is load management aimed at reshaping existing load curves, i.e., demand response, whereby the loads in households that are feasible to shift are considered. The model will choose to dispatch the loads to the cheapest hours, i.e., hours with a low price for electricity or hours with a surplus of PV-generated electricity (cf. Figure 25.1). The optimisation model dispatches household loads given appliance-specific constraints. Loads that are assumed to be suitable for shifting are divided into two groups: appliance loads and hydronic heat loads. The first group consists of dishwashers, washing machines, dryers, refrigerators and freezers. The second group shifts loads by storing thermal energy until it is needed; this group includes water heating and hydronic space heating.

Operation of the load dispatch is considered fully automatic. For example, the refrigerator can itself reschedule operations from a high cost time to a time with a lower cost as long as the cooling service is upheld. The applied range of load sizes and assumed duration time for each DSM appliance are presented in Table 25.1.

Table 25.1. Cycle size, cycle duration, and annual shiftable energy of DSM loads; the span represents the difference between households (Zimmermann, 2009).

Load	Cycle size (kWh)	Cycle duration (hours)	Annual shiftable energy (kWh)
Dishwasher	0.67–1.77	2	70–720
Washing machine	0.71–1.64	1	62–350
Dryer	0.89–2.09	1	50–310
Fridge and Freezer (Aggregated)	0.04–0.31 (hourly load)	-	400–1400
Hydronic space heating	-	-	8000–17500
Hot water heating	-	-	1600–3100

Three different pricing market structures are investigated: 1) a monthly (average) electricity price per bought and sold kWh; 2) an hourly electricity price per bought and sold kWh; and 3) net metering, i.e., the monthly net electricity consumption with a monthly electricity price per net kWh.

Four cases are investigated

Four electricity demand cases are modelled, to study the impacts of applying different DSM strategies:

- *No DSM:* without any DSM;
- *Appliance DSM:* with DSM of washing machines, dishwashers, freezer and fridges;
- *Hydronic DSM:* with DSM of the hydronic heating demand (space heating and hot water);
- *Hydronic and Appliance DSM:* with DSM of both appliances and hydronic heating demand.

Table 25.2 describes the different pricing schemes applied to the four demand cases. For the No DSM case, an hourly electricity price, monthly electricity price, and net metering pricing scheme are modelled. For the three other cases (in which DSM is applied to different extents), only an hourly electricity price scheme is modelled, as an hourly price difference is a prerequisite for DSM to be valid.

Table 25.2. Price schemes applied in the investigated DSM cases.

	Monthly price	Hourly price	Net metering
No DSM	X	X	X
Appliance DSM		X	
Hydronic DSM		X	
Hydronic and Appliance DSM		X	

To perform a comparable analysis of households with different sizes of electricity demand, the PV size set-up is based on the array-to-load ratio (ALR). The ALR is defined as the rated peak power of the installed PV panel over the mean load in watts during an arbitrary time period. For each investigated DSM case, five different ALR values are tested: 0.5; 1.5; 3.0; 4.5; and 6.0.

Results

Figure 25.2 shows the average differences in economic savings between the investigated cases, with the *No DSM* monthly price case set as the baseline, for Sweden in Year 2007. Thus, the investment cost of the PV panel is regarded as a sunk cost to compare the different DSM cases and price schemes. The results show that for an ALR of 0, there are no major differences between the investigated DSM cases, although *Hydronic DSM* yields slightly higher savings as the load is shifted to cheaper hours. It is also evident that at low PV capacities, i.e., ALR of 0.5, this difference remains the same, as all the produced PV electricity is used in-house. With increases in the ALR, the price scheme of *Net metering* becomes increasingly advantageous, and for ALRs >1.5, this scheme provides the households with the highest savings of all the cases investigated. Thus, as the benefit of net metering grows with increasing ALR values, it becomes the best measure to apply for supporting high PV capacity installations. The implementation of *Hydronic DSM* and *Hydronic and Appliance DSM*, respectively, give savings similar to those rendered by *Net metering* for ALR values in the range of 0.5-2.0. This indicates that DSM of hydronic loads is just as good at supporting small PV installations as is the implementation of a net metering price scheme. It is also clear that the two *Hydronic DSM* cases provide increased savings at increasing ALRs, and that the advantages of the *Hydronic DSM* cases over the other investigated cases, with the exception of *Net metering*, grow with increasing ALR values, primarily because the amount of shiftable energy is higher relative to the total electricity consumption. The implementation of *Appliance DSM* yields lower savings than the other DSM cases, although somewhat higher savings than the monthly and hourly pricing schemes in the *No DSM* case. The difference between the monthly and hourly pricing schemes for the *No DSM* case is small, with the monthly pricing scheme showing higher savings at low ALRs and the hourly pricing scheme representing a better alternative at higher ALRs.

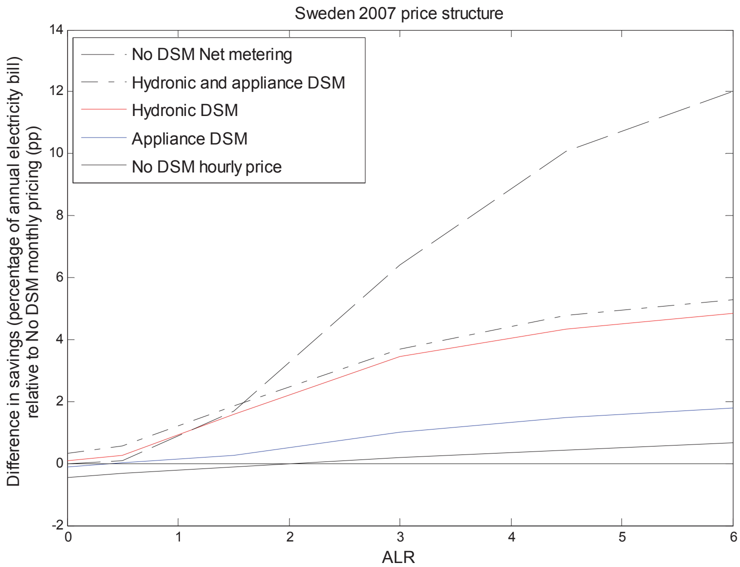

Figure 25.2. *Economic savings given as percentages of household electricity bill saved relative to a base case with no DSM and a monthly pricing scheme. Results shown are for all the investigated cases and for different array-to-load ratios (ALRs).*

Conclusions

Net metering, *Appliance DSM*, *Hydronic DSM*, and *Appliance and Hydronic DSM* are all strategies that have good potentials for improving the economic outcome of investing in solar PV in Sweden. The economic savings associated with the implementation of *Net metering*, *Appliance DSM*, *Hydronic DSM*, and *Appliance and Hydronic DSM* for larger solar PV installations (high ALRs) are estimated at 12%, 2%, 5%, and 5% of the yearly electricity bill, respectively, relative to the use of a monthly pricing scheme. The size of the PV panel, the ALR, influences which scheme will most efficiently reduce the cost for electricity. At low ALR values, in the range of 0.5–1.5, *Hydronic DSM* and *Hydronic and Appliance DSM* are the most profitable measures, although the difference between these measures is small. At higher ALR values, *Net metering* becomes the preferred scheme.

The overall profit derived from investment in a PV panel is dependent upon the cost of investing in a panel, the market price for electricity, and how much of the produced electricity can be used in-house. As the ALR increases, the gains from implementing DSM versus not doing so grow (unless there is net metering); this is because the amount of over-produced electricity increases, thereby enabling more load to be shifted to such hours. However, the gains derived from DSM at increasing ALRs have to be set against the economic loss that may occur as an increasing level of electricity must be sold at market prices that are lower than the LCoE for the installed PV panel. How effective a DSM measure is at countering these losses depends on its size and flexibility. *Appliance DSM* has a limited possibility to augment in-house usage, even with the generous 24-hour load shifting applied in the present study. This is the case because the shifted loads are discrete and require a large amount of energy during a short time-step; the loads also constitute a small percentage of the total electricity demand of the household. This load is likely to decrease further in the future as appliances become more energy-efficient, which will lead to a decrease in the amount of load that can be shifted in time.

Hydronic DSM has strong potential to be a beneficial measure, as its load is larger and more flexible, which means that it is able to adapt itself to overproduction from the PV panel. Shifts of hydronic loads result in an increase in overall energy demand (as thermal losses increase when heating is advanced in time), and while this might be economically advantageous for the homeowner, the increase in demand would imply that a higher level of electricity is produced in the system as a whole.

The *Net metering* scheme can be regarded as the perfect DSM, as, on a monthly basis, all the overproduction can be off-set against consumption. Thus it will always outperform other DSM measures, especially as the ALR increases. However, net metering uses a monthly electricity price, so there is no incentive for the consumer to adapt to the electricity supply system's production pattern. We can also assume that for countries at more southern latitudes the benefits of Net metering would increase as the improved correlation between consumption and PV electricity production across seasons reduces the risk of having months in which production is higher than consumption. The closer match between cooling load and PV electricity production should also improve the value of shifting the cooling load, as compared with shifting hydronic heat.

The PV-panel price will strongly influence at which ALR the maximum economic savings are obtained. As PV-panel prices are reduced, the savings for all measures are increased as the gain from in-house use of electricity increases and the losses from sold electricity decrease. This will also result in an increased optimal ALR for all the cases investigated.

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26 Reduction in transmission congestion through DSM

Transmission grid congestion across Europe could be reduced through the use of demand-side management (DSM). In this study, the extent to which DSM can reduce congestion is shown to be dependent upon: the underlying reason for the congestion; the supply mix on each side of the interconnector; and the DSM measure itself. Thus, DSM in the form of load shifting may become an important factor to consider when planning expansion of the transmission system. This chapter shows that load shifting does not always reduce the need for transmission investments, but rather that the effects of load shifting differ for different connections. The results also show that the level of DSM penetration required to have an impact on congestion differs significantly between connections.

Investigated demand-side measures

The DSM measures presented in the study in this chapter are limited to load-shifting. Different demand delays and different delay times are investigated. Demand delay refers to the amount of electricity load in each of the 50 investigated European regions that can be shifted in time. In this study, 5%, 10%, 15% and 20% of the total load in one given time-step (3-hour load blocks) are investigated. For comparison, the potential to shift the load in households was recently estimated to be approximately 10% of the average total load in Germany (Kohler et al., 2010). The delay time refers to the upper time limit that the delayed demand can be put on hold. After the time limit has expired, the delayed demand has to be served. Delay times of 6 hours and 24 hours are analysed.

The extent to which DSM influence congestion in electricity transmission across Europe is assessed by introducing the concept of system congestion. System congestion evaluates the congestion for the system as a whole, and is defined as the standard deviation of the marginal costs across all regions for a given time-step. A high value for system congestion implies large differences in marginal costs between the different European regions and thus, significant interconnector congestion.

Model results

The results of the modelling for Year 2020 indicate that DSM reduces variations in marginal costs both within the regions over time and between regions across Europe. Figure 26.1 shows the system congestion as obtained from the EPOD modelling across the regions, for

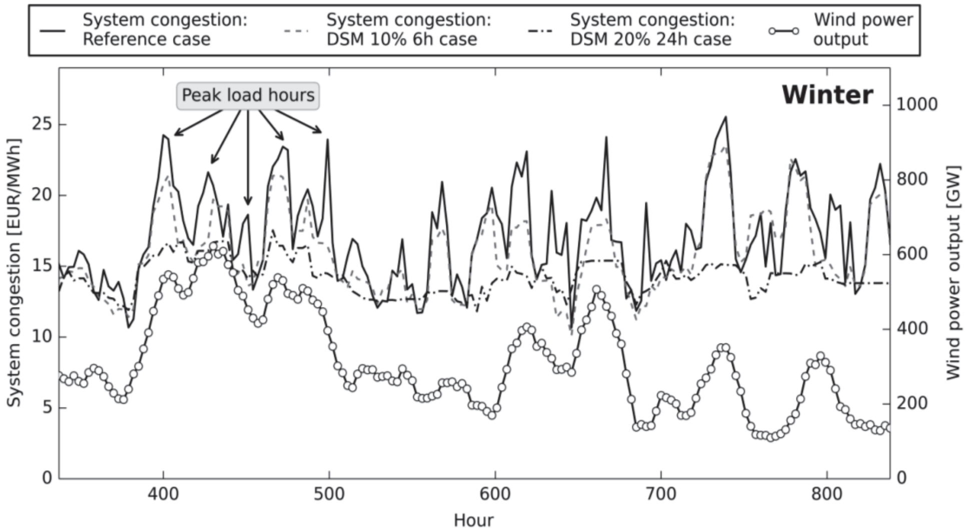

Figure 26.1. Levels of system congestion and total wind-power generation during winter-time, as obtained from the EPOD modelling of Europe. Together with the reference case, cases with DSM are shown with 10% 6-hour load shifting and 20% 24-hour load shifting. Source: Göransson et. al., forthcoming.

each time-step, during 3 weeks in winter[1]. The figure also includes the total level of wind-power generation in Europe at each time-step.

System congestion is generally slightly lower during the summer weeks, as compared with the winter weeks. The peaks in system congestion related to load are also much less pronounced during the summer and as there is less wind-power generation during the summer and, thus, less wind-related congestion, system congestion is reasonably stable with 20% 24-hour load shifting.

Based on these findings, three types of congestion are identified: peak-load-hour congestion; low-load-hour congestion; and all-hour congestion. Peak-load-hour congestion is caused by the increase in desired throughput under high-load situations. Low-load-hour congestion typically occurs if one of the trading regions has high levels of wind penetration. All-hour congestion occurs between regions with fundamentally different supply structures. The relationships between DSM and congestion for these three types of congestion are explored below by investigating the impact of DSM on congestion for a number of selected interconnectors.

[1] The EPOD model is further described in the Method section of this book.

Table 26.1 lists the annual average system congestion from the modelling, along with the total system costs. As expected, the annual average system congestion decreases with DSM, both with respect to penetration level and delay. The impact of DSM on total system costs decreases as the DSM penetration level increases. However, investment costs (or other possible costs) for DSM are excluded from the analysis.

Table 26.1. Annual average system congestion and changes in the system operating cost, as derived from the EPOD modelling for the different DSM cases in comparison with the reference case (source: Göransson et al., 2014)

DSM case				Change in system cost from reference case	
Maximum delay time (h)	DSM penetration level (%)	Annual average system congestion (EUR/MWh)	Total system operating cost (M€/year)	Absolute (M€/year)	Relative (%)
0 (reference)		16.9	14 510.9	-	-
6	5	16.6		-201.9	-1.4
	10	16.2		-337.9	-2.3
	15	16.0		-431.4	-3.0
	20	15.8		-502.8	-3.5
24	5	16.2		-338.4	-2.3
	10	15.7		-548.4	-3.8
	15	15.5		-688.9	-4.7
	20	15.3		-800.4	-5.5

Regional interconnectors

In the model calculations, several interconnectors were identified as being particularly congested (Figure 26.2). In some cases, congestion was reduced through the analysed DSM measures, while in other cases the impact of the DSM measure was only marginal.

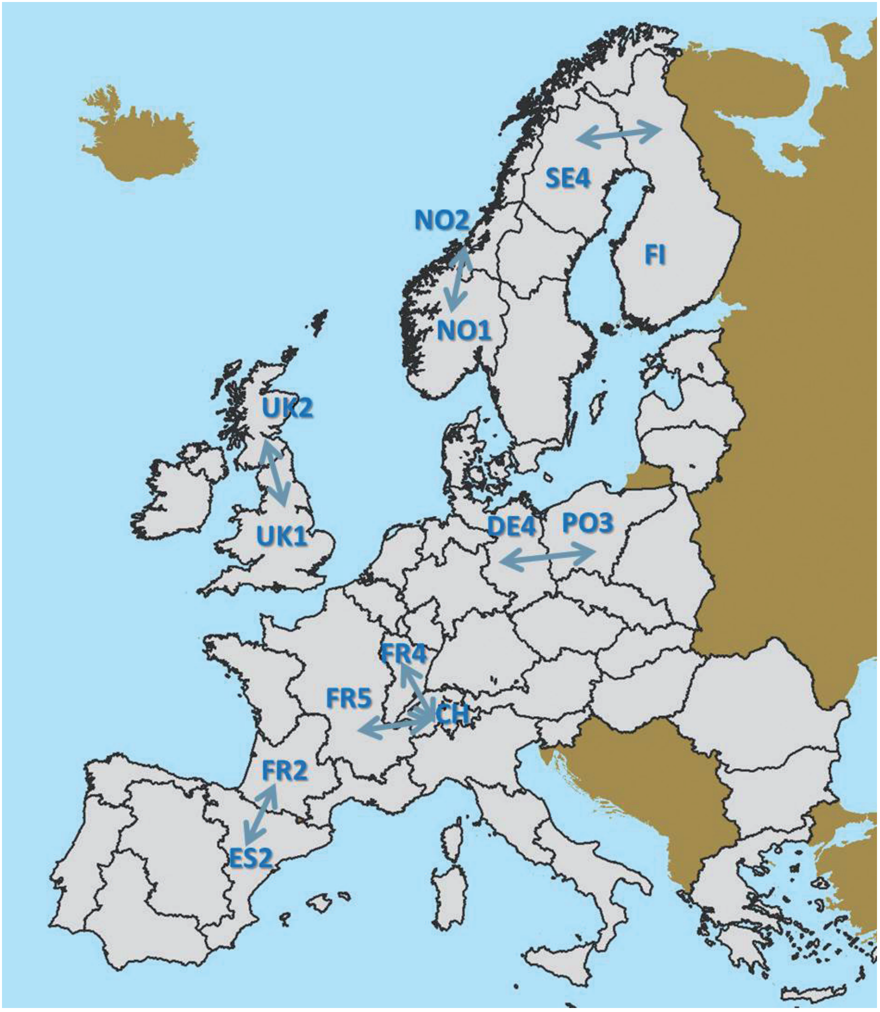

Figure 26.2. Interconnectors with high levels of congestion, as identified by the EPOD-Regional model calculations.

The congestion that occurs between the DE4 and PO3 regions is one example of peak-load-hour congestion. The marginal costs during peak-load hours are substantially reduced by DSM in the PO3 region. Peaks in the marginal costs are also reduced in the DE4 region, and with 20% 24-hour load shifting, the marginal cost in the DE4 region becomes permanently lower than the marginal cost in the PO3 region. The existence of a stable marginal cost relationship between DE4 and PO3 allows for continuous export from Germany to Poland. Congestion is substantially reduced by DSM.

The congestion in the interconnector linking the northern and southern regions of the UK mainly occurs during low-load hours. In the northern UK (UK2), the marginal costs fluctuate between two large plateaus in the supply curve, where wind power or imported gas power (from UK1) is on the margin. As DSM is introduced in UK1, the number of high-cost periods is reduced for this region. Since high-cost periods in the UK are typically periods with high loads and low wind levels, these time periods often coincide with the hours during which UK2 (in Year 2020 UK2 is highly dependent upon wind power), imports electricity from UK1 and the two regions share the marginal costs. Thus, with DSM, the marginal costs are reduced in the two regions for the same time-steps. There is little or no congestion in this interconnector during peak-load hours. Instead, congestion arises during the hours of high wind-power generation when wind power determines the marginal cost in UK2. The level of power exports from UK2 to UK1 is low compared to the load in UK1, and the marginal costs for UK1 remain well above the marginal costs for UK2 during these hours. Since the share of wind-power generation relative to demand is high in UK2, load shifting has a weak impact on marginal costs, and the value of the marginal connection capacity between UK1 and UK2 is sustained for all the DSM.

Similarly, load shifting does not reduce congestion between France and Spain, albeit for a different reason. Given their completely different supply structures (i.e., France is mainly supplied by nuclear power, whereas Spain is mainly supplied by natural gas in the scenario investigated), the marginal costs in southern France are consistently lower than the marginal costs in northern Spain.

The above examples all concern regions that are supplied predominately by thermal generation. For regions that are dominated by hydropower, the impacts of DSM on marginal costs follow different principles, and other relationships between DSM and congestion apply. Due to the storability of hydropower, the marginal costs in northern Sweden correspond to the marginal costs in Finland during low-load hours. Regulatable hydropower is also the reason that the marginal cost difference between low-load and peak-load hours is small in Sweden. In the Finnish system, thermal generation units predominate, and load shifting implies reduced marginal costs during peak-load hours, while the marginal costs increase during low-load hours. The marginal costs in northern Sweden correspond to the marginal costs in Finland during low-load hours also with DSM. Thus, since marginal costs during peak load decrease with DSM in Finland, the differences in marginal costs between northern Sweden and Finland are therefore potently reduced by DSM.

Conclusions

In summary, the model results show that for connections between regions that are dominated by thermal generation, the impact of DSM depends on whether the congestion across the connection occurs during peak-load hours, during low-load hours or during all hours. If the connection is congested during peak-load hours, the DSM are likely to reduce congestion. This is the case because demand is shifted to other hours to reduce the total system costs, thereby creating stable prices and stable price gradients, as well as increased trade across the transmission lines. Congestion during low-load hours is typically due to a large share of wind-power generation in one of the regions involved. With a small local load relative to a large supply of wind power, shifting the local load in time has little impact on the local marginal cost. Thus, congestion is likely to remain despite the introduction of DSM. Thus, DSM has a weak potential to reduce congestion during low-load hours. Congestion between two regions during both peak-load and low-load hours reflects fundamental differences in the supply structures of the two regions. While DSM can reduce the utilisation times of units with the highest running costs in the system, marginal cost differences during low-load events show that the base-load supply structures also differ between regions and that congestion typically persists across the connection even when DSM are in place.

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27 Energy conservation potential in the European building stock

In the EU, the building sector accounts for 35%-40% of the final total energy consumption and 25%-40% of the associated CO_2 emissions. Since turnover of the building stock is low in developed countries, retrofitting existing buildings will be a key measure to reduce energy use in this sector. The impacts of applying various energy conservation measures (ECMs) to the Swedish and the Spanish building stocks, which are representative of northern and southern EU buildings, respectively, are investigated. It is found that the final energy demands of the Swedish and Spanish building stocks could be reduced by 50%. In both countries, the different forms of envelope upgrades confer the largest technical potential reductions for all buildings. However, other ECMs that have significant potentials differ between the two countries and subsectors. The levels of CO_2 emissions from the Swedish residential buildings and the Spanish buildings could be reduced by 60%–70%. Techno-economical potential reductions of energy demand by 20%–30% are identified for Sweden and Spain, corresponding to reductions in CO_2 emissions of 40%–50%. The market potentials identified are substantially lower than the techno-economical potentials. If the techno-economical potentials identified in this work are to be implemented, there will be a need for strong policy measures to influence stakeholders' actions.

Increasing the energy efficiency of existing buildings

In the EU-28 countries, the building sector accounts for 35%–40% of the final total energy consumption (25%–27% residential, 10%–13% non-residential) and 25%–40% of the associated CO_2 emissions (15%–27% residential, 11%–21% non-residential) (EC, 2014; Enerdata, 2014). However, the percentages of CO_2 emissions and energy use (in relation to the total emissions and total energy use of the building sector in the EU Member State) differ among the Member States, owing to disparities in the energy supply systems. For example, Swedish buildings mostly use electricity and district heating, with the electricity being generated from hydro and nuclear sources and the heat being generated from biomass fuels, with the consequence that the levels of CO_2 emissions are low. In contrast, Spanish buildings use, in addition to electricity (which is the most CO_2-intensive carrier in the country), substantial amounts of oil and gas, with the result that the associated CO_2 emissions are high.

Since the turnover of building stock is low in developed countries, the greatest challenge for reducing energy use, and thereby also CO_2 emissions, in the building sector is to find effective strategies for retrofitting existing buildings. While significant potentials for energy savings and mitigation of CO_2 emissions within the building sector have been reported for many countries, these potentials have not been exploited to date (Levine et. al., 2007). Instead, the energy use and associated CO_2 emissions of the building sector in Europe continue to grow[1]. In other words, despite the technical efficacy of energy-saving actions, large-scale implementation of such actions has not taken place. In response to these issues, the European Commission has designed the Energy Efficiency Directive (EED) (EC, 2012), which establishes a common framework of measures for the promotion of energy efficiency within the EU, so as to ensure a 20% improvement in energy efficiency by Year 2020 (as compared to a baseline projection). In this context, understanding the potential roles and costs of different retrofitting strategies is a prerequisite for meeting these energy reduction targets in the building sector.

What does each EU Member State have to do to reduce energy use and CO_2 emissions associated with buildings? Where should they start, and are there clear opportunities that should not be missed? These are some of the questions that are addressed by the research project presented in this chapter (Mata, 2013). The project investigates the large-scale implementation of ECMs in existing building stocks from an energy systems perspective. One of the aims is to quantify the effects of different ECMs in terms of net energy, delivered energy, associated CO_2 emissions, and costs for building stocks in selected European countries. To approach the research questions, a methodology for building stock aggregation (Mata et. al., 2013a) and a building stock model - ECCABS (Mata et. al., 2013b) have been developed, and their application provides a detailed assessment based on the building's specific characteristics and energy system, while also rendering results for entire building stocks. This allows for analyses of aggregated potentials and consequences for the national and European energy systems. The methodology and model are described in greater detail in the Method main section of this book.

Applied energy conservation measures

The building stock model is used to apply various ECMs to the Swedish residential (R) (Mata et. al., 2013c) building stock and the entire Spanish R and non-residential (NR) building stock (Mata, 2013), which are considered representative of Northern and Southern EU buildings, respectively. The ECMs applied include measures such as retrofitting the building envelope, improving the energy performance of the ventilation system, increasing the efficiency of lightning and appliances, and changes to the buildings' energy systems. Table 27.1 lists the ECMs investigated for the two countries' building stocks. Some ECMs influence only a single end-use (e.g., space heating or hot water), whereas other ECMs, such as the installation of heat recovery and increased efficiency of lighting and appliances (ECMs 5–7), exert effects on the net energy demands for both space heating and electricity.

[1] In Year 2008, the EU-15 countries, most of which had certain binding targets, had increased final energy consumption by 15%, as compared to the levels in Year 1990.

Table 27.1. Description of the ECMs investigated in the analysis of the Swedish and Spanish building stocks.

	Description of ECM
ECM 1	Improvement of U-value of cellar/basement
ECM 2	Improvement of U-value of facades
ECM 3	Improvement of U-value of attics/roofs
ECM 4	Replacement of windows
ECM 5	Installation of ventilation systems with heat recovery
ECM 6	Replacement of lighting equipment by more efficient equipment
ECM 7	Replacement of appliances by more efficient equipment
ECM 8	Reduction of hot water demand [1]
ECM 9	Replacement of water pumps by more efficient ones [1]
ECM 10	Reduction of indoor temperature [1]
ECM 11	Installation of solar collectors for hot water production [2]
ECM 12	Replacement of the existing boilers by boilers with an assumed efficiency of 90% [2]
ECM 13	Replacement of the existing gas and oil boilers by biomass boilers with an assumed efficiency of 90% [2]

[1] Only included in the analysis of the Swedish building stock (R buildings)
[2] Only included in the analysis of the Spanish building stock (R and NR buildings)

Technical potential reductions in the building stock through the implementation of individual ECMs

Figure 27.1 summarises the technical potential reductions in terms of reduced final energy and associated CO_2 emissions (as a percentage of the final energy demand in the baseline year, in this case Year 2005), as derived from modelling the ECMs individually in the Swedish and Spanish building stocks. These potential savings are calculated on the assumption that there are no changes in the energy systems with respect to the efficiencies of the different energy carriers.

In both countries, the different forms of envelope upgrade (ECMs 1–4) have the largest energy saving potentials for all buildings (5%–10% reduction for each). However, other ECMs with significant energy saving potentials differ between the two countries and their respective subsectors. For Sweden, the measures that confer the greatest savings, in addition to the envelope upgrade, are those involving heat recovery systems (22% reduction) and lowering the indoor temperature to 20ºC (14% reduction).

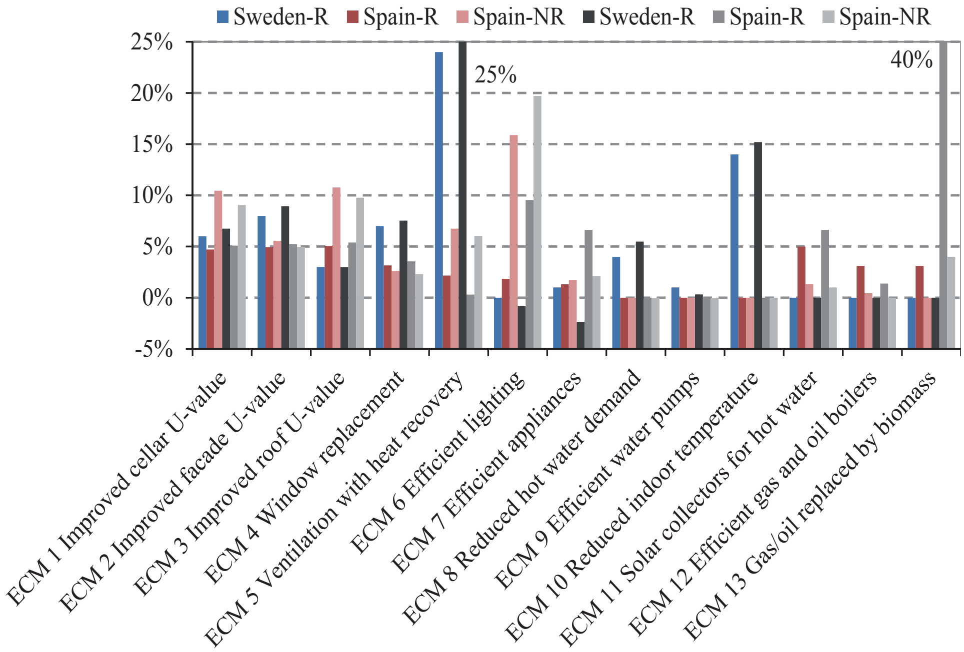

Figure 27.1. *Potential reductions in annual final energy (coloured bars) and associated CO_2 emissions (grey bars), given as percentages of the baseline values (y-axis) for each of the ECMs studied (x-axis) for Swedish residential (R) buildings, and Spanish R and non-residential (NR) buildings, as derived in the present work. Source: Mata (2013).*

In the Spanish case, for R buildings, the modelling results suggest that the installation of solar collectors for hot water production (ECM 11) or boiler replacement (ECMs 12 and 13) each lead to reductions of 5%–7%. For the Spanish NR buildings, the analysis indicates that improving the efficiency of lighting (ECM 6) and the installation of heat recovery systems (ECM 5) give the largest energy saving potentials (7%–16% reductions for each).

The corresponding effects of the ECMs on CO_2 emissions for the Swedish and Spanish stocks range from a 2% increase to a 40% reduction, as compared to the baseline year. The carbon intensities of the fuels are assumed to be the same before and after implementation of the ECMs. For the Swedish case, increasing the efficiencies of lighting and appliances (ECMs 6 and 7) increases the levels of CO_2 emissions, given that the fuel mix[2] for the

[2] Since this deals with reductions, the CO_2 emissions associated with electricity are those for the Swedish generation mix (15 g CO_2/kWh). An alternative approach would be to use CO_2 emissions that are related to marginal electricity production in the Swedish/Nordic electricity market, which would give significantly higher levels of emissions.

reduction in electricity production has a lower specific emission factor than the fuel mix used for space heating. It should be noted that the CO_2 emissions from the Swedish building stock is already very low due to the low carbon content of the energy carriers used for heating and electricity.

In Spain, electricity generation is associated with high CO_2 emissions[3]. Therefore, increases in the efficiencies of lighting and appliances yield the largest potential reductions in terms of CO_2 emissions, since these reductions correspond directly to decreased production of electricity. The replacement of gas and oil boilers with more efficient boilers that use the same type of fuel as used in the existing boiler (ECM 12) has a low potential for CO_2 reduction, in spite of the potential for final energy saving, since the least-efficient existing boilers in the residential sector are not oil- or gas-fired boilers but with biomass-fired boilers, with net CO_2 emissions obviously lower from biomass than from fossil fuels (assuming that biomass is regarded as climate neutral). However, if all the gas and oil boilers are replaced with biomass boilers (ECM 13) there will be a significant reduction in CO_2 emissions (23%). As the results indicate, the potential for reducing CO_2 emissions depends on the fuel mix in the energy system, especially with respect to electricity production. Thus, the potential for CO_2 mitigation through the implementation of ECMs will vary across the EU-27 countries depending on assumptions that pertain to the design of the deregulated electricity market and the cross-border trading of electricity. Moreover, the degree of reduction (or increase) in CO_2 emissions that results from a change in the building stock depends on whether an average or an marginal approach of the production mix is considered when determining the net CO_2 emissions.

Applying ECMs in packages

The potential energy and CO_2 emission reductions in the building stocks have also been assessed using ECMs that are grouped into packages, i.e., several measures are simultaneously implemented. Specifically, the results show that the total annual energy demand of Spanish households could be reduced by 55% by applying all the ECMs in aggregated form, or if the supply from RES is excluded, 48%. By retrofitting only the building envelope (ECMs 1–4), the energy demand could be reduced by about 33%. Improved ventilation (ECMs 4 and 5) and supply from on-site renewables (thermal solar pannels and biomass boilers) (ECMs 11–13) would each give potential energy reductions of slightly less than 10%[4].

Nevertheless, from the perspective of CO_2 mitigation, improved ventilation and the use of RES appear to be as efficient as retrofitting the envelope. All three packages would confer potential CO_2 emission reductions of 20%–25% each, albeit at very different costs. Reducing electricity demand and increasing the use of renewables are key solutions

[3] The value of 649 g CO_2/kWh is used in this assessment for the Spanish mix (IDAE, 2009). The literature gives alternative estimates of 457 g CO_2/kWh for Year 2005 and 297 g CO_2/kWh for Year 2009 (Pagès-Ramon, 2012).
[4] For a detailed description of the aggregated ECM packages, see Mata (2013).

for reducing CO_2 emissions in Spanish buildings. In both Spain and Sweden, the total technical potential for CO_2 emission reductions represents approximately two-thirds of the baseline emissions. However, even though the reduction potential is similar in Sweden and in Spain in relative numbers, the total reduction in absolute numbers is considerably larger in Spain than in Sweden, as emissions from the Swedish building sector (where energy use is dominated by low-emitting electricity and district heating) are already today very low.

The techno-economical potential of conservation measures

If one also considers the economic viability of the ECMs, techno-economical potentials for reducing energy demand by 20%–30% are identified for Sweden and Spain, corresponding to reductions in CO_2 emissions of 40%–50%. The cost efficiency of individual ECMs shows both similarities and differences between the two countries. For example, installing efficient lighting and installing ventilation systems with heat recovery are cost-effective measures in both countries (assuming a marginal cost of energy retrofitting only). While the installation of efficient appliances appears as a cost-effective measure for Swedish buildings, in Spanish buildings this is the least-cost-effective ECM, as the cost of the electricity saved does not compensate for the investment and the increased demand for space heating that is needed to off-set the heat gains from the appliances. However, it should be noted that there are differences in the assumed investment costs of the individual ECMs between the two countries. Moreover, the results of the cost assessments are significantly affected by the choices made regarding cost assumptions, such as taking the full or marginal cost, adopting the tenant or the building owner perspective, and including subsidies in the calculations.

The implementation of ECMs in packages not only increases the technical potential, but the results also show that the lowest levels of final energy demand can be achieved at low cost or cost effectively only by applying packages of ECMs. Application of all the ECMs with or without RES options and improvements to the building envelope and ventilation system are all cost-efficient packages for all the building types analysed. Therefore, there is much to be gained by applying multiple ECMs during the retrofitting of a building, with respect to not only monetary savings, but also because general repairs and renovation activities are usually undertaken only every 25 years.

The market potentials, i.e., the ECMs that can be expected to be realised, have been estimated using private discount rates instead of the societal discount rates that are applied for the techno-economical potential. Private discount rates represent implicit discount rates that include consumer preferences, which reflect consumer willingness to make investments related to ECMs in their homes. It was found that the market potentials identified were substantially lower than the techno-economical potentials. This reinforces the notion that if the techno-economical potentials identified in this work are to be implemented there is a need for strong policy measures to influence stakeholder action.

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28 Can vehicles facilitate renewable electricity integration?

As we have shown, the levels of electricity generated by wind and solar power vary with time, whereas thermal units are at their most efficient if run continuously at rated power. Variations in load and/or renewable generation can be managed through part-load operation and the start-up or shut-down of selected thermal power plants, as well as by curtailing renewable electricity generation. However, part-load operation and start-ups or shut-downs are associated with increased costs and emissions per unit of rated power, while curtailment involves reduced utilisation of low-cost, emission-free generation. Another potentially feasible measure to handle variations due to large shares of variable renewable electricity generation is to include the charging of electric vehicles in the power system demand. Successful integration of electric vehicles could facilitate reductions in both emissions and costs related to the operation of a given power system that has high levels of renewable generation. Furthermore, the utilisation of batteries in electric vehicles or flexibility in charging these vehicles could provide regulating power, which would amplify the benefit.

Introduction

In addition to the options of part-load operation, start-up or shut-down of thermal power plants, and curtailment of renewable electricity generation, electric vehicles present a fourth option for variation management in the electricity generation system, through regulated vehicle charging. With an appropriate charging strategy, electric vehicles have the potential to reduce the need for part-load operation and the cycling of thermal units, as well as to decrease the likelihood of curtailment of renewable generation. The potential of electric vehicle charging to manage variations in the electricity generation system depends on the charging strategy used and the nature of the variations. Variations in demand for electricity follow a diurnal pattern, with low night-time demand for electricity. Electricity generation systems are designed to manage the diurnal variations in demand by allowing some thermal units to have better cycling properties, at the expense of higher running costs. These units are operated only during the day, when demand is highest. At night, only those units that have low running costs and poor cycling abilities remain in operation. By utilising electric vehicle charging as a method to manage variation, cost-effective integration of renewable generation is facilitated. During the day-time, quick cycling thermal units can adapt to renewable generation output with little penalty in terms of efficiency of operation. At night, when demand is closer to the base-load generation output, an excess of renewable generation would likely require either cycling of the base-load thermal units or curtailment of the renewable generation. By implementing night-time charging of electric vehicles, the competition between wind power and base-load units can be avoided. While there are also seasonal variations in wind and solar power outputs, variations that span time horizons longer than 24 hours are unlikely to be managed by vehicle charging, since this requires heavy investment in the battery capacities of the vehicles.

The need for an active charging strategy

The impact of plug-in electric vehicle charging on the electricity generation system of western Denmark has been investigated by Torjman et al., 2014. In that study, it was assumed that the entire private vehicle fleet was made up of plug-in hybrid electric vehicles (PHEVs). The driving patterns of the vehicles were obtained from the Swedish car movement data project (Karlsson et al., 2013). The following *passive* charging strategies, i.e. letting people charge the car at will, were considered: Scenario 1, with possibilities to charge the vehicle when it is paused for ≥10 hours; Scenario 2, with charging possibilities for vehicles that are paused for down to 6 hours; and Scenario 3, with charging possibilities for vehicles that are paused for down to 2 hours. These three different charging strategies correspond to charging infrastructures that are exclusively home-based, both home- and work-based, and present at all major parking lots (including grocery stores), respectively. The three scenarios were compared to a reference scenario without PHEVs, and the loads for households and industry were scaled so that the total annual load was constant in all the scenarios. Figure 28.1 shows the electric load on the western Denmark power system for all scenarios during 1 week. The results show that irrespective of the charging infrastructure, PHEVs cause increases in the afternoon peaks in load on the electricity generation system (cf. Figure 28.1), implying higher cycling costs for thermal generation. To improve the fuel efficiency of the electricity generation system at these penetration levels of PHEVs, active charging strategies are required.

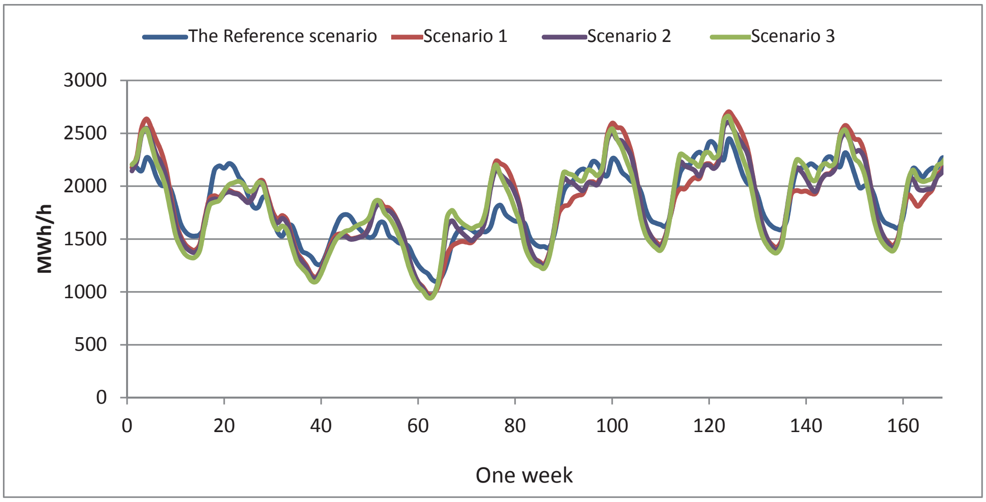

Figure 28.1. *Electricity loads in western Denmark corresponding to the investigated scenarios Source: Torjman (2014).*

Effects of different strategies on the integration of PHEVs with electrical systems

The integration of electric and mobile systems may lower electricity operational costs and emissions, probably as a result of load shifting and increased flexibility, especially for a system that involves intermittent renewable sources of electricity, such as wind power. Using detailed modelling of the operational cost for electricity production in a wind/thermal system, the effects on the production costs of different strategies to integrate PHEVs into the grid were investigated. The simulated production system was the current electricity production system in western Denmark (Jutland). Up to 20% of the load was converted into an electric vehicle-charging load profile. This study shows that PHEVs can reduce CO_2-emissions from the power system if the PHEVs are *actively* integrated into the electricity system. The reductions in emissions are attributed to thermal plant start-ups and part-load operation (Figure 28.2).

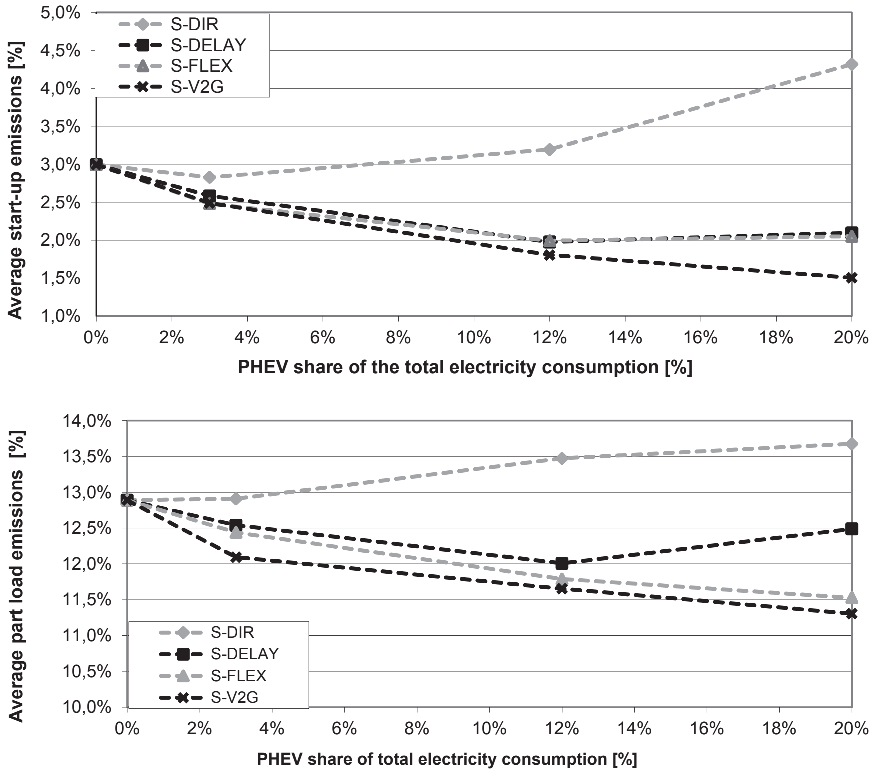

Figure 28.2. *Impacts of different PHEV integration strategies on the CO_2 emission levels of electric systems. The S-DIR strategy means that no action is taken, while the other three strategies represent increasing degrees of active integration. (a) Impact on start-up CO_2 emissions; and (b) impact on part-load CO_2 emissions with the PHEV share of electricity consumption. The value of 100% represents the average system emissions in the system without PHEVs (i.e., 649 kgCO_2/MWh). Source: Göransson et al. (2010).*

According to the simulations, emissions from the power sector were reduced by up to 4.7%, as compared with a system without PHEVs. In addition, the costs were reduced in the case of active integration of the PHEVs into the electricity system.

Opportunities associated with and value of PHEV participation in different regulating power markets

Another option for lowering the costs of the electricity system is the utilisation of batteries or flexible charging to provide regulating power. Simulation of the participation of PHEVs in the different regulating power markets in Germany and Sweden using real prices from these markets and simulation of the vehicle-charging behaviours and associated options have been performed by Andersson et al., 2010. The results of this modelling indicate that the maximum average profits in the German market are in the range of €30 – €80 per vehicle and month, whereas the regulating power market in Sweden produces no profit (Figure 28.3). The observed differences in profitability can be explained by the fact that in Sweden, the market only pays for the regulating power that is actually utilised , i.e., for the transfer of energy, while in the German market, there is an additional payment for having the power available. Thus, the specific structure of the individual market is of profound importance with respect to viability. Although the regulating power markets are generally quite small, the one in Sweden accounts for approximately 400 MW, which means that not all the electric vehicles in a large fleet could participate. Furthermore, the vehicles would need to be pooled for larger power providers due to the minimum power requirements for participation. This would require an institutional infrastructure, an "aggregator", which would organise the pooling system as well as the technical infrastructure. None of these requirements are expected to be met in the near future, which means that regulating power markets are unlikely to be the driving force for transport electrification. The results of the modelling for Year 2020 indicate that DSM reduces variations in marginal costs both within the regions over time and between regions across Europe.

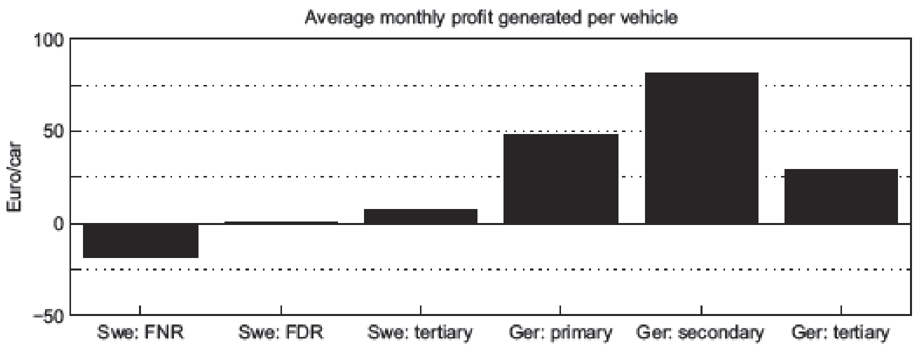

Figure 28.3. *Average profit generated by one PHEV during one month in the regulating power markets in Sweden and Germany. Source: Andersson et al. (2010).*

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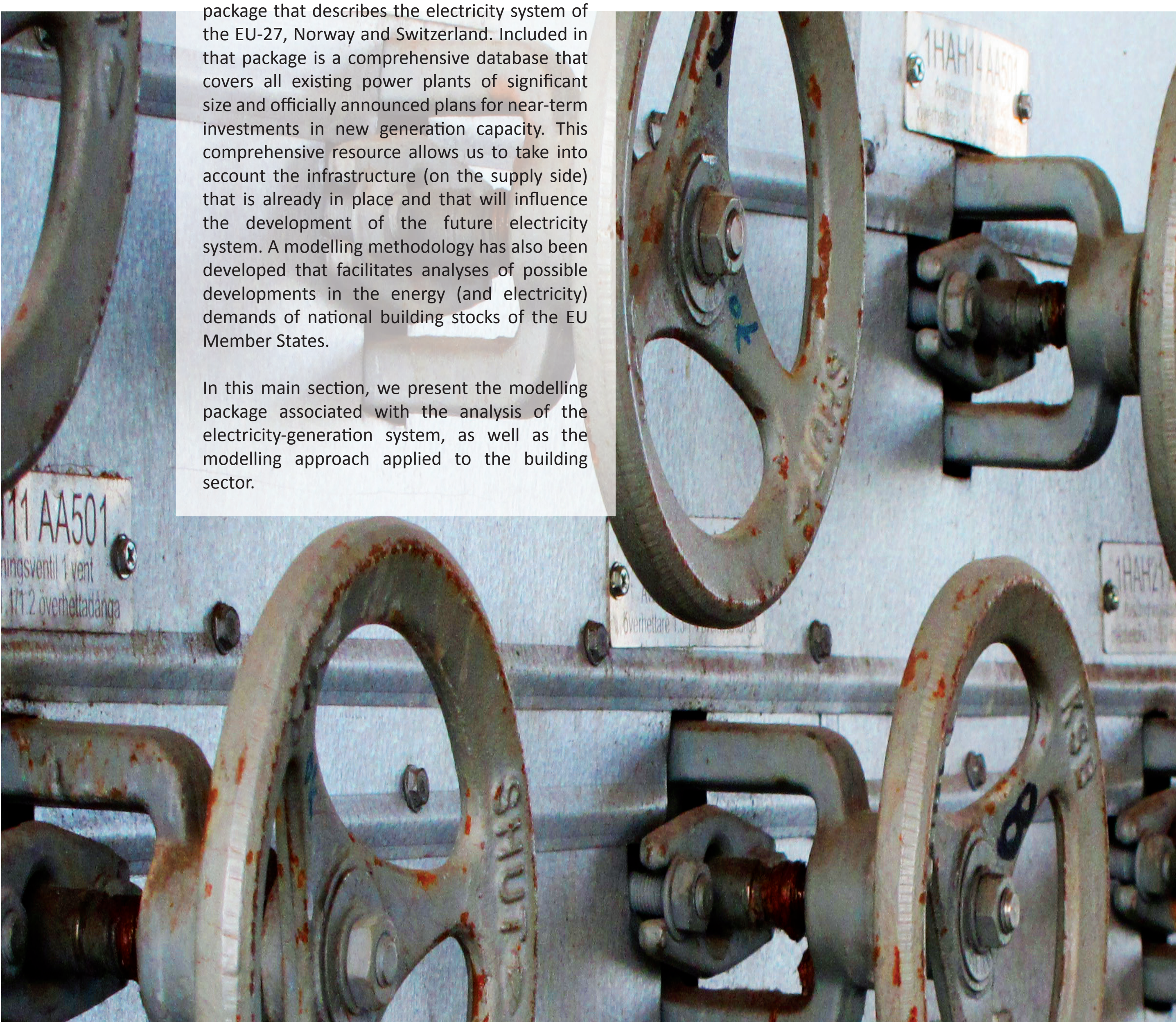
Methods

The research presented in this book relies heavily on an extensive and detailed model package that describes the electricity system of the EU-27, Norway and Switzerland. Included in that package is a comprehensive database that covers all existing power plants of significant size and officially announced plans for near-term investments in new generation capacity. This comprehensive resource allows us to take into account the infrastructure (on the supply side) that is already in place and that will influence the development of the future electricity system. A modelling methodology has also been developed that facilitates analyses of possible developments in the energy (and electricity) demands of national building stocks of the EU Member States.

In this main section, we present the modelling package associated with the analysis of the electricity-generation system, as well as the modelling approach applied to the building sector.



Methods

In this main section we have chosen to describe only briefly the different modelling approaches that have been used in the research work. For a more extensive (but less updated) description of these approaches, as well as the other methods applied to the analyses of other sectors of the energy systems, we refer to the Methods book (Johnsson, 2011), which was issued concomitant with the completion of the first phase of the Pathways research programme, as a complement to this present main section.

The Method main section does not include separate chapters as in the preceding main sections of this book. Instead, the Method section is written as one coherent chapter that describes the used methodology and models tools.

General model overview

The objective of the model package, which has been developed and applied in the Pathways research programme, is to analyse the long-term development of, in particular, the European electricity-generation system, given different assumptions as to electricity demand, reductions in CO_2 levels, fuel prices, policy measures and so forth. The time horizon stretches to Year 2050. Even though the models jointly cover a larger part of the energy system, the focus is on the electricity system. Thus, efforts to develop the modelling have been directed towards the electricity system, with the consequence that there is a significantly higher level of detailed information on this system, as compared to other parts of the energy system.

The model package is linked to several detailed databases, such as the Chalmers Power Plant and Fuel Databases (see the upcoming section). Thereby, the present system and capacity stock are directly linked to primarily the electricity-supply models ELIN and EPOD. The ELIN model is used for long-term analyses of the European electricity-supply system, while the EPOD model is a dispatch model that is applied to one year at a time, but with a higher time resolution within each year. The ELIN and EPOD models are described in greater detail further below. Other sectorial models applied in the research deal with energy use and associated CO_2 emissions in industry and buildings (the building sector being analysed in the ECCABS model, as described below), and assess the long-term development of district heating in Europe (used as input to the ELIN model, as combined heat and power is included in the model framework). The sectorial models are supplemented by more general and overall energy systems models that cover a large part of the overall energy system, albeit with less sectorial-related detail. One example is the MARKAL-Nordic model for energy-system analyses of the Nordic energy system, in which the level of detail related to policy instruments is significantly higher than what is practical to include in the all-European model ELIN. As always, there is a delicate balance between the level of detail and the geographical and sectorial scopes.

The Chalmers energy infrastructure databases: fuel markets and electricity generation

In the Pathways research programme, the analysis of future developments in the European energy systems starts with a detailed description of the existing energy system. Each research group has been involved in creating databases regarding the present situation (in some cases also including historical developments and near-term plans). These databases have incorporated information obtained from different sources, including in-depth interviews, data and literature surveys, available statistics, and direct contacts with, for example, energy utility companies, energy plant owners, and international and national energy agencies. Also included is information from external databases that has been derived from official national and European statistics, EU-funded projects, research institutes, and private companies.

Four such sub-databases are included in the Chalmers Energy Infrastructure database (CEI db). The CEI db describes different parts and areas of the European energy system, both on the demand side and the supply side (Figure I). See Kjärstad and Johnsson, 2007, for a description of an earlier version of the CEI db. Currently, the main sub-databases are: the Chalmers Power Plant database; the Chalmers Fuel database; the Chalmers Industry database; and the Chalmers CO_2 Storage database. The CEI db is being updated on a continuous basis and its scope is gradually being extended. The key features of these different databases are summarised in the textbox on the next page. Moreover, the Fuel database and Power Plant database are presented in greater detail below.

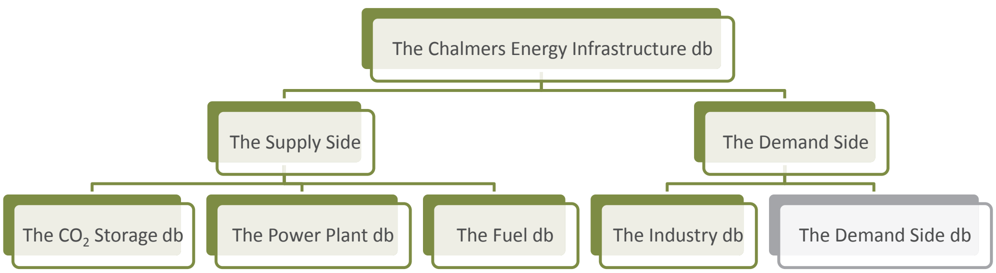


***Figure I**. Structure of the Chalmers Energy Infrastructure database. The databases marked in green are ready to use, while the one marked in grey is under construction.*

Chalmers Fuel database

- Global coverage
- Contains data on coal mines and on coal, gas, and oil fields
- Includes production history, as well as estimates of remaining and ultimately recoverable reserves in oil and gas fields
- Considers global natural gas transport infrastructure, as well as natural gas sales contracts
- Lists exact location of the coal, gas and oil fields by geographical co-ordinates, as well as by name on the local, regional, and global levels
- Chalmers power plant database
- Covers the EU-28, Iceland, Norway, and Switzerland
- Contains all thermal power plants, hydro plants, and offshore wind farms with outputs ≥1 MW; smaller plants (and on-shore wind power plants and solar PV plants) are aggregated by region on an annual basis
- The following items are registered for each plant block: location, age, fuel capacity (thermal and power), technology, present operational status and possible subject to re-powering
- Provides annual levels of electricity generation and CO_2 emissions for most of the plants
- Separates autoproducers from the electricity supply industry and separates combined heat and power from conventional power production.

Chalmers CO_2 Storage database

- Covers all the European countries
- Contains all European gas and oil fields with storage potentials of at least 1 $MtCO_2$, as well as 730 aquifers
- Contains site-specific storage parameters, such as water depth, depth to top reservoir, initial pressure and temperature, formation volume factor, degree of API, reservoir density, R/P ratio, and CO_2storage potential
- Contains annual and cumulative production levels, as well as data on economical and geological reserves (oil and gas fields)
- Lists exact location of the storage locations by geographical co-ordinates, as well as by name on the local, regional, and global levels

Chalmers Industry database

- Covers the EU-27 and Norway
- Covers eight industrial sectors: mineral oil refineries, coking ovens, metal ore roasting or sintering installations, steel or pig iron production, installations for the production of cement clinker or lime, installations for the manufacture of glass, installations for the manufacture of ceramic products, and paper and pulp mills (including production of board)
- Lists exact geographical locations for industrial plants with annual CO_2emissions >0.5 $MtCO_2$
- Contains verified CO_2 emissions and allocated emission allowances
- Includes plant-level characteristics, such as type of production process, fuel mix, capacities, and age

The Chalmers Fuel database

The Chalmers Fuel database (Chalmers FU db), which is included in the Chalmers Energy Infrastructure database (Figure I), covers the fossil fuel sector. The FU db was developed in part because such a database was lacking in the public domain, and in part to provide a comprehensive and detailed overview of fossil fuel resources and capacities, and the relevant transport infrastructure, as well as providing some indications of the dynamics of fossil fuel markets. The primary objective of the FU db is to track future global production capacities for oil, gas, and coal at the country level, as well as the current and future capacities of the transport infrastructures and contracted transport flows. The overall goal is to provide a solid basis for formulating realistic near-term scenarios for development of the energy system.

The Chalmers FU db (Figure II) contains field-specific data for oil, gas, and coal fields, including production and reserve data, as well as data related to fuel infrastructures, for example, pipelines, ports, LNG plants, and gas storage sites. The database includes both existing and planned capacities. Linked to each entry is information on the geographical location, operational status, ownership etc. Although the focus of the Pathways research programme is on the EU-27 countries, the FU db has global coverage, since an understanding of the fuel markets and associated infrastructures must be based on an analysis of the international market.

Currently, the Chalmers FU db comprises the Coal database (Coal db), the Oil database (Oil db), and the Gas database (Gas db), together with associated sub-databases (Figure II). The database is managed in Windows Access with linkage to the Excel software and, when relevant, a Geographical Information System (GIS). The Chalmers FU db and the associated sub-databases have been applied to investigations of specific issues, such as analyses of coal quality in different regions or evaluations of current and future coal export capabilities, as well as to carry out a broader analysis of the development of the fossil fuel markets, at both the European and global levels (see e.g. Kjärstad and Johnsson (2009a) and Chapter 2 in this book).

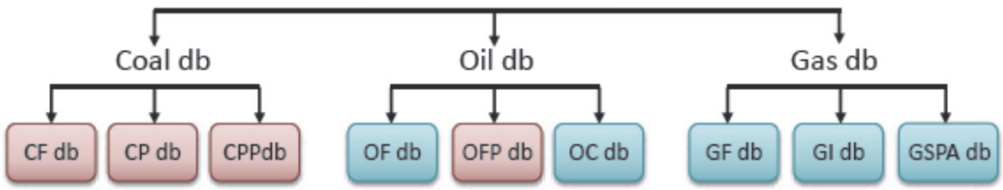


***Figure II**. Structure of the Chalmers Fuel database (Chalmers FU db). The colours used in the figure denote whether the data are continuously updated (blue) or whether the sub-database was established for a specific analysis and is therefore only updated as required by an ongoing research project (red). CF = coal fields, CP = coal ports, CPP = coal-based power plants, OF = oil fields, OFP = oil field projects, OC = oil companies, GF = gas fields, GI = gas infrastructure, GSPA = gas sales and purchase agreements.*

The Chalmers Power Plant database

The Chalmers Power Plant database (PP db) is a part of the Chalmers Energy Infrastructure database. The Chalmers PP db describes the power generation structure in the EU-28 countries, Iceland, Norway, and Switzerland. This comprehensive database was established in part to support a detailed analysis of developments of the European energy system, with special focus on the electricity generation system, and taking into consideration the turnover in capital stock of the existing system and the limitations and possibilities imposed by the infrastructure of the energy system (see e.g. Odenberger et al, 2009a, 2009b and 2010).

The Chalmers PP db includes information on all thermal, hydro, offshore wind, and geothermal plants with power output capacities >1 MW. Plants with capacities <1 MW (or <10 MW for solar PV plants and on-shore wind farms) are combined on a regional basis and annual basis for each fuel or technology. With respect to conventional thermal power plants, the total net capacity of plants that are currently (May 2014) in operation in the EU-28 is 474 GW. For comparison, a total thermal capacity of 497 GW for the end of 2012 was reported by Eurostat (Eurostat, 2014), although according to the Chalmers PP db, at least 13 GW conventional thermal capacity was decommissioned between January 2013 and May 2014 (thus, a rough estimate of a corresponding Eurostat figure for 2014 could be 497-13=484 GW which is very close to what is included in the Chalmers PP db for the same year). In addition, 122 GW of nuclear power capacity and 137 GW of hydropower capacity are recorded in the Chalmers PP db.

All thermal and hydro plants are registered at the unit level with respect to for instance age, capacity (input and output), fuel, technology and present operational status. Moreover, data on CO_2 emissions are provided for many of the plants, whereas data on production levels are derived from the production/capacity data for about 45% of the power plants. The location of each unit is registered using geographical coordinates, together with the name of the location on four levels: *locally*, town or community; *regionally*, administrative province; *country*; and *globally*, global region, e.g., the EU. Figure III shows the geographical distribution by fuel of thermal plants (> 1MW) that are currently in operation in the EU-28, Norway, and Switzerland, and includes an example of the information available in the Chalmers PP db. In addition to the power units in operation, 163 GW of thermal power plants are registered as being under construction or planned, although many of these are unlikely to ever be built. Figure IV shows the capacities by fuel and age for all operational units and plants under construction in the EU, as contained in the database as of the end of Year 2013 (including also wind and solar power).

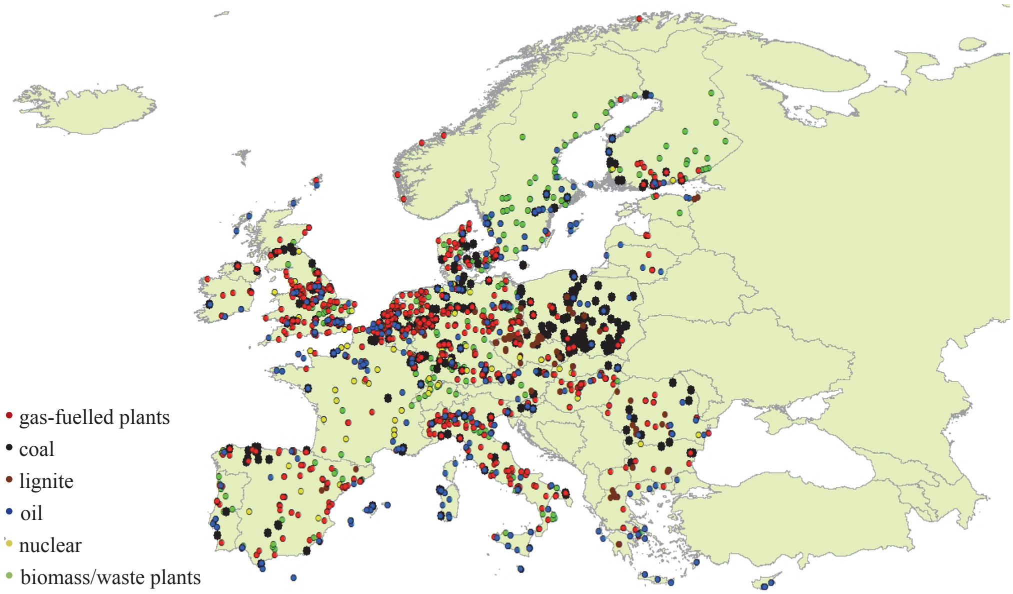


Figure III. *Geographical distribution by fuel of operating thermal plants in the EU (Dec 2012). The figure is a simplification, as a significant number of the symbols represent several blocks.*

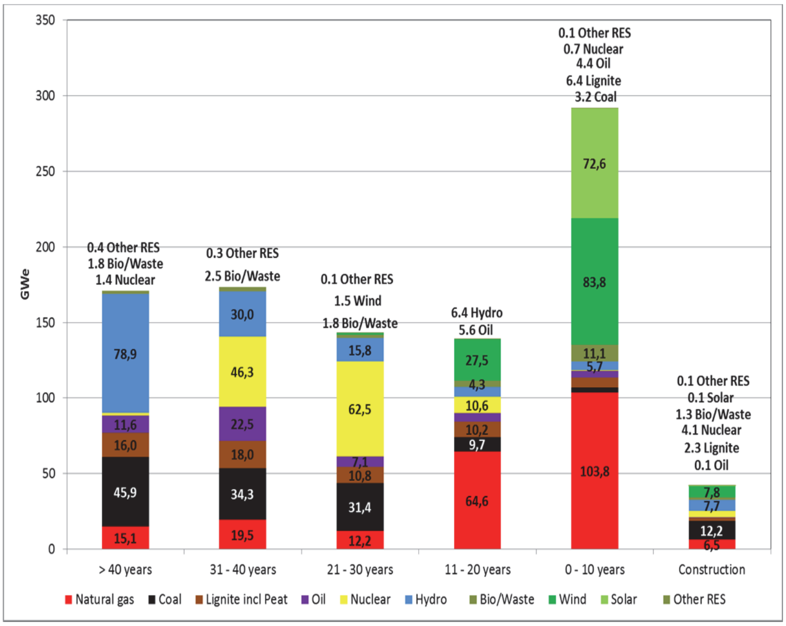


Figure IV. *Thermal power capacities categorised by fuel and age within the EU-27, from data included in the Chalmers Power Plant database.*

In total, 113 GW of operating wind power was registered in the Chalmers PP db as of December 2013, which is slightly less than the corresponding value of 118 GW reported by the EWEA (2014). Regarding solar power, 73 GW of operational capacity has been registered in the database as of April 2014, of which 71 GW is from solar PV and the rest is from solar thermal plants, the latter being located exclusively in Spain. The Chalmers PP database also includes 140 GW of wind power capacity that is under construction or planned, whereby almost 80% of this capacity is projected to be constructed off-shore. As for thermal and hydro plants, plant-specific data and geographical locations are given. In addition to wind power and biomass power, the Chalmers PP db includes other renewable energy power capacities, such as those of power plants based on geothermal, tidal, and wave technologies, although both the registered and installed capacities are currently low (900 MW in operation, corresponding to less than 0.1% of the total capacity in operation; according to the Chalmers PP db, the total installed electricity-generation capacity in the EU-28, Norway, Iceland and Switzerland was around 920 GW at the end of 2013). Most of the data in the Chalmers PP db have been collected through direct contacts with each utility, although other sources, such as national authorities, Renewable UK (formerly BWEA), and IAEA, have also provided important information.

The Chalmers PP db has been applied to analyse developments in the power generation sector and the impact on future fossil fuel demand, and to estimate the potentials of bridging technologies, such as co-firing of biomass with coal and the CCS technology (see e.g. Kjärstad and Johnsson, 2009b, and Kjärstad et al., 2011). The database is also integrated with the ELIN/EPOD model package, so as to take into account the influences of existing and planned energy infrastructures on the possible future pathways of the European energy system (see e.g. Odenberger 2009 and Chapter 10 in this book).

ELIN and EPOD: the electricity-supply model package

As indicated above, the two main model approaches used to analyse the electricity supply sector are ELIN and EPOD. The ELIN (ELectricity INvestment) model is a long-term dynamic optimisation model that describes the present generation system, as derived from the Chalmers PP database, and includes an extensive array of new technologies that are to be used to meet the changes in future demand as existing capacity comes of age or becomes unprofitable. The time horizon of the ELIN model is Year 2010 to Year 2050. Each in-between year is separately described. The intra-annual time resolution of the ELIN model is 16 time-steps, including two daily load segments (night load and day load) for weekdays and weekends. Furthermore, this two-variant diurnal weekly load representation is allocated over four different seasons: winter, summer, spring and autumn. Typical model outputs from the ELIN model include capacity and production levels of electricity by fuel and region (or country) until Year 2050, aggregated investment costs, electricity trade between regions (or countries), and marginal costs of electricity. In general, in the model runs, a CO_2-emission cap, which is gradually reduced as one nears Year 2050, is imposed on emissions from electricity production. Thus, the marginal cost of CO_2-emission reductions is also part of the model output. The fundamentals and the original formulation of the

ELIN model are more thoroughly described in Odenberger et al., 2009a and in the PhD thesis of Odenberger, 2009.

The short-term dispatch model EPOD (European Power Dispatch) analyses in detail a specific year based on the capacities (existing and new) obtained in a preceding ELIN model run. Fuel prices and prices of CO_2 (marginal costs of CO_2 reduction, as obtained using the ELIN model) are also taken from the ELIN model. The dispatch analysis may be conducted weekly, diurnally or hourly. The link between the operation of combined heat and power schemes and the district heating load, as well as cycling properties of power plants are taken into consideration. The typical outputs from an EPOD model run include the production levels of electricity by fuel and region (or country), emissions of CO_2, electricity trade between regions (or countries), and marginal costs of electricity in each region. Thus, the outputs are basically the same as those from the ELIN model, which enables comparisons and quality checks. The main differences between the models are the time perspective (years in ELIN and hours in EPOD) and the possibility for detailed descriptions of power plant operation and transmission bottlenecks in EPOD (discussed in the upcoming sections). Therefore, findings from the EPOD analyses concerning the feasibility and efficiency of the system can be fed back into ELIN, so as to improve the design of that model.

The principal linkages between the ELIN and EPOD models are presented in Figure V. Existing and new electricity-generation capacities for a selected year, as modelled by the ELIN model, are used as inputs to the EPOD model, thereby yielding an electricity-generation output that has significantly higher temporal detail than that achievable using the ELIN model. Thus, capacity investments are made considering the development until Year 2050 and for a relatively coarse intra-annual resolution (ELIN), while the production of electricity is studied in more detail for one year at a time and with a very high intra-annual temporal resolution (EPOD).

The output of the EPOD model, e.g. electricity generation by fuel and country for a specific year, may be directly compared to the corresponding output of a preceding ELIN model run. Thereby, important findings from the considerably higher time resolution in EPOD may be fed back into the ELIN model and, thus, improving the performance and applicability of the latter.

Detailed wind and solar resource data

Included in the ELIN-EPOD model package are highly detailed wind-power and solar-power availability data for across Europe. The data have primarily been taken from the ERA Interim database made available through the European Centre for Medium-Range Weather Forecasts (ECMWF). Although the data were originally defined for single spatial cells of 200–700 km^2 and covering the entire EU-27, they have been aggregated to fit the ELIN-EPOD regional model structure. Both the annual availability (full-load hours) and

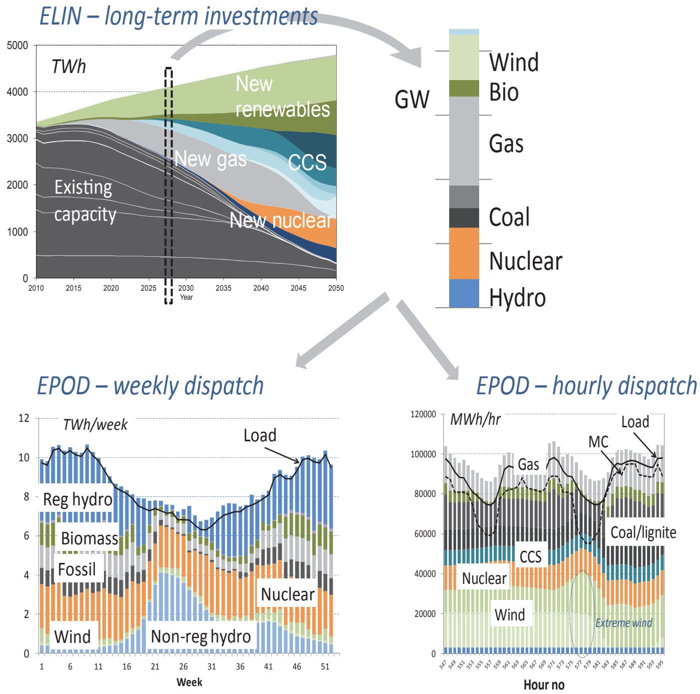


***Figure V**. Linkages between the ELIN and EPOD models within the electricity-supply system model package. The upper panel shows a typical ELIN model result (aggregated) for the entire EU-27, Norway and Switzerland until 2050. The lower left panel shows a typical EPOD model result for the Nordic countries and for a selected year with weekly resolution. The lower right panel shows an output example for an hourly EPOD model run for the German electricity-supply system around 2030 (assuming, in this case, a postponed nuclear phaseout).*

the production profiles (see Figure VI) for wind and solar power have been implemented on a regional level. The estimated potential for wind power, which is also an important model input parameter, follows the principles described in Chapter 8.

Cycling properties of thermal power plants

Another feature that is included as an option in the short-term dispatch model EPOD is to assign thermal power plants with cycling properties. Cycling properties include part-load features, such as minimum load requirements, and start and stop decisions. In general, part load implies reduced efficiency, while the start-up phase of a power plant means that fuel must be consumed for several hours, depending on the type of power plant, without generating any income. In both cases, additional costs are incurred and they have an impact on the operation. This is important to consider, especially for electricity systems with a high share of variable renewable electricity production. To include fully

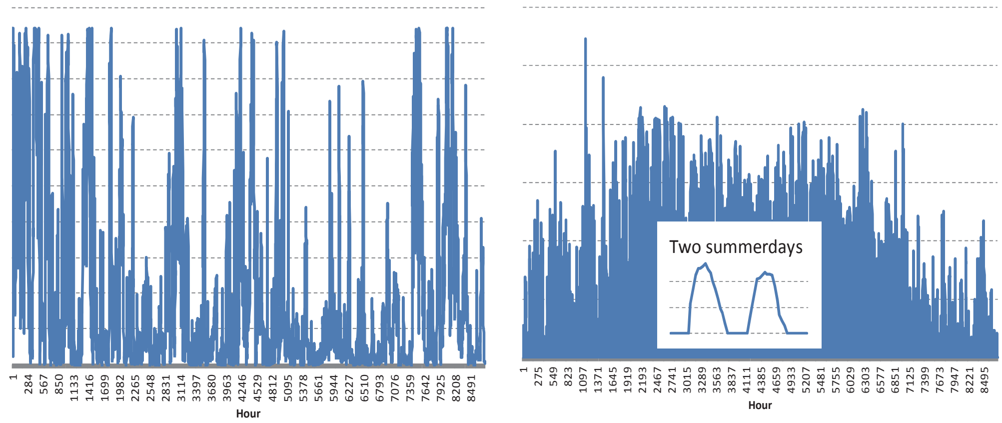


***Figure VI**. Detailed wind-power (left) and PV-power (right) production profiles in a specific region, as applied within the Pathways research programme (a profile for two days in summer is shown to increase the "visibility" of the PV power profile)*

the start and stop decisions, one needs to use (mixed) integer programming. However, this is time-consuming, especially if the system is sufficiently large, which is why we have implemented two somewhat simpler linear approaches into the EPOD model, namely, the two-variable approach and the effective generation approach. These two approaches and other issues related to the inclusion of cycling properties in the EPOD model are more thoroughly described in the PhD thesis of Göransson, 2014. See also Chapter 17 in this book for a discussion on cycling properties.

Regionalisation

Depending on scope, the ELIN and EPOD models can be set up in either national or regional mode. National mode covers 27 of the EU Member States plus Switzerland and Norway (currently, it excludes the 28th Member State, Croatia). The regional mode covers 53 regions across the EU-27, Switzerland, and Norway (see Figure VII). These regions are defined by major bottlenecks in the European electricity-transmission system and the nomenclature of territorial units for statistics (NUTS)-2 areas. NUTS is used for reporting statistics on a regional level[1]. We use GDP data reported at the NUTS-2 level to estimate electricity demand in each region (i.e. the share of the total national electricity demand allocated to each region within a given country). Thus, running ELIN and EPOD used in regional mode may allow detailed analyses that include also transmission-bottleneck considerations *within* countries.

[1] For further details, see: : http://epp.eurostat.ec.europa.eu/portal/page/portal/nuts_nomenclature/introduction

Figure VII. Regionalisation of the EU-27, Switzerland, and Norway in the ELIN-EPOD model package.

Load-flow analyses

Tightly linked to regionalisation is the option to include load-flow analyses in an EPOD model run. The exchange of electricity between two modelled regions is subject to certain constraints. In its simplest form, the constraint is a thermal limit on capacity or, if available, the Net Transfer Capacity (NTC) value. However, in reality, transmission between two nodes in the transmission system also depends on the generation and load situations at each node. Thus, the transmitted or traded electricity flows through a given interconnector (either between regions or between countries) is a model result that reflects the actual generation and load situations at each end of the interconnector. The inclusion of load-flow constraints in the EPOD model is described in more detail in Göransson et al, 2014 and in the PhD thesis of Göransson, 2014.

Other methodologies included in the model package

As mentioned, the ELIN and EPOD models are tightly linked to each other and together form the main part of the model package used to analyse the European electricity-supply system towards Year 2050. More loosely linked to the ELIN-EPOD package are supplementary models that also have been used in the research process. These models focus on selected issues in greater detail and as a consequence, lack the all-European perspective, which is a feature of the ELIN-EPOD package. Some of the outputs from these supplementary model approaches may, nevertheless, be used as the basis for refining certain boundary conditions, e.g., the performance of selected technologies, in the ELIN-EPOD model package.

One example of a supplementary model is a PV solar model for small-scale applications (e.g., in households), which has been developed during the course of the research. This model investigates the incentives that households encounter to invest in solar PV considering the variations in production and in load and considering the different designs of support schemes. The impacts of load shifting, different pricing models for excess production, and subsides are assessed. The optimisation is performed using a mixed integer optimisation approach. Hitherto, the model has been applied primarily to Swedish conditions.

Another example of a supplementary model is the development of a dispatch-type model that includes the distribution of electricity at different voltages. This model is used to analyse further the linkages between transmission and distribution and the role of decentralised electricity production. So far, this model approach has been used only in relation to the German transmission and distribution grid. Decentralised electricity production is, generally, linked to the distribution grid of the electricity-supply system. When there is an increase in the employment of distributed generation, e.g., solar PV on detached houses, the direction of the power flow may change (historically, the direction has been mostly from higher to lower voltage levels), as may the locations of frequently occurring congestions in the grid. Therefore, it is important to come up with a relevant description of the grid subsystems and include this in the analysis methodology and the electricity-system model package. Included in this specific model approach is the interaction dynamics between transmission and distribution networks, and the load characteristics at different voltage levels, as well as the possibilities and technical limitations associated with connecting distributed generation at different voltage levels in the system. In Figure VIII, the electricity loads at three different voltage levels (low, medium and high) are shown for a German distribution network operator. For the low-voltage grid, typical seasonal variations, with high loads during winter and relatively low loads during summer, are observed. The mid-voltage load lacks the same pronounced seasonal variation but instead includes typical load dips during weekends when industrial activity decreases. For the high-voltage grid, there are no corresponding clear seasonal or intra-weekly patterns to the load variations in this case.

Another purpose of the distribution-grid modelling is to provide feedback to the supply and transmission ELIN-EPOD model package. Thus, while ELIN and EPOD are practically hard-linked to each other, the optional transfer of data between the distribution-grid modelling and ELIN-EPOD is achieved through soft-linking.

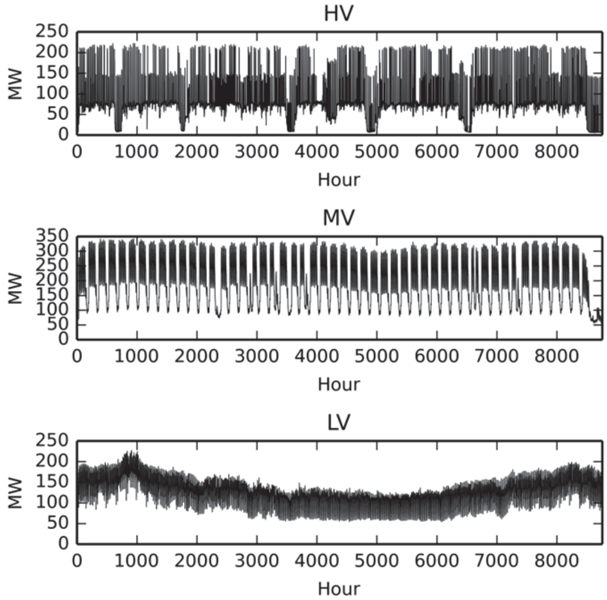


Figure VIII*. Load curves for low, medium, and high voltages (LV, MV, and HV, respectively) for 1 year based on data from one German distribution network operator.*

The ECCABS model: analysing energy demand in buildings

Numerous tools are available for the modelling of building stocks. However, the challenge remains to define the resolution levels that allow a better understanding of the linkages between the different scales, from issues within buildings' boundaries to the interactions between markets and policy. The building-stock modelling approach that has been developed within the Pathways research programme represents a framework that allows a combination (or choice) of different assessments at the reference-building level to be extrapolated to the building-stock level for a different combination (or choice) of outputs. Important is to assess the effects of various types of Energy Conservation Measures (ECM) to the building stocks of the different EU Member States. In the assessment of energy use at the building level, the modelling considers e.g. technical building systems, indoor air environment, and on-site generation based on renewable electricity supply. The variety of outputs is tailored for investigations of energy system issues, climate change mitigation, and policy targets.

A building stock of a country can be described in terms of *sample buildings* or *archetypes*. Sample buildings represent actual buildings for which data regarding thermal characteristics are obtained through measurements. As the building stock of a country consists of buildings with different characteristics, an extensive sample of the buildings is required for derivation of the thermal characteristics of the building stock. Thus, establishment of the sample requires significant efforts for measuring and quantifying the parameters of the building sample. Archetype buildings are instead statistical composites that provide an approximate description of the building stock, based on knowledge of the overall building characteristics within the region (e.g., age, size, construction materials, and house type), in combination with national statistics that relate to the building sector (e.g., energy use and climate). Thus, a methodology has been developed to describe building stocks through archetype buildings. This methodology consists of (see Figure IX): (1) **segmentation**, in which the number of archetype buildings required to represent the entire stock is decided based on criteria that include building type, construction year, heating system, and climate zone; (2) **characterisation**, in which each archetype is described by its physical and technical characteristics; (3) **quantification**, in which the number of buildings in the stock represented by each archetype building is determined.

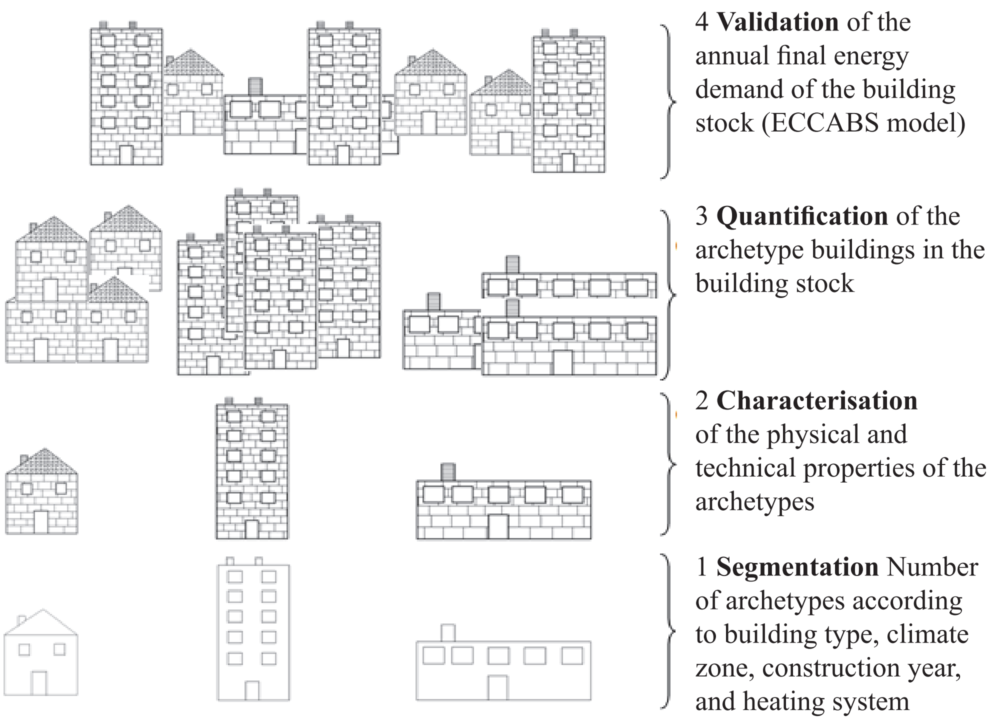


Figure IX. *Illustration of the bottom-up methodology used to describe a building stock through archetype buildings. Adapted from a figure created by Ribas Portella (2012).*

Once the aggregation of the building stock based on archetype buildings is completed, it is used as an input to the Energy, Carbon and Cost Assessment for Building Stocks (ECCABS) model, in which the net and final energy demands for the entire building stock under investigation are simulated. Thus, in the fourth step, the **validation** (4), the building stock description is validated in which the final energy demand and associated CO_2 emissions for the building stock, as derived from the model, are compared with the corresponding values obtained from national and international statistical databases.

The ECCABS model is a bottom-up engineering model that has been developed to assess energy conservation measures (ECMs) and CO_2 mitigation strategies in building stocks, with the aim of making it applicable to any EU Member State. A major challenge associated with bottom-up engineering models is to find a level of detail with a reasonable input data requirement, while retaining sufficient spatial and temporal resolutions to allow investigations of changes in demand and the indoor climate environment. To meet this challenge, the ECCABS model combines a one-zone approach and hourly calculations. The one-zone spatial resolution of the heat-balance implies that the representative building is modelled as a single thermal zone by means of an equivalent volumetric heat capacity. The hourly temporal resolution of the heat-balance allows considerations of the temporal changes in demand that result from occupancy, the use of different appliances, and the effect of solar radiation gains. This level of resolution reflects the complexity of implementing measures that involve management of the building technical systems or user behaviours, and allows analyses of the effects on indoor temperature of applying ECMs. The hourly calculations of the net and final energy demands are thereafter aggregated to annual values. The model is used both to calculate the energy demand for the different end-uses and to estimate the effects of ECMs, for a set of individual representative buildings (either sample buildings or archetypes buildings may be used). The results are then extrapolated to represent an entire building stock of a region or country.

For the **validation of final energy demand**, the aggregated model results have been compared to the corresponding data for the building stocks of France, Germany, Sweden, Spain, and the UK, which are found in the national statistics and international databases. The resulting final energy demand for all countries is in general agreement (within the range of +2% to -7%) with the international statistics.

More thorough descriptions of the ECCABS model and energy demands of the European building stock are available in Mata et al., 2013 and 2014, and in the PhD thesis of Mata, 2013.

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EUROPEAN ENERGY PATHWAYS

Towards a Sustainable European Electricity System

Increasing concern and awareness about global climate change and the security of supply motivate the ongoing transformation of the European energy and electricity systems.

While significant transformation of the electricity system has already occurred in some regions, even greater changes are in prospect if we are serious about meeting the energy and climate-policy targets set by the European Commission. To meet these targets, the European electricity system is expected to take a route towards zero greenhouse gas emissions by Year 2050. Accomplish this transition is a tremendous challenge that involves numerous participants in the electricity market, including utility companies, electricity network operators, retailers, and consumers. Just as important is the political challenge to formulate and implement strong, long-term energy and climate policies.

What is the most efficient route towards an electricity system with close-to-zero emissions of greenhouse gases (primarily CO_2)? What might constitute a future electricity system that is heavily dependent upon renewable electricity generation with significant variation in output? Will renewable energy sources be sufficient and will there be enough sites for the installation of renewable electricity? What are the prospects for other technologies and measures such as carbon capture and storage (CCS), and electricity end-use flexibility?

These are some of the questions that have been addressed by a group of researchers at Chalmers over the past years. Their research spans many aspects of the electricity system and the use of energy associated with the production of electricity. The results of this research are presented and discussed in this book. Key topics include the analysis of pathways for transformation of the European electricity system until Year 2050.

A major conclusion drawn from the research is that we have the technologies and measures required to address climate change. The challenge is political, and we hope that this book will inspire politicians and decision makers to introduce clear and long-term energy and climate policies that will facilitate the energy transition. And we are, of course, all part of the political system.

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