The future role of renewable energy sources in European electricity supply

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A model-based analysis for the EU-15

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Preface

This thesis deals with the development and the application of a modelling approach for the analysis of the future contribution of renewable energy sources to European electricity generation under different framework conditions. These framework conditions particularly include national and European policy measures to stimulate power generation from renewable energy carriers. Interdependencies with other environmental policy regulations and the development of key energy economic parameters, but also physical interactions occuring between fluctuating renewable electricity feed-in and conventional power generation, are taken into account.

The underlying research work was conducted during my time as a research assistant at the French-German Institute for Environmental Research (DFIU) of the Universität Karlsruhe (TH) between 2002 and 2007. It is primarily based on research projects conducted for the European Institute for Energy Research (EIfER), for energy utilities as well as for the European Commission.

I am especially grateful to the head of the institute and the principal examiner of this work, Prof. Dr. O. Rentz, for his continuous professional support, many valuable suggestions and his encouragement. Furthermore, I am indebted to Prof. Dr. W. Fichtner for his willingness to act as the secondary examiner and the thorough examination of the work, as well as for sharing his valuable experience and giving professional guidance in many inspiring discussions.

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Last, but not least, I would like to thank my family and friends, espcecially my parents and Karin, for their continuous support and encouragement during the work on this thesis.

Karlsruhe, November 2007 Johannes Rosen

To my parents

Hildegard & Helmut Rosen

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Nomenclature

In the following, the indices, sets of indices, model parameters and variables are defined, which are necessary for the description of the PERSEUS-RES-E model (in chapter 7). For reasons of a clearer readability the corresponding units are not stated here.

Indices

t	:=	Index of years
$seas$	:=	Index of time slot
$proc$	:=	Index for processes
$unit$	:=	Index for units
$prod, prod'$	:=	Indices for producers
sec	:=	Index for sectors
reg	:=	Index for regions
ec	:=	Index for energy carriers, energy carrier types, and materials
$electr$	:=	Electric power
$heattype$	:=	Index for heat types
CO_2	:=	Carbon dioxide
$kyoID$	:=	Index for CDM-/JI certificate contingents
$bpID$	:=	Index for banking periods
imp	:=	Index for the sources of the graph structure
exp	:=	Index for the sinks of the graph structure

Sets of indices

T	:=	Time periods
$SEAS$	:=	Time slots
$SPRING$	:=	Spring time slots
$SUMMER$	:=	Summer time slots
$AUTUMN$	:=	Autumn time slots
$WINTER$	:=	Winter time slots
$PROC$	:=	Processes
$PROC_{unit}$	:=	Processes of the unit $unit$
$PROC_{prod}$	:=	Processes of the producer $prod$
$PROC_{sec}$	:=	Processes within the sector sec
$PROC_{reg}$	:=	Processes within the region reg

$PROCGEN_{prod,ec}$	:=	Processes of the producer *prod*, which generate electricity using the energy carrier *ec*
$PROCHEAT_{unit,heattype}$	:=	Heat generation process of the unit *unit* to generate *heattype*
$PROCBASE$	:=	Process of energy supply or transformation which is restricted to baseload operation
$PROCDEM_{prod,ec}$	:=	Demand process for *ec* of a producer *prod*
$UNIT$	:=	Units
$UNIT_{proc}$	:=	Units, to which a process *proc* is allocated
$UNIT_{prod}$	:=	Units of the producer *prod*
$UNIT_{sec}$	:=	Units within the sector *sec*
$UNIT_{reg}$	:=	Units within the region *reg*
$UNITGEN$	:=	Power / heat generating units
NUC_{reg}	:=	Nuclear power plants (subset of *UNIT*) within region *reg*
$PROD, PROD'$	:=	Producers
$PROD_{prod,ec}$	:=	Producers, which are the source of flows of the energy carrier *ec* to the producer *prod*
$PROD'_{prod,ec}$	:=	Producers, which are the sink of flows of the energy carrier *ec* from producer *prod*
$PROD_{sec}$	:=	Producers within the sector *sec*
$PROD_{reg}$	:=	Producers within the region *reg*
SEC	:=	Sectors
SEC_{reg}	:=	Sectors in the region *reg*
$TRADESEC$	:=	Sectors participating in certificate trading
REG	:=	Regions
REG_{unit}	:=	Region, within which the unit *unit* is situated
$REG_{RES\text{-}E}$	:=	Regions with targets for the use of renewable energy carriers for power production
$EMISS$	:=	Emissions
EC	:=	Energy carrier (including different forms of useful energy and materials)
EC_{seas}	:=	Energy carrier with seasonally differentiated demand
$EC_{non\text{-}seas}$	:=	Energy carrier without seasonally differentiated demand
$EC_{RES\text{-}E}$	:=	Renewable energy carriers (subset of *EC*)
$HEAT$	:=	Forms of heat (subset of *EC*)
$KYOID$	:=	CDM- / JI certificate contingents

$BPID$	:=	Banking periods
IMP	:=	Sources of the graph structure
EXP	:=	Sinks of the graph structure
$PMAP_{PROD,PROD'}$	:=	Allocation of producers for the pumped storage equation

Model parameters

α_t	:=	Discount factor
$Cinv_{unit,t}$	:=	Specific investment for commissioning the unit $unit$ in period t
$Cfix_{unit,t}$	:=	Fixed annual operation and maintenance costs for the unit $unit$
$Cvar_{proc,t}$	:=	Variable operating costs of the process $proc$
$Cload_{unit,t}$	:=	Load change costs of the unit $unit$
$Cvar_{prod,prod',ec,t}$	:=	Variable transport costs of the flow ($prod$, $prod'$, ec)
$Cfee_{prod,prod',ec,t}$	:=	Variable tax / charges upon the flow ($prod$, $prod'$, ec)
$Cfuel_{imp,prod,ec,t}$	:=	Fuel costs for the delivery of the energy carrier ec to producer $prod$ in period t
$CtransCO_{2,t}$	:=	Transaction costs of the CO_2 certificate trade
$CpenCO_{2,t}$	:=	Penalty for emissions not covered by emission allowances
$Ckyo_{kyoID,t}$	:=	Costs for the acquisition of certificates from the contingent $kyoID$
$\eta_{proc,t}$	:=	Efficiency of the process $proc$
$\eta_{prod,prod',ec,t}$	:=	Transport efficiency of the flow ($prod$, $prod'$, ec)
$VlhMax_{proc,t}$	:=	Limitation of the maximally allowed number of full load hours for the process $proc$ in period t
$VlhMin_{proc,t}$	:=	Specification of a minimally required number of full load hours for the process $proc$ in period t
$FLlev_{prod,prod',ec,t}$	:=	Exogenously specified flow level for flow ($prod$, $prod'$, ec)
$FLmin_{prod,prod',ec,t}$	:=	Minimum flow level for flow ($prod$, $prod'$, ec)
$FLmax_{prod,prod',ec,t}$	:=	Maximum flow level for flow ($prod$, $prod'$, ec)
$FLmax_{prod,prod',ec,seas,t}$	:=	Maximum flow level for flow ($prod$, $prod'$, ec) in the time slot $seas$ in period t (transfer capacities)
$CapRes_{unit,t}$	:=	Capacity of unit $unit$ already installed in period t (residual capacity)
$CapMax_{unit,t}$	:=	Upper limit for the totally installed capacity of a unit $unit$ in period t (including capacity additions)

$CapMin_{unit,t}$	:=	Lower limit required for the totally installed capacity of a unit *unit* in period t
$Capsec_{unit,t}$	:=	Secured capacity share of the installed capacity of a unit *unit* in period t
$MaxAdd_{unit,t}$	:=	Maximum allowed capacity addition of a unit *unit* in period t
$Avai_{unit,t}$	:=	Average availability of a unit *unit* in period t
TLT_{unit}	:=	Technical lifetime of a unit *unit*
$KLev_{unit,t}$	:=	Given share of a process related to the total output of the corresponding unit
$KMax_{unit,t}$	:=	Allowed maximum share of a process related to the total output of the corresponding unit
$KMin_{unit,t}$	:=	Required minimum share of a process related to the total output of the corresponding unit
$EmissProc_{CO_2,proc,t}$	:=	Emission factor for process-related emissions
$EmissFl_{CO_2,prod,prod',ec,t}$	:=	Emission factor for flow-related emissions
$Emissrights_{sec,CO_2,t}$	:=	CO_2 emission allowances of a sector *sec* in period t
$Emissmax_{reg,CO_2,t}$	:=	Emission ceiling of a region (concrete ceiling)
$TradeMax_{reg,CO_2,t}$	:=	Limitation of the allowed certificate sales of a region
$KyoMax_{kyoID,t}$	:=	Upper limit of the allowed external certificate contingents *kyoID*
$bplow_{bpID,}$	:=	Starting year of the banking period *bpID*
$bpup_{bpID,}$	:=	End year of the banking period *bpID*
$f_{proc,t,seas}$	:=	Load profile of a demand process: weight of the time slot *seas* as related to the total annual demand
$\lambda_{proc,\ ec}$	:=	Share of energy carrier *ec* related to the total input / output of a process *proc* (convention: negative sign for input, positive sign for output)
$NucMaxCap_{reg,t}$	:=	Maximum allowed installed nuclear capacity of a region in period t
$NucMaxProd_{reg}$	:=	Maximum allowed remaining nuclear production in a region
Reserve	:=	Reserve factor
h_{seas}	:=	Number of hours that are represented by the time slot *seas*
h_{year}	:=	Number of hours of one year (8760h)
$No_{seas',seas}$	:=	Number of transitions between time slots *seas'* und *seas* in the course of one year

$\Omega_{proc,t}$	:=	Power production equivalent
$years_t$	:=	Number of years within period t
$HGF_{unit,t,seas,heattype}$	:=	Load profile of heat demand
$RESe\text{-}target_{reg,t}$	:=	Target for the increased use of renewable energy carriers for power generation in region reg and period t
$Rcap_{(pr/sr)tr,unit}^{max}$	:=	Maximum contribution of a unit's capacity to a type of reserve
$Rdem_{(pr/sr)tr,reg,seas,t}$	:=	Total demand for a type of reserve in a region reg in a time slot $seas$ in period t

Positive variables

$PL_{proc,t}$	:=	Activity level of a process $proc$ in period t (annual value)
$PL_{proc,t,seas}$	:=	Activity level of a process $proc$ in the time slot $seas$ in period t
$LVup_{unit,seas',seas,t}$	:=	Positive load change (auxiliary variable)
$LVdown_{unit,seas',seas,t}$	:=	Negative load change (auxiliary variable)
$FL_{prod,prod',ec,t}$	:=	Level of the ec-flow from producer $prod$ to producer $prod'$ in period t (annual value)
$FL_{prod,prod',ec,t,seas}$	:=	Level of ec-flow from producer $prod$ to produer $prod'$ in time slot $seas$ of period t
$Cap_{unit,t}$	:=	Installed capacity of a unit $unit$ in a period t
$CapNew_{unit,t}$	:=	Newly installed capacity of a unit $unit$ in period t (capactiy addition)
$Emissvol_{sec,CO_2,t}$	:=	CO_2 emission volume of a sector sec in period t
$Emissloss_{sec,CO_2,t}$	:=	Lost CO_2 emission rights of sector sec in period t
$Emisspen_{sec,CO_2,t}$	:=	Penalised CO_2 emissions of sector sec in period t
$Emissaux^{+}_{sec,CO_2,t}$	:=	Procurement of emission allowances (auxiliary variable)
$Emissaux^{-}_{sec,CO_2,t}$	:=	Sale of emission allowances (auxiliary variable)
$KyoCert_{kyoID,t}$	:=	Procurement of external certificates
$Rcap_{(pr/sr)tr,unit,seas,t}$	:=	Contribution of a unit's capacity to a type of reserve in a time slot $seas$ in period t
$Rdem_{(pr/sr)tr,reg,seas,t}^{wind+}$	:=	Additional demand for a type of reserve in a region reg due to wind energy use
$Rcap_{tot,unit,seas,t}$	:=	Total contribution of a unit's capacity to all types of reserves

Free variables

$\Delta Emiss_{sec,CO_2,t}$	:=	CO_2 certificate trading volume of sector sec in period t

1 Introduction

1.1 Motivation

The integration of substantial amounts of renewable energy sources implies one of the major strategic challenges for the European electricity supply system, next to the continued liberalisation process and climate change mitigation efforts. While specific goals for each EU Member State are already set in Directive 2001/77/EC to increase the renewable electricity share from currently 13.9% to 22% in 2010, much more ambitious, but at the time of writing not yet official targets are envisaged for 2020. A further development of power generation technologies based on renewable sources of electricity is generally regarded as a step towards sustainability within the energy sector, as the use of renewable energies contributes among others to the protection of natural resources and to climate change mitigation, but also reduces dependencies on imported fossil and nuclear fuels.

The introduction of policy objectives for an augmented use of renewable electricity further increases the existing uncertainties in liberalised electricity markets. Additional uncertainties exist e.g. concerning the level of longer term national or European targets, but also regarding the possible choices of strategies for the achievement of those targets. The current discussions about the adequacy and the precise design of policy instruments as well as their effectiveness, their efficiency, and the necessary degree of coordination on a European level, reflect these uncertainties. Decision makers in utilities as well as policy makers are challenged to meet the entire set of the above energy sector framework conditions with adequate competitive strategies and policies. In order to develop these strategies, they must be able to consider the interdependencies and future consequences of their decisions. Within energy utilities all divisions are more or less affected by the structural changes. However, the implications are most important for investment and production planning, which are of essential relevance for the future economic success of a company.

Although the efficiency and reliability of renewable technologies has continuously been improved, the politically and environmentally motivated introduction of significant amounts of renewable sources of energy into the electricity system still depends on incentive schemes. Under the current market conditions and without these support instruments the majority of renewable potentials for electricity generation is not yet competitive, and this is likely not to change for the short- to mid-term future. While the geographically inhomogenous availability of renewable energy potentials is naturally given, the temporal evolution and the geographical distribution of renewable electricity market penetration is influenced by the different design options for national promotion schemes. The design of these schemes and their possible future harmonisation crucially determines the resulting competitiveness of renewable electricity generation technologies with conventional generation options. Conversely, the future cost structure of conventional electricity generation, i.e.

especially the evolution of fossil fuel prices, but also the stringency of CO_2 emission restrictions, have an influence on the rentability of renewable electricity generation and the necessary support. Further, physical interdependencies between renewable and conventional power generation exist due to the fluctuating and non-schedulable characteristics of wind energy as a major source of renewable electricity.

A comprehensive assessment of the future penetration of renewable electricity thus needs to take into account renewable power production in the context of the entire electricity generation infrastructure under the changing framework conditions mentioned above. For a quantitative consideration of all relevant aspects and framework conditions within electricity sector planning or political decision making, adequate methodologies to address the arising demand for information concerning all relevant economic, technical, ecological, and political developments, are thus of essential importance.

1.2 Objective and methodological approach

The objective of this work is to develop and apply a methodology for a quantitative assessment of the long-term role of renewable electricity production under varying framework conditions within the liberalised European electricity market. In order to account for the occurring effects and interactions this assessment shall be carried out in a model-based approach, covering the energy systems of the EU-15 Member States.

From this objective and the framework conditions characterised above, essential requirements result for the methodology to be applied. The modelling approach to be developed shall be able to account for a detailed representation of renewable electricity generation within a technology-based representation of the energy supply system, and thus allow for qualified quantitative statements concerning the temporal, regional, and technology-specific profiles of renewable electricity production. Next to the penetration of renewable technologies in terms of capacity and power production, the costs and emissions associated with the renewable and the conventional parts of electricity generation, shall be assessed.

Due to the increasingly internationalised European energy markets with their multiregional market structure and their linkage with the European emission CO_2 certificate market, the analysis shall comprise the EU-15 and relevant neighbouring states to give adequate consideration to the interregional power exchange and certificate trading options. In doing so, intertemporal relations between investment decisions and production characteristics must be considered in the form of an integrated capacity expansion and power production planning.

Furthermore, the methodology shall give special consideration to the physical interactions that occur due to increasing shares of fluctuating renewable electricity production, especially from wind energy, and evaluate the immediate as well as the long-term net economic and ecological benefits of this renewable electricity generation technology.

Pursuing these objectives, the following proceeding has been chosen:

In chapter 2 an overview is given over the framework conditions for power generation in the liberalised European electricity market.

The evolution and the current situation of renewable electricity generation in Europe is described in chapter 3. Further, the focus of this chapter is on the available mid-term potentials and the political and financial framework conditions for renewable electricity generation, which determine the current and future role of renewable energy sources within electricity generation.

Chapter 4 describes the special characteristics of power generation from renewable energy carriers, and the implications of their integration into power generation from a physical and an economic perspective. In this context, special consideration is given to fluctuating renewable electricity production.

Based on a review of different modelling approaches for renewable electricity generation, a hybrid modelling concept is derived in chapter 5, which enables to consider the implications of the long-term development and the short-term variations of renewable electrictiy generation in strategic energy system planning. While the implications of the short-term fluctuations are analysed in a simulation model, the long-term development is assessed in an optimising energy system model.

The logical description and the structure of the developed simulation model for the assessment of fluctuation-induced effects are introduced in chapter 6. Considering the interactions of renewable and conventional electricity generation, its application to determine the net economic and ecological benefits of fluctuating renewable power production is demonstrated. Further, the coupling of this complementary approach with the long-term energy system model via a soft link is explained.

The development and the formal description of the long-term optimising energy system model is the subject of chapter 7. Both conventional and renewable energy technologies are considered in this approach. Aiming at an adequate representation of renewable electricity generation in a long-term energy system model, the focus is on a sufficiently detailed representation of the available potentials of renewable technologies and their interactions with conventional power generation. These are derived from the complementary short-term simulation model and existing scientific documents. The methodology chosen is furthermore intended to allow for an integrated consideration of all relevant planning tasks, regarding investment strategies, power plant operation, interregional power exchange, and CO_2 emission trading.

Chapter 8 gives a description of the necessary input data and the structure of the developed model. Renewable potentials for a total of 15 renewable energy carriers, including e.g. wind energy, biomass and photovoltaics, are modelled in a detailed way and implemented as individual units in each country of the EU-15, along with existing conventional power plants and future expansion options combined in technology classes.

In chapter 9 the results from the application of the developed complementary modelling approach in a model-based analysis of the European electricity system are described. Firstly, a reference scenario for the future evolution of the European power sector is introduced. Subsequently, the results of different scenario calculations are described and analysed. The varied assumptions in the scenarios comprise alternative design options for renewable electricity promotion schemes, as for example national or European targets for the use of renewable energy sources in power production. Further, the relevant energy sector framework conditions like CO_2 emission allowance constraints or different developments of fossil fuel prices are taken into account. Finally, the additional conventional reserve capacities and the operational efficiency losses caused by fluctuating wind power feed-in are given special consideration.

In chapter 10 conclusions are drawn with respect to the developed hybrid modelling approach and the achieved model results. Additionally, other possible applications of the developed models are sketched in an outlook, which finally also introduces promising modifications for further developments based on the current versions of the models.

The thesis closes with a summary in chapter 11.

2 Power generation in the framework of the European electricity markets

A secure and economically efficient energy supply plays a fundamental role in the development of modern industrial societies. Thus, governments have always had the desire to control its development and exerted strong political influence on the sector, imposing regulatory frameworks. While the political influence formerly was primarily national, it is nowadays initiated more and more by institutions of the European Union. Substantial changes of the political and legal framework conditions of the energy sector have been caused by a number of developments throughout recent years, of which the most important one is the liberalisation of energy markets. Moreover, other sources of political and economic insecurities exist, such as the introduction of the EU Emission Trading Scheme (ETS), the promotion of renewable energy utilisation for electricity generation (RES-E), as well as - on a national scale - e.g. the German nuclear phase-out policy. In the following sections, a description of the most important structural changes due to recent energy- and climate policy interventions shall be given.

2.1 Liberalisation of the European electricity markets

With the entering into force of Directive 96/92/EC concerning common rules for the internal market in electricity [EC 1996, p. 7 ff], on 19 February 1997, fundamental changes of the competitive environment of energy utilities took effect, which have lead to major structural rearrangements. The aim of the framework directive is to create a free and competitive single European electricity market by restructuring of the monopolistic energy market structures with clearly separated demarkation areas for the supply of each utility. Its intention is thus to spark an increased level of competition and to raise the efficiency of European energy supply.

The stipulated measures to realise this goal are a stepwise opening of markets for electricity. Beginning with the largest consumers, customers are guaranteed the right to freely choose their electricity supplier. Moreover, a free and guaranteed grid access for power producers[1] is aspired, especially for new market entrants like independent power producers. Further, a legal and organisational separation (unbundling) of the business areas generation, transmission and distribution is manifested, which includes separate accounting. Finally, the Member States are obliged to create mechanisms for market regulation, control, and for ensuring

1 Basically, two models for a non-discriminatory grid access exist, the so called negotiated third party access (nTPA) and the regulated third party access (rTPA). A third model is the single buyer model (especially chosen by local utilities). With the exception of Germany, all Member States have realised a regulated third party access with standardized tariffs, whereas Germany basically decided upon the negotiated third party access with negotiated tariffs under a governmental framework.

transparency in order to avoid the abuse of dominant positions in the market at the expense of the final consumers.

Major expectations were connected to the introduction of competition into electricity markets (cf. e.g. [IEA 2005a, p. 16]). An important intention is the reduction of overcapacities, which helps to improve the economic efficiency of the sector and thus should have an impact on power prices, reducing the financial burden for consumers. While the formerly prevailing regional or national monopoly situation has been characterised by low or no market risk at all, i.e. with a good predictability of demand, and with the possibility to increase prices when necessary to recover additional costs not anticipated at the time when the investment decision was taken, the electricity market reform has changed the decision making premises for investments in the power sector due to the inclusion of market risks and uncertainties.

A temporally staggered schedule was implemented for the market opening process. While for the first three years after the directive entered into force, the free choice of a supplier was mandatory only for customers with an annual consumption of more than 40 GWh/a, the threshold was lowered to 20 GWh/a after those three years. Finally, it was only 9 GWh/a after a further three years (see Article 19 of Directive 96/92/EC).

While in principle the Commission expresses its satisfaction with the progress of liberalisation efforts in its second benchmarking report on the liberalisation [EC 2002] still a number of areas are identified where further actions are necessary:

- Unbundling of generation and transmission has only been achieved to a limited extent.
- The still remaining market power of individual companies obstructs the market entrance of new market participants and impairs the development of a functioning free competitive market.
- Electricity exchanges between different grids are physically limited by transmission bottlenecks in the existing grid infrastructure.
- From an economic point of view, the cross-border trading of electricity is complicated by differing degrees of market opening and the inhomogenous calculation of fees for the utilisation of the grid infrastructure[2].

Also the third [EC 2004c] and fourth [EC 2005a] benchmarking reports of the Commission acknowledge the progress made on the way to liberalised electricity and gas markets[3]. However, the third benchmarking report states critically that electricity markets are still too strongly dominated by national utilities, while the fourth report

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[2] Fees related to the cross-border transmission of electricity were abolished in 2003.

[3] In 2003 Directive 96/92/EC was repealed by Directive 2003/54/EC [EC 2003a], which addresses many of the issues identified necessary to be improved as a result from the experience with the original Directive.

emphasises the increasing importance of a competitive European market before the background of rising primary energy carrier prices.

In a liberalised market utilities do not necessarily fulfill the demand of a confined area any more, but find themselves in a free competition for the combined European power demand, where customers have to be found and bound in direct comparison with European competitors[4]. These new market conditions favour power plants that can react flexibly to the market requirements, i.e. power plants with short payback periods (low investments) and a modular design. Typically, these are natural gas fired combined cycle power plants instead of coal-fired or nuclear power plants[5].

Numerous national and European policy measures exist, which aim to overcome the above mentioned problems of a single European electricity market. For long-term assessments of the energy markets it can thus be assumed that the still existing problems will be of minor and steadily decreasing importance. As the only exception the long-term development of the grid infrastructure can be seen.

With the liberalisation process focussing on economic efficiency, it has to be ensured that a liberalised energy market also takes into account the other two major premises for energy supply, i.e. security of supply and environmental compatibility. While environmental compatibility is ensured by a framework of laws and regulations governing the installation and operation of energy conversion units, the economically desirable free trade of electricity has to respect existing physical and technical constraints. Otherwise, the safe operation of the system is at risk. Especially in the context of the liberalisation of the grid infrastructure, which is of special relevance for the security of electricity supply, criticism and warnings have been expressed. It is argued that increasing the free trade of power across Europe can lead to a decrease of overall system security, especially by an aggravation of existing or the creation of new transmission bottlenecks[6] (see e.g. [Zapreva 2000], [Brauner 2003]). A major reason for a possible overload of transmission capacities when transmissions take place over longer distances is the fact that reactive power can only be transported over shorter distances and has to be provided locally in the system. Similar conditions arise from the expansion of renewable electricity production in remote areas, e.g. offshore wind parks, where the grid is weak.

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4 As a consequence, the day-ahead scheduling of power plants is based on profit maximisation. Thus, especially in pool markets power plants are operated as profit centers.

5 An example for this is the case of England and Wales, where since the beginning of the liberalisation already in 1990 all investments have been exclusively into natural gas fired capacities [Bartsch et al. 2002].

6 It is argued that the (n-1) criterion for grid security could be compromised or violated. An overview of existing transmission bottlenecks in Europe can be found in [Haubrich et al. 2002].

2.2 Investment decisions and aspects of strategic planning

2.2.1 Investment needs in the European electricity sector

Numerous studies suggest that the currently existing European capacities for electricity generation will be significantly declining within the upcoming 20 to 30 years (see e.g. [VGB 2003], [UCTE 2000b, p. 120-159]). For the German electricity sector alone it is estimated that up to 50 GW of capacity will have to be replaced by 2020 [Pfaffenberger et al. 2004].

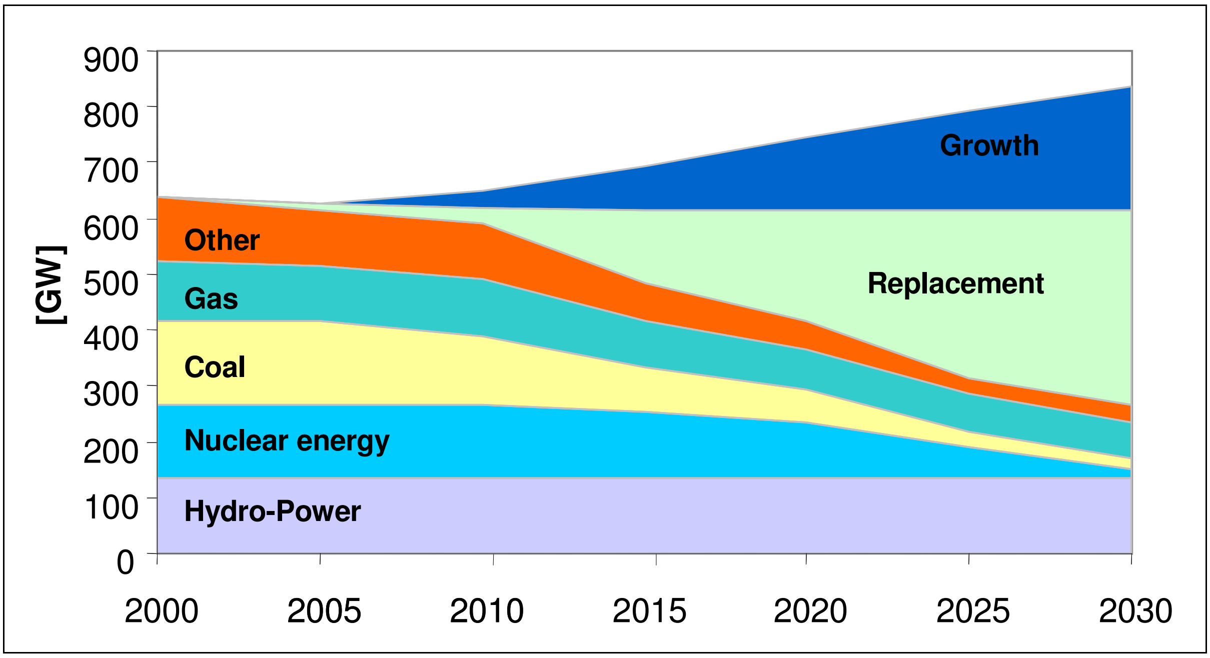

Figure 1: Power generation capacities in Europe by energy carrier [VGB 2003]

The recent years in the European power market have been characterised by overcapacities, with many units that have been in operation in excess of their economic lifetime. The power prices at the European energy exchanges (e.g. EEX, Nordpool) have thus largely been based on the marginal operational costs of those power plants and the construction of new capacities, both renewable and conventional, was not economic. However, with the electricity demand continuing to rise and the expectation of significant amounts of capacity to reach the end of their technical lifetime from 2010 onwards (see Figure 1), power prices have begun to reflect this reality with a tendency for prices to be based on full costs (e.g. [Ockenfels et al. 2005]). The construction of new power plants becomes economically attractive under these conditions, and in fact, a number of European utilities have begun to plan new capacities.

2.2.2 Specific characteristics of strategic planning in the electricity sector

It is the nature of strategic planning to anticipate upcoming changes of the relevant competitive environment of a company in order to develop adequate strategies that prepare the company for the expected changes. Thus, strategic planning with its essential relevance for the existence of a company in the long-term, is characterised by long-term planning horizons and high uncertainties. Also sector-specific influences play an important role. In the electricity and heat sector, investment planning and the strategic decisions of energy utilities are characterised by a number of peculiarities, which on the one hand result from the specific features of electricity and heat as products, and on the other hand from the properties of the technical infrastructure necessary to produce them (as given e.g. by [Hensing et al. 1998], [Wietschel 2000], [Göbelt 2001]). Compared to other sectors, investments in electricity sector installations are characterised by:

- Long technical service lifetimes (15 to 40 years for the majority of installations).
- High capital intensity and long payback periods.
- Interdependencies between investment decisions of individual actors due to the interlinking electricity grid.
- Strong political influence exerted on the sector.
- Numerous alternative types of installations with different technical, economic and environmental characteristics to be considered in an investment decision.
- Undesirable by-products, such as CO_2 and waste heat, ashes, slags, and flue gases caused by the conversion of fossil energy carriers into electricity.

In general, planning in the electricity sector has to take into account a number of further peculiarities, especially the characteristics of the products heat and electricity:

- Heat is pipeline-bound and electricity is grid-bound, requiring suitable networks for transport. Due to the immanent losses, transporting heat is economical only for short transport distances.
- Electricity and heat demand are characterised by daily and seasonal variations and are subject to strong stochastic influences.
- Large-scale storage of electricity is possible only to a limited extent and not directly, but only after conversion into other forms of energy[7].
- Given the limited possibilities for storage and in addition the high power quality requirements in terms of acceptable frequency and voltage levels in the grid, electricity generation and demand need to be temporally matched as exactly as possible. This necessity requires reserve capacities with different response times in order to balance short-term load changes in the time range of seconds and minutes.

System expansion planning aims at an energy supply infrastructure that is adequately structured and dimensioned to fulfil future supply tasks. Thus, decisions to invest into new generation capacities or to decommission existing units are central

[7] Most often mechanical energy forms are used for storage, as e.g. in pumped-storage plants or in underground compressed air energy storage facilities.

elements of this planning process. Due to the long technical service life and the long payback periods of capital-intensive energy sector assets, it is necessary to include changes in the framework conditions during their lifetime, necessitating dynamic investment planning methods over a long time horizon (e.g. 20 years or more). Moreover, as decisions for or against the deployment of technologies are strongly influenced by the expected utilisation of future power plant capacities, a strong interdependency exists between system expansion planning and production planning. In power production planning, an optimal production schedule tailored to the anticipated load profile is determined, which has to account for the different techno-economic characteristics of the different power plant types. As a general rule, energy system planning can be facilitated by the use of energy system models, which reproduce the existing supply system in mathematical (optimisation) models. Using such models allows a comprehensive assessment of alternative expansion scenarios, respecting the techno-economic characteristics and environmental constraints of the real energy supply system.

In the following sections of this chapter, the major factors of change in the framework conditions for strategic electricity sector planning as well as their implications for the strategic planning process shall be discussed.

2.2.2.1 Climate change policies

Concerns about the ecological and economic consequences of anthropogenously provoked climate change have made this topic one of the top issues in environmental politics and led to the formation of the United Nations Framework Convention on Climate Change (UNFCCC). It was established in 1992 during the so called Earth Summit in Rio de Janeiro and is aimed at a stabilisation of atmospheric greenhouse gas concentrations at a level that prevents a dangerous anthropogenous disturbance of the earth’s climate. Ratified by 154 states, the convention entered into force in March 1994, imposing specific mitigation obligations upon those parties to the contract listed in Annex I (the so called Annex I countries). The six greenhouse gases (GHG) comprised in the convention are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), fluorinated hydrocarbons (HFC), perfluorinated hydrocarbons (PFC, whereof especially CF_4 and C_2F_6) as well as sulphur hexafluoride (SF_6). The harmful effect of the substances is usually expressed in relation to that of CO_2 in terms of the so called global warming potential (GWP). With CO_2 accounting for 82% of the GWP-weighted GHG emissions of the European Union in the year 2000 [EEA 2002, p. 18], CO_2 is in the focus of climate change mitigation efforts.

The third Conference of the Parties to the Convention (CoP3) in Kyoto enacted the so called Kyoto Protocol [UNFCCC 1997] to substantiate the obligations of the industrialised countries by quantifiying individual reduction targets for GHG. Until the first commitment period between 2008 and 2012 an average reduction of 5.2% compared to the emission level of the Annex I countries in 1990 was stipulated.

Given the long-term nature of the climate change problem it is likely that the relevant time frame for GHG mitigation will consecutively need to be extended with increasingly tighter obligations[8].

Three options for international cooperation (the so called Flexibility Mechanisms) are provided in the Kyoto Protocol, which allow to trade emission rights or emission reductions in order to allow for a cost-optimised target compliance of Annex-I-countries[9]. All three Kyoto mechanisms allow for a geographically flexible fulfillment of national reduction obligations. Within the framework of the project-based mechanisms Joint Implementation (JI) and the Clean Development Mechanism (CDM) emission reductions realised in a host country can be credited to the investing Annex-I-country. Moreover, an international trade with GHG emission rights is foreseen.

The project-based Kyoto mechanisms serve a dual purpose. On the one hand, they can contribute to a reduction of the overall costs of compliance with the Kyoto Protocol targets, which will be a benefit for industrialised countries. On the other hand, they can help to support sustainable development objectives in the host countries. While the political discussion process is still ongoing, a number of conceptual, methodological and regulatory issues related to JI and CDM projects have already been or are currently being resolved, including the controversial and complicated issue of appropriate baseline methodologies for the accounting of GHG emission reductions achieved through the project[10].

Another option allowed in the Kyoto Protocol is the specification of targets for a group of countries, a so called bubble, instead of individual national targets. Making use of this flexibility option of the Kyoto Protocol the EU-15 as an entity has commited itself to a reduction of 8%[11]. In the so called Burden Sharing agreement the contributions of each Member State to this target are laid down, with Germany obliged to reduce 21% of its 1990 emission levels.

The EU Commission has adopted the concept of emission trading and made it mandatory for all Member States in its Directive 2003/87/EC [EC 2003b]. This

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8 An emission reduction target beyond the first commitment period of the Kyoto Protocol has already been specified by the Enquete Commission of the German Federal Government, which aims to achieve a 40% reduction by the year 2020 [Enquete 2002].

9 The rationale for emission trading is to avoid emissions where the reduction is cheapest. In order to be economically justified, the efficiency gains induced by this instrument must be greater than the transaction costs associated with the trading scheme.

10 The process of defining standardised and generally accepted accounting procedures for the achieved emission reductions from JI and CDM projects with low transaction costs (cf. e.g. [Michaelowa et al. 2003], [Rentz et al. 2003]) has for a long time been a critical issue. When standardised methodologies are lacking, project investors are confronted with uncertainties about whether and how many emission reductions from their projects will be recognised. In this context, also model-based approaches have been proposed for the electricity sector (cf. [Rosen et al. 2004]). An overview of the currently approved calculation methodologies and guidelines can be found on www.unfccc.org.

11 Taking into account average economic growth rates, this commitment corresponds to a real reduction of about 13% to 14%.

approach was implemented independently from the entering into force of the Kyoto Protocol, which did not take place before February 16 in 2005, but was from its beginning intended to be coupled to the global emission trading option specified in the Kyoto Protocol. Contrary to the Kyoto Protocol emission trading approach, which allows for an emission trade among nations, the EU Emission Trading Scheme is implemented with companies as actors. Emission rights are assigned to individual production units and are defined in the so called National Allocation Plans (NAP). For the first trading period from 2005 to 2007 these plans were due to be published by each Member State until March 31, 2004. An overview of NAPs for 2005-2007 as well as those for the first commitment period from 2008 until 2012, is compiled on a special website of the EU[12]. This rationing of the production factor CO_2 emission rights, as opposed to the formerly freely available right for unlimited emissions, is inducing significant changes into the business of energy and emission intensive companies. As an inevitable consequence of its scarcity, a price evolves for this resource, which since has to be managed as a new production factor.

Thus, the politically induced shortage of the formerly freely available production factor results in additional requirements of utilities for extended analyses, not only of the power and fuel markets, but also of the CO_2 emission certificate market. For all areas of its business, a company needs to assess how the rationing of emission allowances as a new production factor influences the strategic business environment and business activities. This is of special importance with regard to the financial consequences resulting from the necessary compliance with reduction obligations, i.e. whether the obligations should be fulfilled through own mitigation activities or by purchasing emission certificates. In this context the future certificate price development is essential, as it needs to be taken into account as a cost factor in the assessment of existing installations as well as for replacements or additional investments.

For a detailed description and an extensive theoretical assessment of the changed framework resulting from the rationing of CO_2 emissions and the resulting practical implications for production planning see [Enzensberger 2003] and [Fichtner 2004]. In general, the certificate price and its development can be interpreted as a price signal for companies helping them to decide whether own investments into emission

[12] http://ec.europa.eu/environment/climat/emission_plans.htm

mitigation should be realised [Cames et al. 2001, p.26][13]. In Figure 2 the development of prices for emission allowances at the European Energy Exchange in Leipzig from October 2005 until May 2006 is sketched[14].

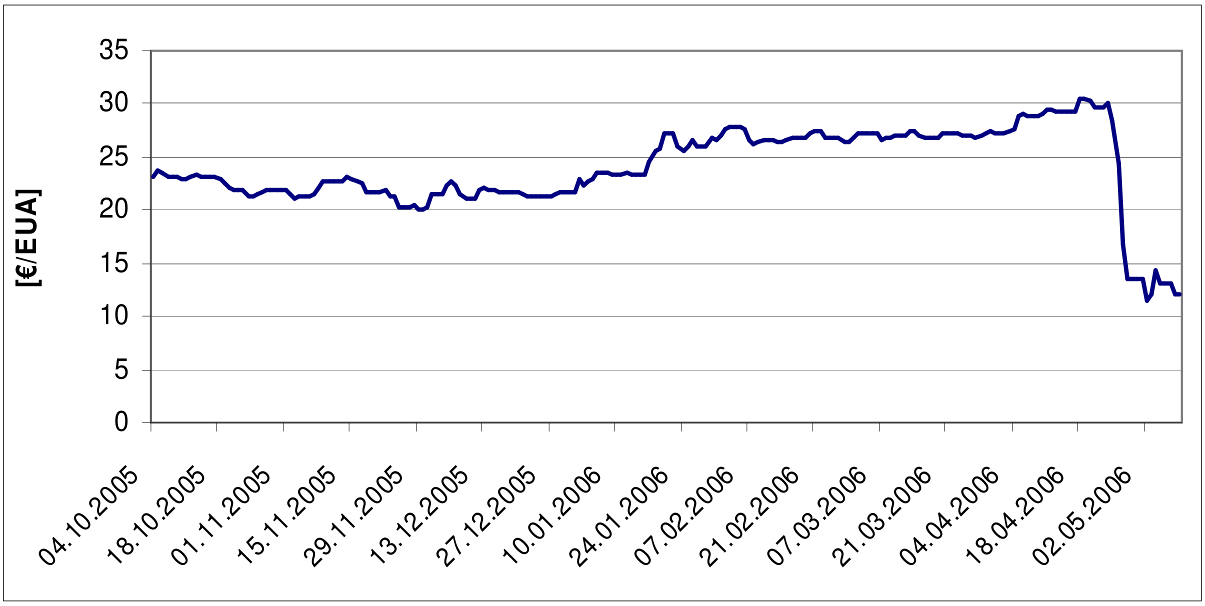

Figure 2: Evolution of prices for CO_2 forwards at the EEX [EEX 2006]

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[13] Concerning the most important technical CO_2 mitigation options in power and heat generation, [Rentz et al. 1995] and [Fichtner 1999, p. 9] differentiate among the following groups:

- Efficiency increase: By increasing the efficiency of existing installations lower specific emissions are achieved.
- Fuel-switch: Substituting fuels with a high carbon content (related to the fuel's heating value) by less emission intensive fuels can also achieve emission reductions. A common example is the fuel switch from oil to gas.
- Load shifting in production planning: With existing overcapacities and the (technically restricted) variability of the load ranges that power plants can operate in, less emission intensive technologies can be utilised more intensively than more emission intensive ones.
- Capacity replacement: Substituting existing old units by more efficient power plants contributes effectively to the reduction of emissions, however, at high capital costs.
- Expansion of renewable electricity use or nuclear power: An expansion of these CO_2 neutral technologies reduces overall emissions by substituting CO_2 intensive generation.
- Increased use of combined heat and power technology: The utilisation of waste heat from power production to substitute heat generation in separate boilers reduces emissions by an increased utilisation of the fuel's energy content.
- Technologies for CO_2 capture and storage: A separation of CO_2 from flue gases and a subsequent liquefaction in order to store the CO_2 is possible with existing technology. However, the application of this emission reduction alternative is impeded by comparatively high costs.

[14] Compared to experiences with regional or company wide emission trading schemes (see e.g. [Betz et al. 2003, p.29]), prices started out at a high level and kept rising up to more than 30 €/t CO_2. However, when in April of 2006 it became clear that sufficient allowances had been available for the obliged actors in the first year of emission trading, prices dropped sharply by more than 50%. Nevertheless, the remaining price level is still comparatively high, especially when compared to emission reductions procured from prospective JI and CDM projects, e.g. in the ERUPT and CERUPT tenders of the Dutch government at average prices of 4.78 and 4.7 €/t CO_2, respectively (see [JIN 2002, p. 10] and [JIN 2003, p. 2]). For a comprehensive overview of emission reduction costs and certificate prices (as the result of both model calculations and actual trading schemes), reference is made to [Fichtner 2004, p. 78-82].

Currently, the energy supply sector is the biggest emitter of CO_2 and contributes with about 27% to the total CO_2 emissions in the EU [EEA 2002]. The majority of emissions in this sector are released from fossil fuels converted in plants generating heat and/or electricity. For different reasons this sector is of special importance for the implementation of effective emission reduction measures. First of all, the mitigation options within the energy sector have been found to be relatively cheap in comparison with other emitting sectors (cf. e.g. [IPTS 2000] and [Mantzos et al. 2003]). Furthermore, the structure of the sector with a relatively small number of large emitters and producers facilitates the accounting and monitoring of emissions.

In Directive 2004/101/EC, the so called 'Linking Directive' adopted on 27 October 2004 [EC 2004a] the European Commission defines the rules for an integration of emission reductions from actions under the Flexibility Mechanisms into the European emission trading scheme[15]. From 2008 onwards credits from JI and CDM projects can be recognised as equivalents to EU emission allowances. The principles for the acknowledgement of credits are in accordance with the rules of the Kyoto Protocol, i.e. CERs generated from CDM projects before 2008 can be recognised for the first commitment period from 2008 to 2012, while emission reductions from JI projects before 2008 will not be counted at all.

2.2.2.2 Supply of energy carriers

The situation regarding EU primary energy demand and electricity demand can briefly be characterised as follows. The growth of EU primary energy demand projected in the EU Green Paper *'Towards a European strategy for the security of energy supply'* [EC 2000a] is 11% from 1998 to 2030 and an increase of the energy dependency from 49% to 71% is expected in the same time period (baseline scenario). Regarding the use and supply of resources for electricity generation the situation in the EU is characterised by the following observations:

Resources of oil and gas are limited and exploitation is mostly expensive. Even a possible accession of Norway with its significant oil and gas reserves could not ameliorate this situation beyond a certain extent. While the availability of solid fuels (especially coal) in the EU is much better, their extraction is not competitive compared to the costs from external suppliers[16]. Moreover, several Member States

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[15] Each country, in its national allocation plan, can define a percentage of allowances to each installation, up to which CERs and ERUs from project activities can be used in the Community ETS.

[16] In many European countries the mining of hard coal is a highly unprofitable industrial branch. Many unprofitable mines have been closed in recent years. However, due to the vital importance of the mining industry for the regional economic structures mines have not been closed immediately, but instead a process of structural adaptation has been introduced and financed by state aids. An example is the Polish mining industry, where 147,000 workers were employed in 2001, despite a high overall deficit of the sector (see [Gruß et al. 2002, p. 62]). Germany is an example for a country, where this process has entered an advanced stage. In 1997 state aids were significantly reduced by law ('Steinkohlebeihilfegesetz') and the remaining coal mining activities of the German mining companies have been pooled in the 'Deutsche Steinkohle AG' (see [Brabeck et al. 1999] and [Hufschmied 2002]).

have declared or are already pursuing a phase-out of nuclear capacities, which is likely to aggravate the dependency on energy sources outside of the EU. With this in mind, it is obvious why the security of energy supply is one of the three general EU policy objectives that are of crucial relevance to energy policy design, namely:

- overall competitiveness,
- security of energy supply, and
- environmental protection.

In the EU Energy White Paper[17] (p.13) it is stressed that ‘energy policy must aim, wherever possible, to reconcile these objectives while being consistent. […] A future priority will be to ensure that in the long-term perspective the consistency of the Community energy actions is maintained and, where possible, strengthened’.

It is also the underlying concern of the Green Paper on energy supply security, which identifies as main points:

- An increasing dependency on external sources of energy supply. The accession of the new Member States does not provide relief for this situation.
- The influence of the EU on the general energy supply condition is limited, however, on the demand side an intervention is possible by promoting energy savings measures in the built environment and transport.
- The EU is presently not in a position to respond to climate change and meet its commitments from the Kyoto Protocol.

Besides controlling the growth of demand, the Green Paper on energy supply security mentions managing of the supply dependence as a key policy priority. In this context, among others, a strong stimulation of new renewable sources as well as the strengthening of electricity transmission networks between the Member States are suggested.

When judging the relief that indigenous renewable electricity generation can provide to the security of supply in the fossil energy sector one should bear in mind that the security of supply can not be completely neglected either for some renewable sources of electricity. While the security of supply of conventional fuels is crucially influenced by the available total resources[18], price volatility and geopolitical or geostrategic interests, RES-E supply security is generally much higher due to the

[17] European Commission: Energy for the future: renewable sources of energy - White Paper for a community strategy and action plan, European Commission, 1997.

[18] Based on model calculations up to the year 2050, [Raskin et al. 1998] estimate that the current oil reserves could reach up to the year 2025, while the proven natural gas reserves in a business as usual scenario are expected to be depleted in 2035. Until 2050, an estimated 60% of the additionally developed reserves is used. A number of different studies (e.g. [IEA 2002b], [Mantzos et al. 2003], [IEA 2004a] and [Prognos/EWI 2005]) make estimations of the future availabilities of and demand for fossil energy carriers. A thorough overview of such studies and assessments is found in [Ball 2006]. Even if the results of these studies show significant differences, they demonstrate the necessity to tap new and especially renewable resources of energy.

indigenous availability of the sources without large price variations. However, (some) renewable energy carriers show annual and seasonal (e.g. hydro) or even daily to hourly variations of availability (wind, photovoltaics). The fluctuating availability of wind can usually be compensated, e.g. by pumped storage, but it also influences conventional generation to a certain degree, which has to provide reserve capacities and control power. These short-term effects of wind power fluctuations become relevant at high penetration rates as e.g. in some regions of Northern Germany. Also long-term variation phenomena exist (e.g. wind years with a higher or lower overall energy yield). These variations are caused by climatic effects, e.g. years characterised by very hot summers and long periods of high pressure influence with very calm wind conditions. Similar effects apply to hydro power, where the annual precipitation can cause variations in reservoir stocks and thus affect the availability of hydropower. However, significant shares of the additional renewable sources expected to be added in the EU-25 until 2010 (solid biomass, biogas, biowastes) are independent of larger variations as they can be stored, which homogenises their availability. Thus, they show the most beneficial characteristics with regard to the security of supply. The same applies to other RES with a constant or nearly constant availability, as e.g. geothermal energy.

2.2.2.3 Use of nuclear power

With a gross production share of 33% in 2002 the use of nuclear energy is one of the most important technologies for base load power generation in Europe [Eurostat 2004]. With 78% of its gross annual power generation in 2002, corresponding to 436.8 TWh [Eurostat 2004], France is the European country relying most on the use of nuclear power. For comparison, Germany covers only about one third of its power demand by nuclear capacities in total, but the shares vary widely from one Federal State to the next - between zero and shares comparable to those in France.

Other countries making use of significant amounts of nuclear power are Spain, Sweden, and the UK. Further, nuclear facilities with lower cumulated capacities are operated in Belgium, the Netherlands, Finland, and Switzerland. Nuclear power is a typical base load technology[19], with about 70% of base load generation across Europe relying on nuclear energy, it takes an important role in European electricity supply. However, its current use and especially its future role are heavily disputed. Time and again it is the subject of lively political discussions about its future importance in the electricity mix in most European countries. Under the given pricing schemes its use is economically advantageous and the power generation is practically CO_2 free. On the downside, security risks in plant operation and the necessary long-term storage of spent nuclear fuel are the most important arguments.

[19] Noteworthy variations of plant output are only known from France, where the high share of nuclear generation requires that nuclear capacities are also regulated up and down in intermediate load (see e.g. [IEA 2001, p. 105 f.]).

Due to the extremely limited uranium reserves in Europe and the unavoidable losses in the nuclear fuel cycle, existing nuclear power technologies can contribute to the security of supply only in a restricted sense. However, different from fossil fuel imports, which often come from countries with unstable political conditions, major uranium reserves are located in politically more stable countries like Australia and Canada. From 2015 onwards new reactor lines are envisaged to be commercially tested in the so-called ‘Generation IV’ roadmap (cf. [Schulenberg et al. 2004]). These improved nuclear generation technologies are not only expected to be safer, but also more efficient in terms of fuel use and the recycling of wastes than present processes.

The EU Green Paper comes to ambivalent conclusions concerning the use of nuclear energy. While acknowledging its contribution to a more secure and less emission intensive power supply, it also concludes that the use of nuclear power can be regarded as a long-term solution for European electricity only if the hitherto unsolved problem of radioactive waste disposal can be solved satisfactorily. However, it also calls for a continued European leadership in the civil use of nuclear energy to secure the existing technological knowledge in this field.

Governments across the EU Member States are discordant in their views on the future use of nuclear energy. Especially France will further rely on nuclear power as an important pillar of its electricity system[20], and also Finland has begun to construct a new reactor[21]. Similarly, Great Britain and Switzerland have announced to keep the option of a future use of nuclear energy open. The other five EU countries currently using nuclear power (Belgium, Germany, the Netherlands, Spain, and Sweden), either have already decided on a moratorium or have announced to agree on one [Taylor 2002, p.2].

In Germany, the decision to phase out nuclear capacities was made official in an agreement between the Federal Government and the energy utilities on June 14th in 2000 [BMU 2000b]. The agreement rules out the construction of new nuclear capacities and furthermore restricts the electricity that may be produced by the existing ones to an amount of 2623.3 TWh from the beginning of the year 2000 onwards. Due to their low variable costs the capacities to be decommissioned delivered an essential contribution to the coverage of base load in Germany. Thus, from a purely energy economic point of view, the phase-out decision can be challenged, especially with regard to greenhouse gas reduction strategies and the power plant alternatives favoured under the conditions of the liberalised market[22]. Usually, these are capacities with short payback periods like gas fired combined-

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[20] The construction of the first French EPR is scheduled to take place between 2007 and 2012 in Flamanville [Areva 2006].

[21] In addition to the four existing nuclear power plants, a 1600 MW EPR is under construction in Olkiluoto since 2005.

[22] Although politically disputed and challenged as economically inefficient (see e.g. [Lindenberger et al. 2005]), the agreement has not been touched by the newly elected German government.

cycle power plants, characterised by a comparatively high share of variable costs, which makes them most suitable for the coverage of peak load. A higher share of combined-cycle power plants, operated for longer hours per year, especially in combination with higher gas prices, may lead to higher costs for energy supply and thus also increasing power prices.

2.2.2.4 Renewable energy sources

Sparked by the national targets defined in Directive 2001/77/EC, the utilisation of renewable energy carriers for electricity generation is on the rise in the Member States of the EU. As the most prominent example, an overall installed capacity of 15.327 MW of wind turbines was reached in Germany in 2004, capable of producing roughly 30 TWh/a of electricity [BWE 2005b]. The growth of this technology has been mostly due to the feed-in tariffs granted in the framework of the regulations of the renewable electricity act EEG (Erneuerbare Energien Gesetz, [EEG 2000]) and its amendment in 2004 [EEG 2004]. With an overall target of 21.6% of electricity from renewable sources in 2010, the Member States have commited themselves to reach individual national targets. Owing largely to the degree of freedom allowed in the design of national renewable electricity promotion schemes, Member States have been unequally successful on their way to achieve these targets up to now. Although a harmonisation of these schemes is envisaged, it is not likely to happen in the near future. However, it can be expected that renewable electricity, which is mostly not generated by utilities but by independent power producers, will reach higher market shares, limiting the possible market volume to be served by conventional utilities.

The further development of power generation technologies based on renewable sources of electricity initiated already is generally regarded as a step towards sustainability within the energy sector (e.g. [BMU 2000a], [EC 2000b], [Dreher 2001], [Fleury 2005]). Utilising renewable energies contributes among others to the protection of natural resources and to climate protection, but also reduces dependencies on imported fossil and nuclear fuels. Although no longer term targets have been specified officially at the time of writing, discussions are going on about this issue in order to create a better security for renewable energy investors[23].

Historically, the development of renewable electricity installations has been the domain of small and medium scale investors. Up to now, utilities were usually not interested in this market due to the comparatively small dimensions and too low profit expectations from the projects, even though a growing number of independent power producers leads to a decrease in the possible electricity sales for the utilities. However, with growing project sizes, and especially in the offshore wind sector, where large investments are necessary to develop the sites, utilities have started to invest in this market as well.

[23] A share of 20% of primary energy (corresponding to 33% of electricity) from renewable sources by 2020 has been suggested [EREC 2005b].

Only a small introduction to the significance of renewable electricity in the changing general framework conditions of the European electricity market has been given here. As the utilisation of renewable electricity is the core topic of this work, the relevant background concerning renewable energy technology development, the political drivers behind this process as well as the consequences of its growing importance, e.g. the interactions with the electricity system infrastructure and the challenges for conventional generators, shall be further elaborated in the following two chapters.

3 Renewable electricity generation in Europe

3.1 Utilisation of renewable energy sources

Energy carrier resources can in principle be subdivided into exhaustible resources on the one hand, and non-exhaustible, or renewable resources, on the other hand. Exhaustible energy carrier resources are characterised by a limited availability, as the resource base is diminished[24] when the energy carriers are utilised in energy conversion processes[25]. This is the case mainly for fossil energy carriers as coal, oil, or gas. Contrarily, renewable energy carriers are characterised as being practically indepletable within human time dimensions.

Renewable energy resources that can be exploited for electricity generation can be differentiated into six major groups. In the following, these groups are introduced along with a short description of their status in terms of utilisation and available potentials. Electrical power produced from these renewable energy sources (also referred to as RES) is designated as renewable electricity or electricity from renewable sources, or RES-E.

Hydropower: Electricity production from hydraulic resources is already well developed and represents the most important source of renewable electricity production in the EU-15 so far. This category is separated into small hydropower plants with less than 10 MW installed power capacity and large ones with more than 10 MW.

Wind power: Having reached a significant share of the electricity production in several European countries (e.g. Denmark, Germany, and Spain), wind energy is the most promising source for the mid-term future. While on-shore wind power generation has reached a considerable degree of technological maturity, further research needs to be undertaken and experiences made with off-shore installations, especially in deeper waters [Hirschhausen et al. 2005].

Biomass and biogas: Biomass fuels include solid biomass, such as energy crops, wood fuels, forestry wastes, solid industrial by-products (bark, waste from sawmills, wood and paper industry production), solid agricultural wastes (straw, poultry litter), and wood waste. Fuel sources for the production of biogas are farm slurries, usable agricultural residues (e.g. from sugar beet production), and residues from pasture and separated biodegradable fractions of municipal wastes. Sewage gas and landfill gas also belong to this category. From an economic point-of-view, the use of biomass either as a solid fuel or as a gas is interesting with electricity costs in a comparable range as for wind energy.

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[24] In special cases this can also be the case for resources that are counted as renewable. An example is the case of geothermal energy, where the heat reservoir actually is depleted, but to a negligible extent when compared to the total size of the potential.

[25] While energy carrier resources can be consumed or utilised, the energy as such, which is contained in the energy carrier, is not used, but only converted to different forms of energy.

Solar power: While offering a combined realisable potential (photovoltaics plus solar thermal) comparable to that of hydropower, electricity from solar power, and especially photovoltaics, is a rather expensive source of electricity production. Solar thermal technologies normally offer a more economical way of electricity production than photovoltaics. However, they can only make use of direct sunlight, while photovoltaics can also exploit diffuse light.

Wave and tidal energy: With very few realised installations these represent two energy resources at the beginning of their technical development. The biggest tidal power plant with 240 MW is operating in Saint Malo, France, while different wave power plant concepts are currently undergoing experimental evaluations.

Geothermal energy: Geothermal energy is mainly used for heat generation, but also for electricity production at some locations, usually in cogeneration plants. Recent studies indicate an enormous potential for electricity production, especially in Germany.

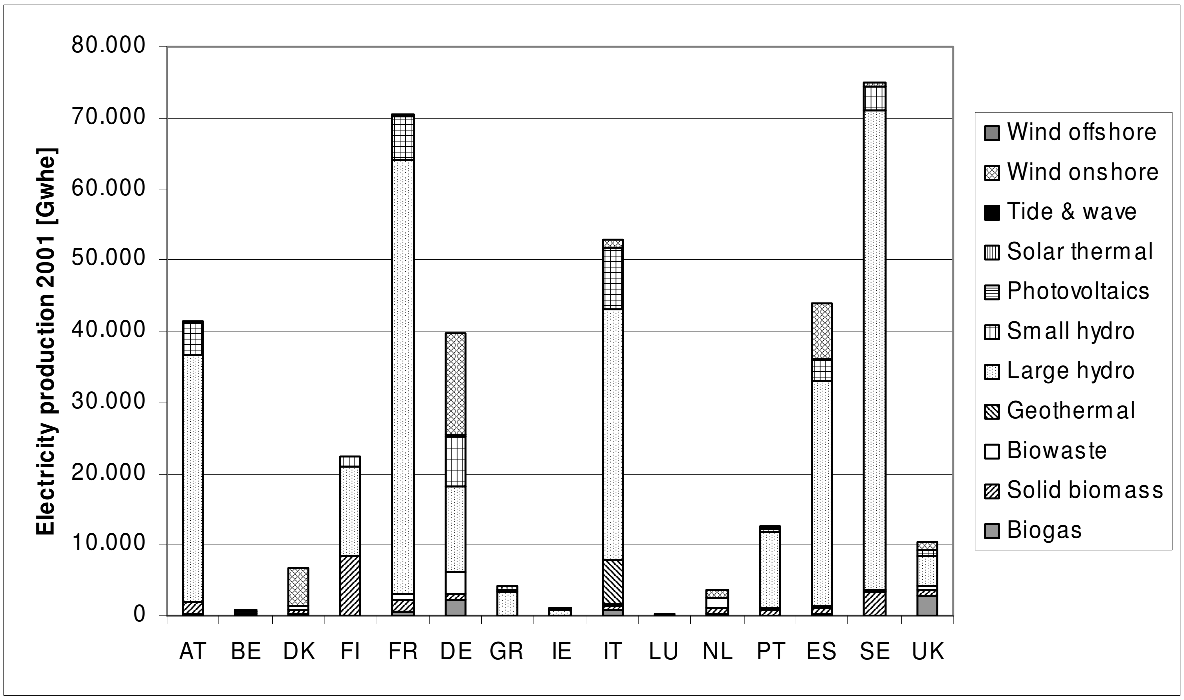

Figure 3: RES-E production in the EU-15 in 2001 [Ragwitz et al. 2005]

An overview of the contribution of the different energy carriers to the renewable electricity production in the EU-15 countries is given in Figure 3. In combination with Figure 4, which shows the shares of the above technologies related to the total renewable electricity generation in the EU-15 in the year 2002 it makes obvious that the most intensively used renewable electricity source is hydro power, with more than three quarters of total renewable power produced. The remaining quarter is mainly made up of a (growing) share of wind as well as renewable power from biogenic sources, while geothermal, solarthermal and photovoltaics only contribute marginally.

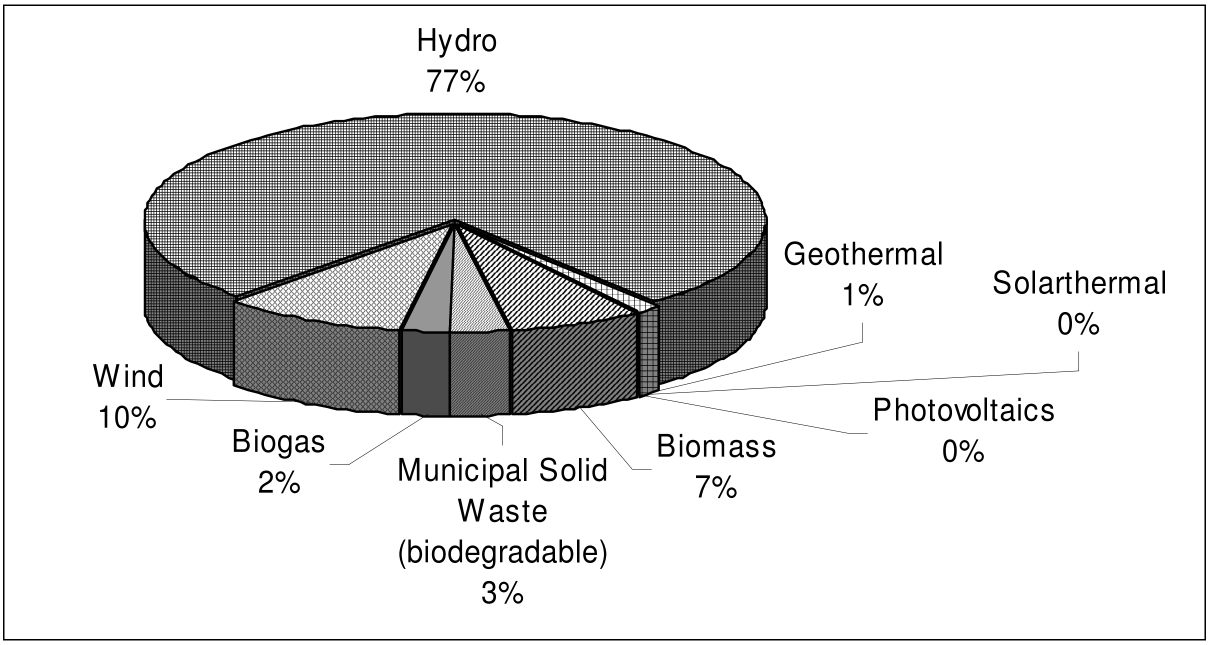

Figure 4: Contribution of different renewable energy carriers to gross renewable power production in the EU-15 in 2002 [IEA 2004b]

Table 1: Development of renewable electricity production and share of total consumption in Europe [Eurostat 2005]

	1990		1997		2003	
Country	**GWh**	**% of con-sumption**	**GWh**	**% of con-sumption**	**GWh**	**% of con-sumption**
AT	32,575	65.4	37,692	67.2	38,466	55.9
BE	0,766	1.1	0,862	1.0	1,674	1.8
DK	0,778	2.4	3,279	8.8	8,745	23.2
FI	15,888	24.4	19,402	25.3	19,384	21.8
FR	55,543	14.8	66,861	15.2	65,098	13.0
DE	19,441	4.3	23,796	4.3	47,248	7.9
GR	1,770	5.0	3,919	8.6	5,787	9.6
IE	0,697	4.8	0,755	3.8	1,138	4.3
IT	35,016	13.9	46,461	16.0	44,045	12.8
LU	0,113	2.1	0,129	2.0	0,169	2.3
NL	1,156	1.4	3,478	3.5	5,331	4.7
PT	9,851	34.5	14,229	38.3	18,089	36.4
ES	26,015	17.2	36,869	19.7	58,818	22.3
SE	74,632	51.4	72,053	49.1	59,414	40.0
UK	5,762	1.7	7,042	1.9	11,234	2.8
EU-15	***280,003***	***13.4***	***336,83***	***13.8***	***384,64***	***13.7***
EU-25	***293,274***	***12.2***	***352,37***	***12.8***	***398,60***	***12.8***

The utilisation of renewable energy sources for electricity generation in the individual EU-15 Member States for different years is shown in Table 1. While in general a tendency to use more renewable electricity can be perceived, the share in relation to total electricity consumption remained more or less the same from 1990 to 2003 due to a continuously rising electricity demand. Mostly due to the geographically inhomogenous availability of renewable energy carriers, the amounts of renewable electricity generated differ widely from Member State to Member State. In Scandinavia and the Alpine region with abundant hydro power resources and low population densities, as e.g. in Sweden or Austria, the highest shares of renewable electricity utilisation are found. In countries like the Netherlands, which are densely populated and have a flat topography, the utilisation of renewable electricity is limited.

3.2 Rationale for increasing the utilisation of renewable energies

With the exception of large scale hydro power, and not taking into account any financial incentives, only a limited amount of renewable resources is currently interesting to be utilised for electricity generation from a purely economic point of view. However, numerous benefits are associated with the use of RES-E, which either are hard to be directly evaluated in economic terms, or which at least are not reflected in today's electricity prices. These benefits include (adapted from [Resch et al. 2005, p.1]):

- nearly no GHG emissions;
- reduction of further pollutants (other than CO_2) associated with electricity services;
- reduced dependency on energy carrier imports;
- diversification of the resource base;
- avoided risks of disruption in fossil fuel supply and hedge against associated fossil fuel price instabilities;
- provision of infrastructure and economic flexibility.

Due to the economic, ecological and social benefits, the use of renewable energy carriers is generally regarded as a contribution towards a sustainable electricity supply (c.f. [BMU 2000a] and [EC 2000b]). As an in-depth description of the sustainability concept[26], its general practical applicability and its operationalisation in the energy sector would be out of scope of this thesis, reference is instead made to relevant literature in this thematic field, e.g. [Fleury 2005], [Hohmeyer et al. 1991], [Kopfmüller 2000] and [Rentz et al. 2001]. Nevertheless, external effects and the issue of energy supply security, which both are important sustainability-related

[26] The commonly accepted definition of sustainable development was coined by the Brundtland-Commission: 'Sustainable development meets the needs of the present without compromising the ability of future generations to meet their own needs.' [Brundtland et al. 1987, p. 43]. This definition is to be understood as a 'regulative idea' [Kopfmüller 2000], for which tangible ways of realisation and concrete aims need to be formulated. Instruments and measures applicable in energy policy are described and evaluated in [Rentz et al. 2001].

aspects in the context of energy utilisation, shall shortly be drafted and discussed in the following sections, along with a set of general requirements for a future, sustainable energy system.

3.2.1 External effects and related costs

The need to satisfy the increasing EU energy demand brings along a number of energy-related environmental impacts. Renewable and conventional power generation technologies alike affect the environment and the socio-economic system. In the case of fossil fuels these impacts are mainly caused by power plant emissions, either locally, as in the case of NO_x and SO_x, or globally, as in the case of CO_2. To cope with the resulting consequences, the EU has adopted primary policy objectives concerning this issue: Environmental protection is stated as one of the most relevant objectives in the design of the community's energy policy (cf. the EC Green Paper [EC 2000b]).

While CO_2 emissions from fossil power production are critical due to their global warming potential, the impacts of NO_x and SO_x are based on their transformation into acidic substances in the atmosphere[27]. These are subsequently washed out with precipitation as acid rain, which causes considerable damage, among others to the built environment, to plants, and to the soil. In contrast to CO_2 and other greenhouse gases, NO_x and SO_x emissions do not spread in the atmosphere on a global scale, but they are responsible for local or regional effects close to their emission sources. Thus, the reduction of NO_x and SO_x shows direct benefits close to where the reduction takes place[28].

Besides the emissions of CO_2, SO_x, and NO_x a number of harder to quantify environmental and socio-economic impacts are caused by both conventional and renewable electricity generation technologies. These "external effects" and impacts have been the subject of extensive research efforts during the last 10 to 15 years. The most important contribution to mention in this context is the EU funded research study 'ExternE' (Externalities of Energy)[29], which was conducted to quantify the social and environmental costs of electricity production.

Although difficult to quantify, all effects that are incurred can theoretically be assigned an economic value, i.e. a benefit in the case of a positive effect, and a damage or cost in the negative case. Positive and negative consequences are both called external effects. However, only external costs shall be treated in this chapter.

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[27] In 2001, CO_2, NO_x and SO_x emissions by large combustion plants in the EU-15 each accounted for around one third of the total emissions from installations under the Integrated Pollution Prevention and Control (IPPC) Directive 96/61/EC (cf. [EC 2005c]).

[28] Contrary to the globally effective greenhouse gases, it is thus not wise to introduce an international trading scheme for NO_x and SO_x. Instead, national emission ceilings have been established in the so called NEC-Directive 2001/81/EC [EC 2001b].

[29] Details can be found at http://www.externe.info. While this study has been criticised for its shortcomings, especially in the evaluation of nuclear energy, it presents a comprehensive approach to monetarise social and environmental impacts of each generation technology.

External costs are interferences or damages, that are provoked by a certain activity and inflicted upon a third party - usually the general public - which does not receive compensation by the originator[30]. In Table 2 an example of the study results for Germany is given. It contains the external costs incurred in different categories by the use of different conventional and renewable energy carriers.

Table 2: Marginal external costs of electricity production in Germany [EC 2003d][31]

	Coal	Lignite	Gas	Nuclear	PV	Wind	Hydro
Damage costs [cent/kWh]							
Noise	0.000	0.000	0.000	0.000	0.000	0.005	0.000
Health	0.730	0.990	0.340	0.170	0.450	0.072	0.051
Material	0.015	0.020	0.007	0.002	0.012	0.002	0.001
Crops	0.000	0.000	0.000	0.001	0.000	0.001	0.000
Total	0.750	1.010	0.350	0.170	0.460	0.080	0.050
Avoidance costs [cent/kWh]							
Ecosystems	0.200	0.780	0.040	0.050	0.040	0.040	0.030
Global Warming	1.600	2.000	0.730	0.030	0.330	0.040	0.030

Both the damage costs and the avoidance costs of fossil fuels are significantly higher than those of renewable energy sources. While the external costs determined for nuclear power show external costs comparable to those of renewable electricity sources, the risks connected to this technology in terms of accidents and the unknown consequences of long term storage of radioactive wastes are not reflected in the given values. Different solutions can be applied to achieve an internalisation of external costs[32]. With the start of the EU Emissions Trading Scheme (EU ETS) in 2005, the internalisation of parts of these external costs has begun. However, since a complete internalisation of all relevant external costs does at present not appear to be a (politically) realistic alternative, it is argued that the financial promotion of RES to account for their lower emissions profile might be justified for reasons of overall (macro-)economic efficiency (see e.g. [Menanteau et al. 2003]).

3.2.2 Security of supply

As already mentioned in section 2.2.2.2 the growth of EU primary energy demand projected in the Green Paper is likely to cause an increase of the energy dependency

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30 For a definition of the term external costs also refer to e.g. [EC 1995], [Friedrich et al. 1997], [Fleury 2005], or [Hohmeyer et al. 1991].

31 Median estimates for current technologies; CO_2 emissions are valued with avoidance costs of € 19 per ton of CO_2.

32 The term internalisation of external costs generally refers to measures that are suitable to reduce external effects to a macroeconomically desirable level. This level can be determined by a cost-benefit analysis. An internalisation of external costs is aimed at the consideration of external costs in the decision-making process of economic actors in order to prevent a macroeconomically misarranged allocation of resources. For the best overall efficiency, external costs should be allocated to their originators (see [Friedrich et al. 1997]).

from 49% to 71% in the baseline scenario. By replacing primary energy carriers[33], and preferably the use of imported energy carriers, renewable energy sources are able to contribute to a reduction of energy carrier import dependency. Own calculations based on the European Energy Outlook [Mantzos et al. 2003] and the 'Policy Scenario' of the FORRES study [Ragwitz et al. 2005] have shown that boosting the use of RES-E in the EU-25 can yield significant benefits in this respect. Compared to the baseline scenario, about two thirds of the expected increase in import dependency can be avoided by the use of RES-E. When the 'Energy efficiency plus high renewables' scenario of the European Energy Outlook is regarded, the expected increase in import dependency for the EU-25 is lower and can almost completely be equalised by the development of RES-E. Thus, the combination of ambitious RES-E development with energy efficiency measures would be able to achieve a significantly reduced increase in the EU-25 import dependency [Rentz et al. 2005a].

An important complementary approach to achieve higher RES-E shares and an improved security of supply situation is increasing energy efficiency. This may be achieved by promoting the decrease of total electricity consumption through legislation and programmes aiming at energy savings, as already implemented in Germany, in France[34], and in several other countries. It can be noted that in Denmark, where the RES-E contribution has been extraordinarily high, the increase in electricity consumption has been rather constrained since 1997. This is of importance as the growth of RES-E is in most cases not sufficient to equalise the demand increase. Then the overall electricity consumption rise leads to an increase of power generation from conventional sources, including those that have to be imported. The EU Commission has taken steps into this direction and established energy efficiency targets for the Member States. In the Energy End-Use Efficiency and Energy Services Directive 2006/32/EC [EC 2003b], an indicative energy savings target of at least 9% for all Member States to be achieved within 9 years, i.e. corresponding to an average savings target of 1% per year between 2006 and 2012[35].

An integrative political strategy to guarantee a secure, competitive and sustainable energy supply for Europe is proposed by the European Commission in a new Green Paper [EC 2006]. This strategy also includes proposals for a renewable energy road map and an action plan on energy efficiency.

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[33] Two approaches exist to calculate the amount of primary energy saved by renewable energies. In international statistics the total electricity value is usually applied, which assigns an efficiency of 100% to energy carriers without a heating value (e.g. hydro power, wind power, or photovoltaics, see [BMU, 2005]). Contrarily, the total heat vaule uses the average fuel utilisation efficiency of conventional power plants to determine the primary energy equivalent of renewable electricity, which consequently leads to higher values than when using the total electricity value.

[34] See e.g. [Rentz et al. 2006].

[35] More ambitious energy savings targets, amounting to 11.5% by 2015, which were supported by the European Parliament in its first reading of the original draft of the Directive on 7 June 2005, have finally not been established.

3.2.3 Requirements for future energy supply

The requirements that a future, sustainable energy system should fulfil can be derived from the combination of the general premises for energy supply (security of supply, economic efficiency, and environmental compatibility) with the trilogy of sustainability criteria (economy, ecology, and society). In the following list (based on [Nitsch et al. 2004, p. 43]) a set of such requirements for a future energy supply is formulated. While renewable energy technologies can fulfil the majority of requirements better than conventional technologies, there are several requirements that still need to be met by the renewable technology components of an energy supply system (written in italic letters):

- *utilisation and supply adaptable to the demand (availability, dispatchability);*
- long term security of supply;
- environmental and sanitary compatibility (air, soil, water, nature, and landscape);
- low risk and fault-tolerant; low system violability (resistance against terrorist attacks and sabotage);
- efficient use of resources (protection of fossil reserves, *minimisation of surface area used);*
- social compatibility (economic compatibility, equity among generations, acceptance);
- macro- and *micro-economic compatibility (economic efficiency);*
- *compatibility with existing infrastructures;*
- contribution to the national added value and job-potential;
- potentials for technology development and innovation (export stimulation);
- international compatibility (resistent to crises, equity of goods distribution).

3.3 Political framework for electricity generation from renewable energy sources

With power production still dominated by overcapacities and the negligence of external costs in electricity prices, it is currently impossible for significant shares of renewable capacities to penetrate the market without political backing. On 27 September 2001 *Directive 2001/77/EC* ‘on the promotion of electricity produced from renewable energy sources in the internal electricity market’ was adopted [EC 2001a]. This directive forms part of a range of policy measures taken by the European Union aimed at increasing the overall share of RES in primary energy consumption from 6% to 12% by 2010 as outlined in the European Commission’s White Paper on Renewable Energy Sources of 1997 [EC 1997]. The directive’s main function is to set indicative targets for the consumption of electricity produced from RES (RES-E) for the EU as a whole (22.1% by 2010) as well as on a disaggregated Member State basis, ranging from 5.7% in the case of Luxembourg to 78.1% for Austria.

An overview of the percentages of RES-E produced in the EU-15 countries in 1997 and the targets for 2010 from the above directive are given in Table 3.

Table 3: RES-E-use 1997 and targets for 2010 [EC 2004b]

Country (EU-15)	RES-E TWh in 1997	RES-E % in 1997	RES-E % in 2010	% increase
Austria	39.1	70.0	78.1	8.1
Belgium	0.9	1.1	6.0	4.9
Denmark	3.2	8.7	29.0	20.3
Finland	19.0	24.7	31.5	6.8
France	66.0	15.0	21.0	6.0
Germany	24.9	4.5	12.5	8.0
Greece	3.9	8.6	20.1	11.5
Ireland	0.8	3.6	13.2	9.6
Italy	46.5	16.0	25.0	9.0
Luxembourg	0.1	2.1	5.7	3.6
Netherlands	3.5	3.5	9.0	5.5
Portugal	14.3	38.5	39.0	0.5
Spain	37.2	19.9	29.4	9.5
Sweden	72.0	49.1	60.0	10.9
United Kingdom	7.04	1.7	10.0	8.3
EU-15	338.4	13.8	22.1	8.3

The preamble to Directive 2001/77/EC [EC 2001a] states the following reasons for RES expansion:

- environmental protection;
- creation of local employment;
- social cohesion;
- security of supply, and
- meeting Kyoto targets more quickly.

While primarily concerned with the security of supply, the EU Commission's *White Paper* [EC 1997] gives further reasons for increasing the share of RES, including:

- job creation, especially in small and medium enterprises (SME);
- facilitation of regional development and greater social and economic cohesion;
- opening business opportunities to the European industry;

- public support of RES vis-à-vis other sources of energy such as coal and nuclear.

Beyond these reasons, the directive also points to the potential contribution of RES towards the more general goal of a sustainable development.[36] Despite the advantages of an increased share of RES, the White Paper recognises that, if left to itself, the market will significantly under-provide renewable energy and therefore makes a case for government intervention.

The *Green Paper* [EC 2000b], which undertook a thorough analysis of all policy issues surrounding the Union's energy supply in the coming decades, reiterates many of the challenges identified in the White Paper, while specifically drawing attention to the growing dependence on imported energy carriers and the threats to economic and social development that could arise as a consequence. Following an assessment of the various energy sources, i.e. nuclear, solid fuels (coal and lignite), oil, natural gas, and RES, the Green Paper concludes that of all the available options, RES are the preferred energy source of the future given their potential abundance, low GHG emissions profiles, and indigenous availability. The Green Paper makes clear that RES will play an increasing role in energy supply only if assisted by governments.

From an economic efficiency perspective, a number of market failures justify state intervention in the RES-E markets. These are generally categorised under three headlines in the literature on energy market regulation:

- externalities associated with various sources of energy;
- under-investment in technological progress and innovation, and
- other market distortions[37].

In its report on the share of renewable energy in the EU, the Commission delivered its first detailed assessment of the progress made in the implementation of Directive 2001/77/EC. In the report, the Commission notes that all Member States have adopted targets for RES-E that are mostly in line with the Directive's indicative targets. The Commission further estimates that national policies currently in place will not suffice to achieve the 22% target by 2010, but rather a more modest 18 - 19%[38].

As a consequence of the Member States' free choice of adequate policy instruments, the efforts and the success of implementing the Directive on renewable energy

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[36] Most of these reasons are again taken up in COM(2004) 366: The share of renewable energy in the EU, Communication from the Commission to the Council and the European Parliament, 2004 [EC 2004b].

[37] Examples for such distortions are the oligopolistic structure of electricity generation and monopolistic structures of power transmission.

[38] The report largely blames this on the lack of comprehensive support policies in a number of Member States, especially with respect to biomass. With regard to the general target of a 12% share of RES in total energy consumption, the Commission points towards the big impact that a failure in reaching the RES-E target would have. The Commission estimates that if the share of RES-E reached only 18 – 19 %, an overall RES share of only 9% would be achieved.

sources differ widely among the Member States. Figure 5 shows the national intermediate achievements in 2002 (cp. [Ragwitz et al. 2005]).

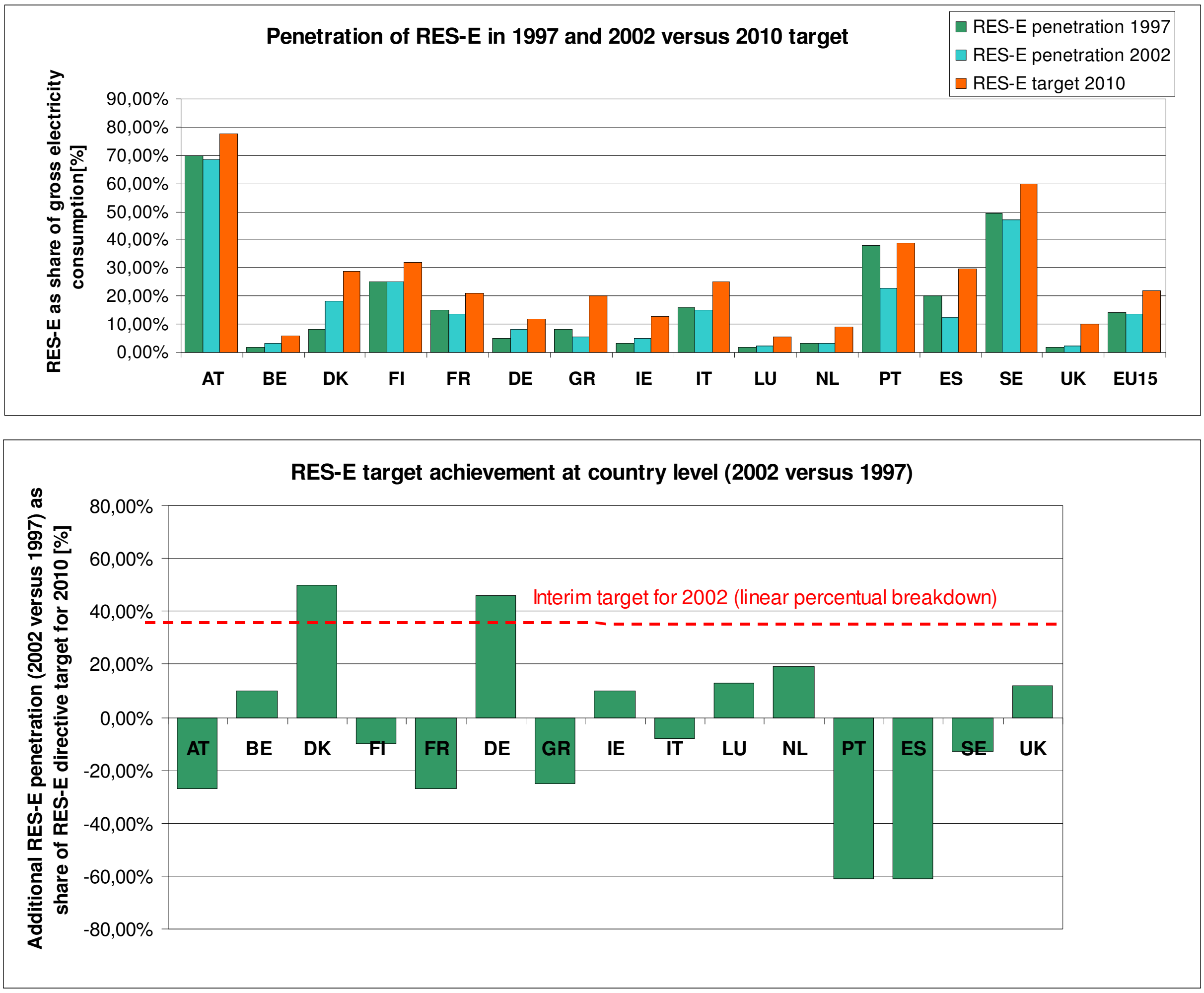

Figure 5: Overview on national interim achievements in implementing Directive 20011/77/EC

It can be stated, that some policy instruments, implemented at national level, only allow insufficient control of the finally resulting share of renewable energy utilisation. Some Member States will exceed their goals significantly, while others stay behind.

In the longer term this problem could be faced by a harmonisation of the national promotion schemes, taking into account that not every instrument is adequate in all phases of market launch of a renewable energy technology. Thus, while fixed feed-in tariff schemes, which normally provide high incentives and risk mitigation to investors, seem to be most effective and also more efficient than quantitiy-based schemes in the starting phase of renewable electricity development, it could be favourable to substitute them by a more competitive quota scheme, once the technology has achieved a certain level of market penetration[39].

While the RES-E directive has created a framework for a consistent political development with binding targets to be fulfilled by the Member States until 2010, this

[39] See e.g. [Zierul et al. 2005].

time horizon is relatively short when considering the lead times of large RES-E projects, as for example for offshore wind power. In order to achieve a continued security also for these kinds of projects it would be important for investors to get more certainty about how the framework conditions will develop after 2010. The EU Commission intends to release a communication on longer-term RES-E targets for 2020[40]. While in principle such plans can be considered as an important step for long-term investment security, concrete shares for the Member States are not yet decided upon and their effect can not be judged in more detail. For RES-E investors setting a definite longer-term target would be an important signal, and even if it is not immediately clear how much and what kind of support for their ventures they will exactly receive, it would be clear that there will be support efforts corresponding to the ambitiousness of the targets.

3.4 Available resources for renewable electricity

3.4.1 Mid-term potentials for renewable electricity in the EU-15

The term 'energy carrier potential' is used to characterise the amount of the available resource base of an energy carrier, which is available for use under certain premises. Different designations are used to define different types of potentials, depending on these premises (cf. e.g. [Kaltschmitt et al. 1993, p. 4 ff.], [Hensing et al. 1998p. 104 f.], [Klobasa et al. 2004], [Uyterlinde et al. 2003]). For a better illustration of the relationship of the different potential designations, these are graphically depicted in Figure 6. The potential terms are defined as follows: The theoretical potential includes the complete physically available energy flow of an energy carrier. After excluding those portions of the potential that can not be made use of due to technical constraints is called the technical potential. Several barriers exist, which limit the achievable portion of the available technical potential at a certain point in time. By further limitations taking consideration of public acceptance issues (cf. [Huber et al. 2004, p. 20]) it is diminished to the socially acceptable potential. Possible market growth rates and planning constraints further limit the possible penetration at a certain time to what is called the realisable potential[41]. The mid-term potential that will be referred to in the following is equal to the realisable potential for the target year 2020. In the long term, i.e. after 2020, the exploitable potential may be higher, for example due to considerable technological improvements made that are not foreseeable today.

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40 In this context, an overall target of a 20% share of RES in primary energy demand, translating into 1166 TWh, or more than one third of electricity generation from RES in 2020, has been proposed by the European Renewable Energy Council [EREC 2005b], [Uyterlinde et al. 2005]).

41 All restrictions are applied, except for economic ones (cf. [Uyterlinde et al. 2003]).

For 15 different renewable energy carriers for each country in the EU-15[42] the mid-term potentials have been determined in a comprehensive update of the mid-term potentials derived for the ElGreen study. These updated potentials[43] are taken as a starting point for the model-based analysis of RES-E to be conducted.

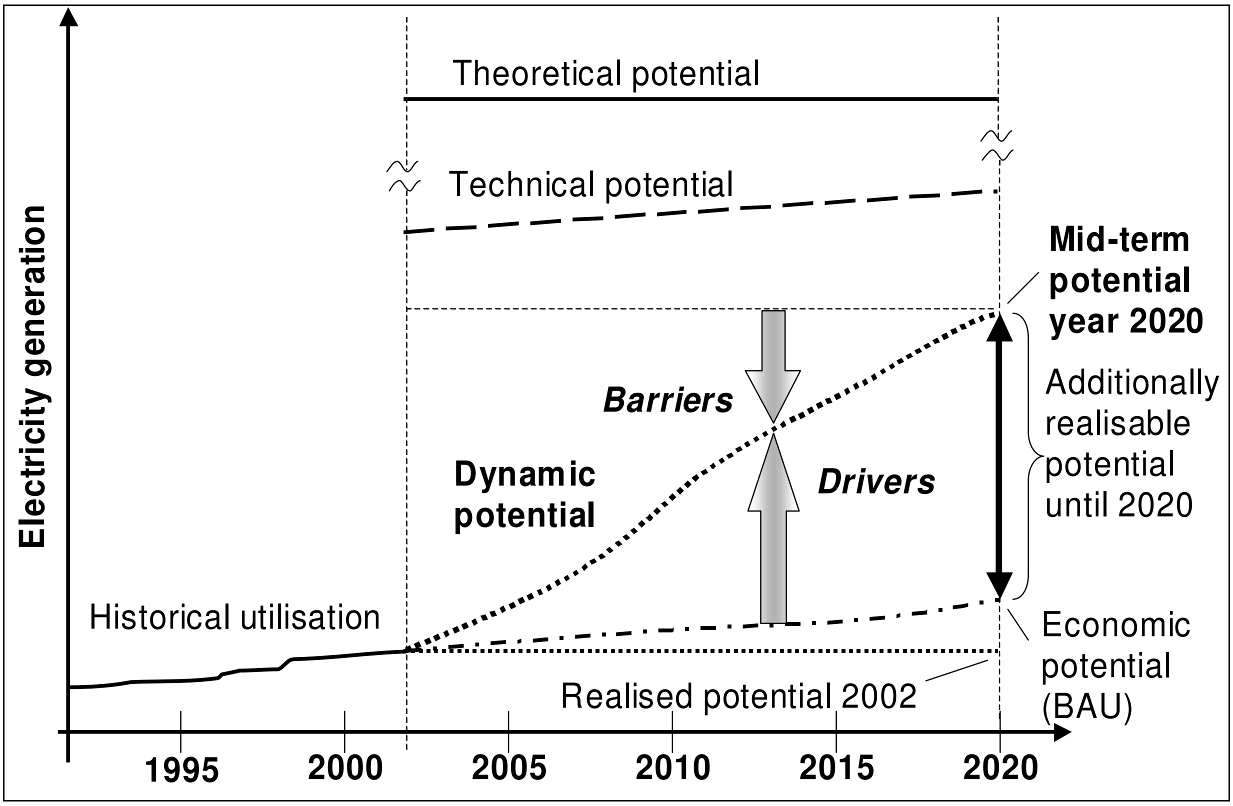

Figure 6: Deriving the mid-term potential for the year 2020 from the base year 2002 (based on [Kaltschmitt et al. 1993, p. 4 ff.], [Hensing et al. 1998p. 104 f.], [Klobasa et al. 2004])

Figure 7 shows the RES-E technologies' share of the total mid-term potential as estimated for the EU-15, amounting to a total of 1,545,601 GWh/a. Large hydro power and off-shore wind power can supply the largest shares of around 20% each. A more or less equally large share of 19% is contributed by the biogenous potentials, including sewage gas and landfill gas. Onshore wind power and photovoltaics follow closely behind with 17.1% and 15.8%, respectively. The remaining sources, i.e. small hydro power, wave, tide, solar thermal, conventional and HDR (Hot Dry Rock) geothermal, account only for minor shares of the overall potential.

42 The following description of the available potentials as well as the model-based analysis conducted and described in chapter 5 ff. will focus on the EU-15 and the realised shares of these 15 energy carrier potentials achieved.

43 In [Klobasa et al. 2004] the calculation methodology of the individual potentials as well as for the costs (see section 3.4.2) is described in more detail.

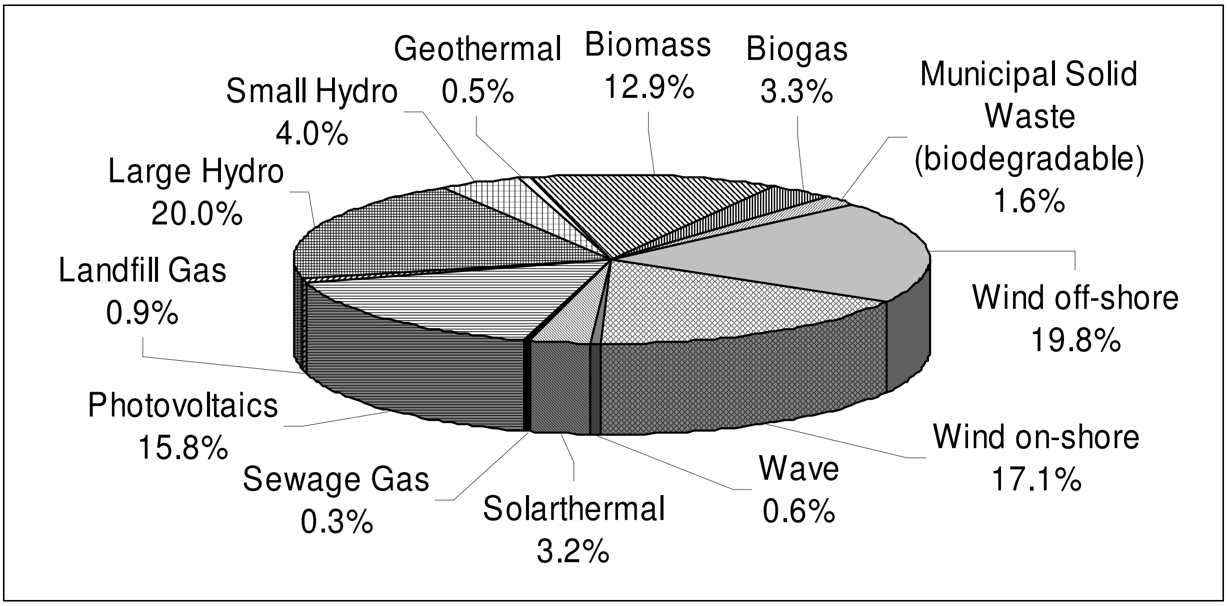

Figure 7: Composition of the mid-term realisable RES-E potential in the EU-15 (based on data from [Klobasa et al. 2004])

3.4.2 Renewable electricity production costs

In Figure 8 the ranges of electricity production costs for the above RES-E potentials are shown. The biogas category shown includes also sewage gas and landfill gas.

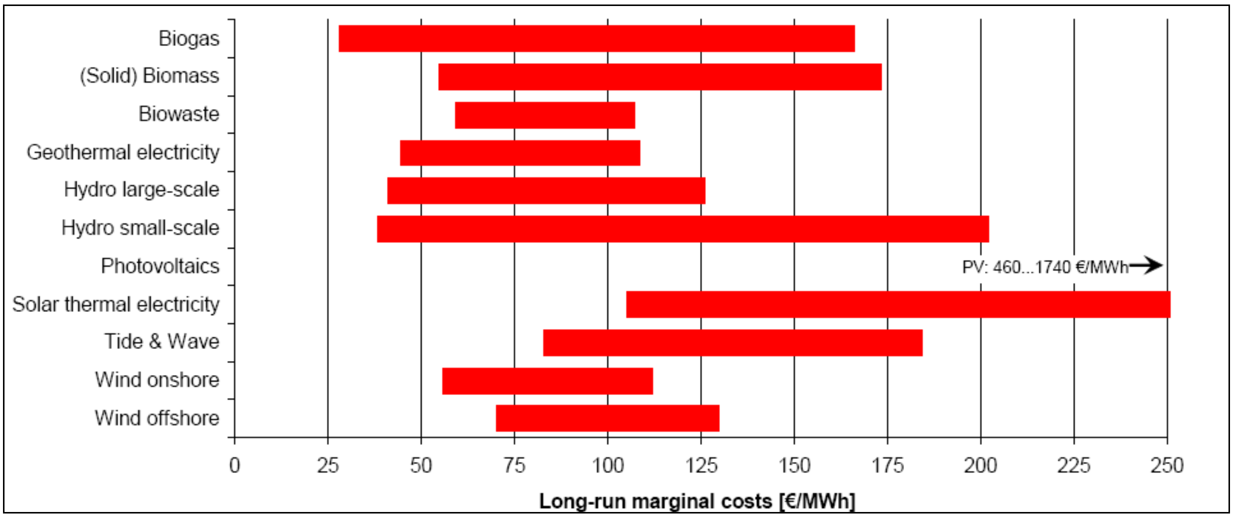

Figure 8: Production costs for different renewable energy carriers in the EU-15 (based on data from [Klobasa et al. 2004] [44])

[44] Ranges of electricity production costs can also be found e.g. in [Kaltschmitt et al. 2004]. An important aspect is the time dependence of generation costs, as the technologies to utilise the potentials may show improvements in both technical and economic efficiency. A prominent example is the production cost decrease achieved in wind power generation due to technology improvements and bigger turbine sizes. Between 1990 and 2005 production costs decreased by about 50% due to serial production and learning curve effects [BWE 2005a].

Due to the different conversion efficiencies of renewable energy technologies and the geographically inhomogenous availability of energy resources, there are large differences in the levels and the width of the cost ranges between the individual energy carriers. With comparatively low production costs and a rather narrow range between 5 cent/kWh for very good sites and 14 cent/kWh for the least favourable sites, large portions of on-shore and off-shore wind potentials are relatively favourable in terms of production costs. Also the biogenous energy carriers (with the exception of the broader cost range for biogas) and conventional geothermal show comparable production cost characteristics. Large and small hydro power as well as Hot-Dry-Rock geothermal potentials have broader cost ranges, but with similarly cheap potentials at the lower end of the range. The potentials with the widest production cost range and also starting at the highest cost are wave energy, solar thermal energy, and photovoltaics. The latter one has the most expensive potentials, ranging from 48 cent/kWh up to 165 cent/kWh. In addition to their heterogeneity with regard to costs, the available potentials are also spatially inhomogenously spread over the EU-15 Member States[45]. A comparison of the full costs of the most important renewable potentials in Germany and those of conventional power generation technologies is shown in Figure 9. While hydro power can already compete with conventional technologies, power from wind and biomass will only be able to do so at higher prices for fuel and / or for CO_2 emissions.

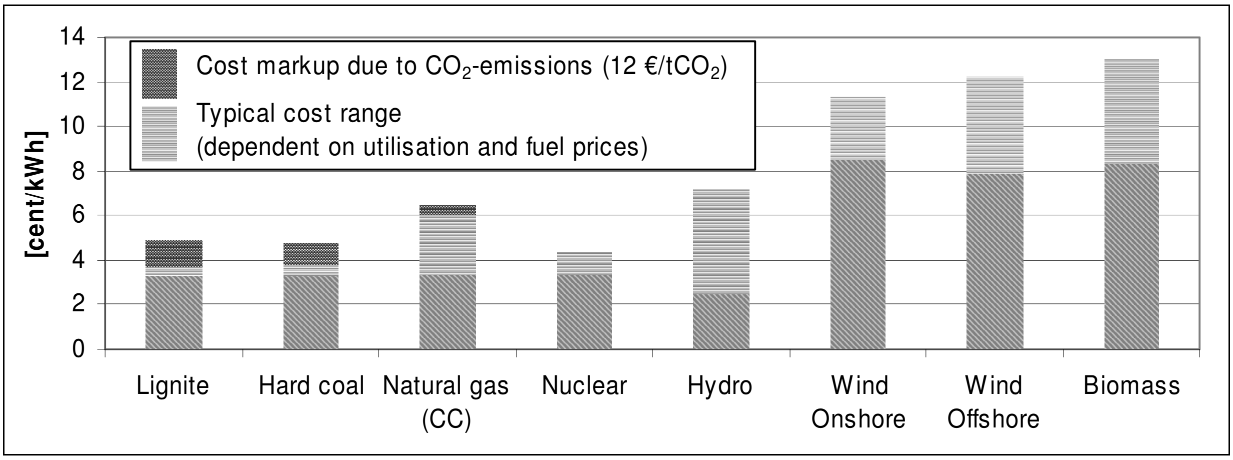

Figure 9: Cost ranges of conventional versus renewable power generation options (based on [VGB 2004])

The base year for the calculation of the mid-term potentials given is the year 2002, i.e. all potentials realised until this year only have to be accounted for with their annual fixed and variable costs. For the untapped potentials, investments have to be taken into account as well.

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45 Detailed analyses of the cost structures and the regional distribution of renewable energy carrier potentials are also available for a number of countries. The most recent of a row of comprehensive analyses for Germany is published by [Staiß 2003].

3.5 Incentive schemes for renewable electricity producers

Although some renewable energy sources, such as wind in prime locations and biomass, exhibit cost structures closely above or partly even below conventional sources, RES are generally considered to be not yet commercially competitive on an unprotected electricity market [Meyer 2003], especially as this market is still distorted by a large number of direct and indirect subsidies for the existing electricity system, and based on an infrastructure that was mainly built when the electricity sector was publicly owned [EEA 2004]. It is, however, argued that the scope for technological improvements to reduce generation costs is immense. Based on past experience, learning-curve effects and economies of scale are expected to lead to massive cost reductions in RES technologies [IEA 2002a]. Despite the long-term prospects of RES, the market might nonetheless under-invest in research and development because of short-sighted investment behaviour within the energy industry, and the public good nature of basic R&D, which is why government incentives for innovation should be provided [Rosegger 1996]. Although voluntary instruments[46] like green electricity offers have been frequently implemented by established utilities and specialised new market entrants, the efficiency of this type of instrument has been rather limited (cf. [Dreher 2001]). Thus, mandatory policy instruments seem necessary in order to achieve the aspired shares of renewable electricity. In the following and also in the model-based analysis the focus will be exclusively on the mandatory support instruments.

Since Directive 2001/77/EC does not set a community-wide framework regarding support schemes[47], the current EU renewable electricity market is characterised by a variety of incentive schemes adopted by the Member States in order to promote the development and deployment of renewable energy. Some support policies are designed to stimulate the supply of renewable electricity, while others affect the demand.

It should be noted that not all incentive schemes have the same relevance for the promotion of RES-E. National promotion regimes are usually based on one of the following primary support measures: feed-in tariffs, renewable quotas with a green certificate trading scheme, or, to a lesser extent, auctioning systems. A second group of relevant and complementary secondary support measures includes investment subsidies and fiscal incentives. In Table 4 an overview of the primary and secondary support measures that are applied in the individual EU-15 Member States is given. Countries usually have at most one of the schemes in the first group implemented,

[46] A classification and evaluation of different types of environmental policy instruments in general and for renewable electricity use in particular is given in [Rentz et al. 1999] and [Dreher 2001, p. 7 ff]. Generally, three classes of instruments are distinguished: mandatory regulatory instruments, mandatory economic instruments and voluntary instruments.

[47] A communication on an assessment of the experience with the variety of incentive schemes is required in this directive and was released in late 2005 [EC 2005e]. Its main conclusion is that it is still too early to harmonise the schemes and the insecurity introduced into the market by a sudden harmonisation would put the achievement of the 2010 targets at risk.

some countries like France and Belgium also use two schemes. The primary measures are usually supplemented by at least one measure pertaining to the second group. An exception is Finland, which exclusively uses secondary support measures.

Table 4: Overview of RES-E support mechanisms in the EU Member States [EC 2004b]

Incentives	Primary Support Measures			Secondary Support Measures	
	Feed-in tariff	TGC / Quota obligations	Auctioning system	Investment subsidies	Fiscal Incentives
Austria	X			X	X
Belgium	X	X		X	
Cyprus	X			X	
Czech Republic	X				X
Denmark	X				
Estonia	X				X
Finland				X	X
France	X		X		
Germany	X			X	X
Greece	X			X	X
Hungary	X				
Ireland			X		
Italy		X		X	X
Latvia	X				
Lithuania	X				
Luxembourg	X			X	
Malta					X
Netherlands	X			X	X
Poland		X			
Portugal	X			X	X
Slovakia				X	
Slovenia	X				X
Spain	X			X	X
Sweden		X		X	X
UK		X		X	X

3.5.1 Primary support measures

3.5.1.1 Feed-in tariffs

Feed-in tariffs are a commonly used policy instrument for the promotion of renewable electricity production. The term feed-in tariff is used both for a regulatory, minimum guaranteed price per unit of produced electricity to be paid to the producer, as well as for a premium paid on top of market electricity prices.

Feed-in tariffs are preferentially implemented as technology-specific tariffs and are granted to domestic generators of RES-E for the electricity they feed into the grid of the Member State concerned.

Regulatory measures are usually applied to impose an obligation on electricity utilities to pay the (independent) power producer a price as specified by the government. The tariff can be passed on to the electricity consumer. The level of the tariff is commonly set for a number of years to give investors security on their revenues for a substantial part of the project lifetime.

In order to be effective the tariffs should be designed to reflect at least the long-term marginal production costs. However, they are usually set at a somewhat higher level that also guarantees a profit for the investor in order to stimulate investments. From an investor's point of view, feed-in tariffs as a renewable energy promotion scheme provide the best investment security as they assure the investors' revenue. They can thus be regarded as a kind of medium- or long-term power purchase agreement.

The tariff, fixed per generator, may be periodically revised for new generations of RES-E plants, in order to account for possible decreases of production costs. This could be done e.g. by projecting progress curves, or on the basis of revealed cost reductions through benchmarking analyses[48]. Experience gained so far tends to prove that the feed-in tariff is indeed a very effective instrument in developing green electricity production.

Under a feed-in tariff scheme, the burden of additional costs from eligible RES-E in comparison to non-preferential electricity is normally carried by electricity consumers. For example, in Germany the feed-in tariff payments are being passed on to the power consumers on a pro rata basis. Only for energy-intensive industries relatively large tariff contribution discounts are granted.

Further, there are also so called **premium systems**, like the one currently being implemented in Spain[49]. This system consists of a premium paid per kWh on top of the electricity spot market price. This premium is set by a national regulator according to the applied technology and the installed capacity of the plant. The premium is invoiced to the distribution company. This system is paid for by electricity consumers through a charge that is added to their bill, proportional to their consumption. The

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[48] For instance, in the German system the feed-in tariffs depend on the year of commissioning, i.e. they are decreased annually for newly installed plants. Therefore, the later a new plant is installed, the lower the reimbursements received. This means there is a continuous incentive for efficiency improvements and cost reductions for new plants.The level of the tariff for a newly commissioned plant is normally guaranteed for 20 years, except for wind power, where an initial tariff is paid for at least five years and a basic tariff for the remaining years up to the completion of the twentieth year of operation. The initial tariff can be prolonged, depending on the energy yield of the site in relation to a reference energy yield.

[49] The Spanish support scheme for RES-E consists of two systems. One of them is a pure FIT and the other one is a premium per kWh paid on top of the electricity market price, according to Royal Decree 436/2004 (12 March 2004), on the methodology for updating and systematising the legal and economic regime of electric power installations within the so called Special Regime.

premium should reflect the social and environmental benefits of renewable energy sources, allow an adequate return on generating installations in special regimes, and reduce the uncertainty regarding the economic viability of generation projects using renewable energy sources.

3.5.1.2 Quota obligation with tradable green certificates

Green certificates are, first of all, a certification awarded to a produced quantity of RES-E. This certification allows to establish an accounting system to register production, authenticate the source of electricity, and verify whether the prescribed demand for green electricity has been met. When the certificates are tradable, they are referred to as tradable green certificates (TGCs). The main benefit of making them tradable is to stimulate the deployment of renewable energy based technologies in the most efficient areas of a country, or in a possible future harmonised EU-wide Community Support Framework, on a European scale in the countries with the most efficient production potentials. Moreover, TGC trading is expected to stimulate competition between producers, which should lead to declining costs of renewable electricity generation. Although based on the stipulation of a minimum quantity instead of a maximum allowance, the logic behind a tradable green certificate scheme and the potential economic benefits are comparable to that of the already implemented trading scheme for CO_2 emission allowances.

Usually, in order to create a demand for TGCs, regulatory measures are applied. This is done by imposing an obligatory quota of TGCs to be held by different actors, either electricity producers, consumers or transmission system operators. Minimum prices are set up in the green certificates systems and penalties fixed which influence the value of the green certificates.

Depending on the national energy policies, producers, consumers or distribution companies are obliged to hold a minimum number of TGCs, corresponding to a percentage of their yearly production or consumption. The obliged parties can either acquire these cerficicates by producing or consuming green electricity themselves or by buying them from other parties who have amounts in excess of their obligation. Thus, in the long term, the enforced demand for green certificates will lead to the establishment of a financial market for trading this commodity, allowing green electricity to be produced where it is most effective.

The main idea of creating such a market for TGCs is to ensure a politically planned deployment of renewable energy technologies as effectively as possible to maintain low consumer prices for power and enable an efficient renewable energy burden sharing. In particular, the market for TGCs should make it desirable to invest in renewable energy technologies, and ensure that investments are made in the most effective technologies and locations. Yearly quotas (targets) must be set up under the TGCs system.

Each time a green power producer sells electricity to the grid, he receives a corresponding number of TGCs. These certificates are financial assets and tradable. In addition to the physical power market, they can be sold in an organised, financial market established for green certificates and thereby realise an additional payment to the producer for his green power. Therefore, the TGC market de facto functions with two markets. On the conventional, physical electricity market, renewable electricity producers sell their electricity to the market operator receiving in exchange the wholesale electricity market price. On the financial TGC market, the ‘greenness’ can be traded separately from the physical commodity (cf. e.g. [Dreher 2001]). As a result of this, the obtainable price for the producer of renewable-energy-based electricity will be the sum of the market-based settling price for physical power and the price of the TGCs.

By letting the demand for TGCs follow annual goals the market design presents more risk for green electricity producers than in long term setting policies.

Since the TGC market, similar to the CO_2 Emission Trading Scheme, is independent of physical restrictions, e.g. confined transmission capacities, it allows for an unrestricted trade between countries and thereby represents a possibility to achieve a renewable energy burden sharing. Countries can lower their overall costs of meeting the targets by importing part of the certificates instead of completely realising their domestic target, or (in the case of abundant relatively cheap RES-E potentials available) export certificates.

The TGC system is still a fairly new market mechanism and only limited experience with this system exist. Therefore, although green certificate system are sound in theory, there is still the risk component and higher administrative cost creating a lot of uncertainty about how they will work in practice and about the actual design of the system that will be implemented in certain countries. In addition, there is also uncertainty about how these systems will interact on an international, EU-wide level [Jensen et al. 2002].

Generally it can be said that setting the annual quota level appropriately is a highly nontrivial task, which in principle requires that the policy maker knows the achievable market diffusion rates of all technologies (as compared to the requirement of knowing the marginal generation costs for all technologies under a feed-in system).

The main difference between a feed-in tariff system and a TGC system concerns the introduction of competition on both the renewable electricity market and the ‘grey’ electricity market. Thus, implementing a TGC system affects the amount of investor transaction costs. With respect to search and negotiation costs, for instance, the main difference is that under feed-in systems, renewable electricity producers do not have to find customers for their product on the market, only the grid and supply companies.

3.5.1.3 Auctioning system

Auctioning systems or tendering/bidding procedures can be used to select beneficiaries for investment support or production support (such as through feed-in-tariffs), or for other limited rights - such as sites for wind parks. Potential investors or producers have to compete through a competitive bidding system. The criteria for the evaluation of the bids are set before each bidding round. The government decides on the desired level of electricity from each of the renewable sources, their growth rate over time, and the level of long-term price security offered to producers over time. The bidding is accompanied by an obligation on the part of utility companies to purchase a certain amount of electricity from renewable sources at a premium price. The difference between the premium and market price is reimbursed to the electricity provider, and is financed through a non-discriminatory levy on all domestic electricity consumption. In each bidding round the most cost-effective offers will be selected to receive the subsidy. The mechanism therefore, theoretically, leads to the lowest cost options. However, as insecurities for investors are rather high in this context, the experiences made e.g. in Great Britain have shown that a continuous and cost-efficient realisation of RES-E projects is not necessarily guaranteed.

In order to maintain a differentiation in renewable energy sources, the bidding may be differentiated into bands of different technologies and energy sources. This means that wind projects compete against other wind projects, but not against biomass projects, for example. The marginal accepted bid sets the price for the whole technology band.

These procedures, which are designed to stimulate strong competition between generators of RES-E and hence lead to cost-efficiency and price reduction, have not shown great success in promoting RES-E, probably due to the complexity of the procedures involved in a tendering system. However, once bids are awarded they usually work like a feed-in scheme, giving a good deal of certainty to successful bidders.

3.5.2 Secondary support measures

3.5.2.1 Investment subsidies

RES-E plants are often capital intensive projects with relatively low variable costs. Therefore, governments may choose to promote RES-E use by introducing investment subsidies for RES-E technologies, e.g. in terms of Euro/m^2, Euro/kW, or a contribution of a certain percentage of total investment. Investment subsidies shift the marginal cost curves of the subsidised technologies, helping to make them competitive at market prices. Support can be modulated per type of technology, size, and geographical location of the installation. Such subsidies are the oldest and still the most common type of schemes. This may be explained by the fact that it probably is the most feasible political way to introduce non-competitive technologies into the market. However, a major disadvantage of this instrument is that it gives no incentive to operate the plant as efficiently as possible [Schaeffer et al. 2000], [Haas et al. 2001a].

3.5.2.2 Fiscal Incentives

A wide array of incentives can be grouped in this category. Among them are e.g. the exemption of RES-E from energy taxes, tax refunds, lower tax rates, e.g. for the value-added tax, the exemption of investments in RES-E plants from income or corporate taxes, etc. All of these measures increase the competitiveness of RES-E and may be applied to existing installations (generation-based incentives) and / or newly built ones (capacity-based incentives).

Fiscal and financial incentives are very widespread, probably because they are usually easy to implement given that fiscal structures are already present in all countries. However, it is important to note that they usually represent secondary promotion measures. For instance in countries with quota obligations, fiscal incentives are usually put in place to stimulate demand. Fiscal incentives obviously only work properly as a main incentive in Member States with a high level of taxation.

3.5.3 Harmonisation of European renewable electricity promotion

It is frequently argued that a harmonisation of European RES-E promotion schemes would allow for a more efficient support of renewable electricity generation. Possible benefits that could result from a harmonised Community Support Framework (CSF) for renewable energies are theoretical cost savings in reaching renewables targets, a smoother functioning of the European RES markets and reduced market distortions and policy spill-over effects stemming from national schemes[50]. On the other hand, the most important drawback of an early harmonisation would be the uncertainty introduced by such a significant change in the political framework for RES-E use. The disruption resulting from the necessary adaptation to new market rules could delay or even stop the further exploitation of RES-E in the EU for some time, thereby putting the achievement of the 2010 targets at risk.

In order to maintain planning security for investors, Directive 2001/77/EC specifies a transition period of at least seven years beginning with the decision to adopt a harmonised scheme. Two questions need to be answered in this context, which are not completely independent of each other. Firstly, when and under which circumstances is a harmonisation favourable? Secondly, if steps towards a harmonisation are taken, what kind of a CSF, feed-in tariffs or a tradable green certificate scheme, would be accepted by the Member States and would deliver the greatest societal benefits, given the many policy goals pursued by expansion in RES?

The scientific community is rather discordant about which system to choose. Proponents of a harmonised quota scheme include e.g. [Morthorst 2001], [Nielsen et

[50] The benefits mentioned here are in line with the ongoing completion of the internal energy market.

al. 2003], [Menanteau et al. 2003]. On the other hand, a harmonised feed-in scheme is supported e.g. by [Hvelplund 2001], [Meyer 2003], and [Huber et al. 2004]. While one of the major arguments used in favour of quota-based mechanisms is their higher economic efficiency, it is also claimed that this (theoretical) advantage has not yet been observed in practice [Butler et al. 2004].

Also when mapping the industry stakeholders' positions regarding the mechanism of choice for a community support framework there are conflicting views. A TGC scheme is strongly advocated by the representatives of the utility industry (e.g. by [Eurelectric 2004a], [Eurelectric 2004b] and [VDEW 2005]). Due to its greater complexity with higher risks involved in the planning and realisation of projects such a scheme would arguably be the most beneficial one for established oligopolistic market players. It is thus comprehensible why the alternative option of a harmonised feed-in tariff scheme (Renewable Energy Feed-In Tariff or REFIT scheme), which reduces the risks for investors[51], is favoured by the representatives of independent renewable power producers, such as the European Renewable Energy Council [EREC 2005a], the European Wind Energy Association [Kjaer 2004], and the European Renewable Energy Foundation [Fouquet et al. 2005]. The aforementioned renewable industry organisations are in favour of national REFIT schemes, while recommending a wait-and-see strategy to learn more about quota schemes before a complete harmonisation.

On the political stage, those Member States already using REFIT systems tend to be critical towards an early move to a quantity-based system due to the increased amount of risks of those systems and the different level of maturity of the various RES-E technologies. The primary focus on cost-efficiency of TGC schemes also has potentially adverse effects on the dynamic efficiency of such a scheme. With only the most competitive technologies able to be expanded the use and the improvement of less mature and thus less competitive technologies would be strongly affected in the early phase of market development. The latter is also true for a single, one-fits-all REFIT scheme. Any harmonised support scheme should thus be adequately designed to allow also for a sufficient stimulation of the development of promising, but less mature technologies, i.e. to enable dynamic efficiency.

The EU Communication released in December 2005 [EC 2005e] recommends not to harmonise RES-E support throughout the EU in the first instance. Instead, it is planned to reassess this issue in 2007, allowing more experiences to be made. The main reasons stated for this recommendation are the otherwise expected market disruption and the possibly resulting discouragement of investors due to the actual or perceived increase of investment risks, but also due to the insufficient experience with quota-based TGC systems. Given the comparably short period of their existence they have not yet had the same time as price-based mechanisms to prove their

[51] For a description of experiences with renewable energy projects under different promotion schemes in Europe and the risks for project investors see e.g. [Rentz et al. 2004].

theoretical benefits in real life. The assessment of the further experiences made will be useful to define a strategy for the future of renewable energy support in the European Union. It is important that clear and robust policy strategies are derived as early as possible in order to ensure an efficient and effective further development of renewable electricity generation in the medium to long term, with administrative barriers removed wherever possible.

Such strategies should, however, not exclusively be based on recent historical experiences. As the development of renewable electricity generation is always dependent on the interrelations with other electricity sector framework conditions, it is important to take into account the possible future development of these framework conditions as well. The necessity to consider these interactions implies that the decision making process on the way to derive such an efficient and robust strategy is a highly non-trivial task.

In this context, the optimising energy system modelling approach developed in this work can provide valuable input. Within the framework of the entire European electricity system it allows to model quantity- as well as price-based support strategies on a national level as well as in a harmonised European context. Moreover, next to its flexibility concerning alternative future energy sector framework conditions, the approach is able to take into account the existing interactions between renewable and conventional electricity generation, as well as those between the markets for power and CO_2.

4 Integration of renewable energy sources into electricity supply

4.1 Availability and production characteristics of renewable electricity generation

As opposed to electricity generation from conventional fuels, which historically has mostly been centralised and located close to the centres of demand, RES-E generation usually shows different characteristics. Renewable electricity sources are geographically dispersed and not necessarily available in the required quantity near the electricity demand centers. The availability of utilisable RES-E potentials is regionally quite differentiated and often the best sites for RES-E utilisation are in remote areas. Unlike the situation for conventional fuels, the transportation of the primary energy carriers over longer distances is often not economical or not feasible, as e.g. for energy from wind or waves. Thus, increasing RES-E production leads to a decentralisation of the power supply structure, necessitating that the electricity produced is carried to the consumers via the power grid. New grid connections are necessary for areas that formerly were not connected, or existing grid structures have to be reinforced to adapt to the changed power flows (see e.g. [EWEA 2003b], [Dena 2005], [EWEA 2005] and [UCTE 2004d]). An increased future use of renewable electricity thus also needs to be assessed from the aspects of grid stability, load flows, and transmission bottlenecks. While the use of RES-E strengthens the long term security of fuel supply by displacing imported fuels with indigenous resources, the temporal and geographical variability of these energy carriers poses additional challenges to the operational reliability of electricity supply. Moreover, the costs for the exploitation and utilisation of the resources also vary considerably. Thus, the introduction of large amounts of RES-E and the political incentives applied have a much greater influence on the regional structure of electricity supply across Europe than the use of conventional power technologies[52]. Apart from lignite and other regional energy carriers like peat, the latter have much more homogenous availability, both regionally and with regard to utilisation costs.

Regarding the variability and predictability of their output, which determines their typical production profiles and dispatchability, plants that deliver electricity from renewable sources can be grouped into three categories (cf. [Schulz et al. 2004]):

The first group is characterised by the fact that they can, in principle, be dispatched according to demand changes and have a good short-term predictability. Biomass,

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[52] Also conventional technologies are more and more applied in a decentralised manner. Especially advantageous is the increased fuel efficiency that can be achieved in decentralised cogeneration systems for heat and power. In order to guarantee a more predictable behaviour of decentralised generation, concepts for so called virtual power plants are developed. Descriptions of relevant technologies and concepts can e.g. be found in [Bitsch et al. 2002], [Arndt et al. 2002], [Hollmann et al. 2005], [Degner et al. 2002].

sewage gas, landfill gas, mine gas, as well as geothermal plants and storage reservoirs belong to this group. However, when fixed feed-in tariffs are granted and with the exception of storage reservoirs, these sources can be regarded as base load electricity generators, as they have no incentive to vary their load over time.

The second group is made up by run-of-river hydro power plants, whose output can be varied only to a limited extent and shows seasonal variations and limitations of availability. However, the predictability of their output is very good in the short term and also quite good in the long term.

The third group comprises electricity generation from wind turbines and photovoltaic plants. Their output is subject to short-term (minutes to hours), medium-term (hourly or diurnal), and long-term (weekly to yearly) fluctuations. While the predictability of short- to medium-term fluctuations are subject to significant margins of error, the longer-term fluctuations can be considered in the investment and revision planning process of conventional power generation capacities by means of statistic analyses to determine the so called capacity factor or the secured capacity.

4.2 The special role of wind energy

In many European regions, wind power fluctuations already are a dominating factor for the feed-in characteristics of all renewable electricity sources (cf. the exemplary feed-in time series in Figure 10). The main reason is that compared to other renewable energy options, considerably higher overall capacities of wind turbines are installed, mainly due to their significantly lower costs in comparison to other renewable energy carriers with fluctuating availability like solar thermal or photovoltaic converters[53].

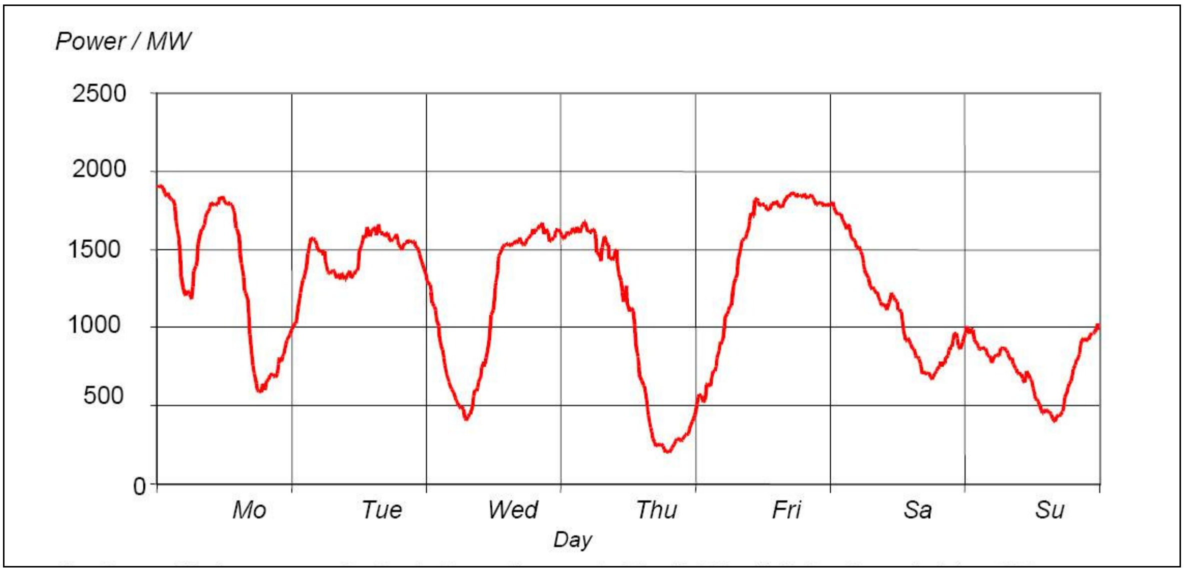

Figure 10: Wind energy production in the northem part of the E.ON-grid during the period Jan. 31th until Feb. 06th, 2000 [Luther et al. 2001].

[53] Please refer to the renewable generation cost structures in section 3.4.2. The above reasoning is also quantitatively supported, e.g. by [Sensfuß et al. 2003, p. 78].

While also hydro power shows a variable availability throughout the year, these fluctuations are sufficiently slow not to interfere with the day-ahead production schedule of conventional power plants.

In the following passages, special consideration shall thus be given to the characteristic nature of wind power generation and the effects resulting thereof.

4.2.1 Characteristics of the wind resource

The availability of wind energy, i.e. the wind speed at a given location, shows annual, seasonal and diurnal fluctuations. Moreover, the utilisable wind resource varies according to the topographic situation. These variations need to be taken into account when assessing the possible wind energy yield at a specific site.

In a semi-empirical approach the known average wind speed of a nearby location can be used to project the wind speed for the location of interest by taking into account the roughness parameters of the landscape type and the geostrophic wind. This principle has been applied in the European Wind Atlas [Troen et al. 1989] and the World Wind Atlas [Troen et al. 2002] and is often used for site assessments [EWEA 2003b]. The reliability of this approach does crucially depend on the roughness values used. Due to the less complex flow regimes, better results are generally achieved in coastal regions than in more complex terrain, as e.g. in mountainous regions [EWEA 2003b].

In order to calculate the expected energy yield of a site the mean annual wind speed is not sufficient. Additional information about the statistical frequency of wind speeds in the possible spectrum is necessary [Hau 2003].

If no measurements are available, the distribution function of the wind speed v can be estimated using the Weibull distribution [Hau 2003]. It is defined as

$$\Phi(v) = 1 - e^{-\left(\frac{v}{c}\right)^k} \tag{4.1}$$

Φ Distribution function

c Scale factor

k Form parameter

Differentiation of this distribution function yields the density function or frequency distribution (see e.g. [Lewald 2000]):

$$\varphi(v) = \frac{k}{c} \cdot \left(\frac{v}{c}\right)^{k-1} \cdot e^{-\left(\frac{v}{c}\right)^k} \tag{4.2}$$

φ Density function

Values for c and k can be derived from the European Wind Atlas (e.g. for Fuerteventura: c = 7.2 m/s, k = 2.78)[54].

φ(v) indicates how frequent a wind speed v occurs[55]. The Weibull distribution is used in the European Wind Atlas and in other forecast models (cf. [Giebel 2001]).

4.2.2 Prediction of wind power production

Different types of forecasts are necessary to predict the output of wind turbines on different temporal and geographical scales. As descibed above, for the investment planning of a potential site the long-term characteristics of the wind resource at that site are of essential importances for the developer. On the other end of the scale, the short-term prediction of the overall wind power yield of all wind turbines in specific areas of the transmission grid is valuable information for grid operators and the day-ahead production planning of conventional power producers.

When calculating the energy yield of a wind farm, three elementary steps are necessary. The first input is the prediction of the long-term variations of wind speed over the sites at the hub height of the turbines. Secondly, the wake losses arising due to the operation of one turbine operating in the wake of another, the so called wind park effect, have to be taken into account. Finally, all kinds of other losses, as e.g. due to substation maintenance, blade degradation, and electrical transmission efficiency, need to be calculated or estimated. The task of predicting the energy yield of wind farms is commonly assisted by the application of computer based, so called wind farm design tools. In addition to the wind speed data gathering described before, additional input is necessary which includes (cf. e.g. [EWEA 2003b]):

- wind farm layout and hub heights;
- turbine characteristics;
- predicted long-term site air density and turbulence intensity;
- topography of the site and the surrounding area;
- surface ground cover.

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54 For k = 2 (in case only the average wind speed is known) the Weibull distribution becomes a Rayleigh distribution: $\Phi(v) = 1 - e^{-\left(\frac{v}{c}\right)^2}$

with the density function: $\varphi(v) = 2\left(\frac{v}{c^2}\right)e^{-\left(\frac{v}{c}\right)^2}$.

The scale factor c depends on the average wind speed. Typically applicable for central Europe is:

$$c = \sqrt{\frac{4}{\pi}} \cdot v_m$$

55 Strictly speaking, the value of the density function does not express the probability of a realisation of a random variable X in the point x, due to the fact that P(X=x)=0 for continuous probability variables. Nevertheless the density function of a continuous random variable can in some respects be regarded as a frequency function [Bamberg et al. 2001].

The above interrelations are valid for the wind speed at one specific location. If wind speed forecasts are to be used to calculate the temporal profile of the expected wind power feed-in for a larger area, the temporal and spatial correlation of wind speeds at different sites needs to be taken into account (cf. e.g. [Giebel 2001], [Rohrig 2003]).

Models that are able to provide forecasts for the temporal characteristics of wind power production for larger areas are of special interest for utilities to provide assistance in power plant scheduling and grid operation[56]. For this task new and improved approaches are continuously developed, as the task of predicting wind power has become more and more important for energy traders and transmission system operators, mainly due to cost reasons.

Existing wind power prediction models follow different methodological approaches. On the one hand there are statistical models and artificial neural networks using only wind speed and other relevant data (e.g. temperature) time-series as input, often from numerical weather prediction models. On the other hand there are physical models, which incorporate physical parameters of the environment and the topography to predict wind power in different regions. Also combinations of both approaches exist, joining their advantages. While statistical approaches are more precise for predictions concerning a time horizon of up to six hours, physical approaches are more reliable for longer time horizons of up to 72 hours[57]. Models using numerical weather prediction (NWP) for their prognoses are generally considered to be more exact and reliable.

Apart from their methodology wind power forecast models can also be distinguished depending on their purpose, as e.g. the planning of individual wind parks or the forecast of wind power production from a larger area. Other criteria for a differentiation are the temporal or geographical areas of model application, as e.g. models for long-term or short-term prediction, or for applications in coastal areas or more complex terrain.

4.3 Technical implications of fluctuating power generation

As mentioned, the critical relevance of wind power production is connected to the fact that wind as the prime mover of wind turbines fluctuates randomly and can thus not be scheduled. Compared to other RES-E options the use of wind energy shows comparatively low costs and significant potentials in a number of EU countries (cf. chapter 3.4). Thus, more than any other renewable electricity source, and especially in countries with high or fast growing penetration rates of wind energy use in power generation like Germany, Spain, and Denmark, wind power with its high volatility and

[56] The development and the application of a model for online wind energy monitoring and prediction in Germany, which helps to improve conventional power plant scheduling, is described in [Ernst 2003].

[57] An overview over different wind power prediction methods and tools is given in [Giebel 2003] and [Rohrig 2003].

limited predictability requires a greater adaptability of the conventional power plant portfolio.

Operational problems can arise due to the structure of the grid as well as of the conventional plant portfolio (see e.g. [Boxberger 2002], [Leonhard et al. 2002]). Particularly for planned large offshore wind parks, this problem is regarded as an important issue, as a large power supply with a fluctuating nature is concentrated in remote and weak areas of the grid[58]. The sometimes extreme load variations in the grid caused by the fluctuations, as shown in Figure 10 and Figure 19, need to be compensated by the remaining power plant portfolio. This could partly be accomplished by conventional reserves and also by hydro power reserves, e.g. in the Alps [Krämer 2003][59]. The grid connection of large (offshore) wind parks, the capacity structure, the role of hydro power, and the scheduling of reserve capacities, as well as the extension of the plant portfolio and the grid are thus central aspects for the future of electricity supply.

Further technical challenges resulting from the special characteristics of wind power technology can be described as follows (see e.g. [UCTE 2004d]):

- Logistic limitations of construction and grid connection due to remote sites, especially offshore.
- Back-up capacities are required. At an average availability of 20% of the total power installed over the year, less than 10% of the capacity is available for one third of the year. This is particularly relevant in peak consumption periods, as the annual peak load in winter, or under aggravated generating conditions as during the heat wave in the summer of 2003.

4.3.1 Interactions with conventional power generation

Generally, two problematic fields arise as a result of the fluctuating character of wind power production. On the one hand, the control theoretic problem of adapting conventional power plant schedules must be solved, and on the other hand, the varying availability of wind power capacities raises questions about how much conventional capacity can be replaced in the long term. It is thus a challenge for utilities to incorporate wind power generation into their long-term expansion planning [Hau 2003].

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[58] Electricity networks are characterised as ‘strong’ or ‘weak’ with regard to the sensitivity of the grid voltage level for changes in generation and demand. The determinant for the ‘strength’ of a point in the network is the impedance between that point and the main generators of the system [EWEA 2003a]. The short-circuit level (measured in MVA) gives an indication on the strength of an electrical system.

[59] The possible role of Alpine hydropower in this context has been the subject of several studies, e.g. [Möst 2006], [BFE 2004]. Also for the Scandinavian power systems, where hydropower is a dominating electricity source, the complementarity with wind power feed-in has been assessed, e.g. in [Vogstad 2000] and [Holttinen 2004].

The results of different studies indicate that fluctuations in the time scale of minutes are levelled out quite well due to the broad geographical distribution (e.g. [Walve 1982], [Dany et al. 2003], [Dena 2005]), but that higher variations can occur on an hourly scale. In [Hau 2003] a hypothesis is formulated that a power plant portfolio with a high share of intermediate load power production can absorb a high wind capacity. Early theoretical analyses have concluded, that wind power shares of up to 20% of the grid load can be absorbed without major control problems [EC 1990]. In the meantime, sufficient practical experience exists where this threshold has been reached already, as e.g. in the grid of the Danish utility ELSAM, and no major control problems have arisen (see e.g. [Hau 2003]). In order to achieve such a seamless integration of high wind power production, the conventional power plant portfolio needs to adapt its production adequately at all times. This includes the provision of sufficient reserves and balancing power. The general principles of their provision as well as the additional requirements caused by increasing wind power feed-in are shortly described in the following.

Balancing power is needed in the case of an imbalance between the supplied and the demanded power. The discrepancies can be caused on the supply side as well as on the demand side, i.e. positive as well as negative balancing power can be required [VDN 2005, p. 2]. Positive balancing power from reserve capacities is required to equalise an unexpectedly low power production or an unexpectedly high demand, while negative balancing power equalises an unexpectedly high power feed-in or an unexpectedly low demand. According to the requirements established by the UCTE[60] for the interconnected European transmission grids, primary, secondary, and tertiary reserve are distinguished. In addition, time control is used for adaptations of the system frequency in the longer term. In Figure 11 the interrelations between the different control mechanisms are illustrated graphically.

Primary reserves are provided by all transmission system operators (TSOs) in the synchronised UCTE grid area. In the case of a disturbance or even a power plant failure, the resulting power shortage is instantaneously compensated by a lowered rotational speed of the other grid-connected generators, i.e. a decreased frequency. By the activation of primary reserves (opening of throttle valves in front of the steam turbine) a further decrease of the frequency is prevented and a new state of equilibrium is reached [Valentin 1987]. The activation begins immediately after a disturbance, within 30 seconds primary reserves must be fully activated. They must be available for the duration of 15 minutes after a disturbance [VDN 2005, p. 2], [UCTE 1998]. Secondary reserves must be provided by the TSO responsible for the disturbance. Their activation begins automatically 30 seconds after a disturbance, and they must reach their full capacity within 5 minutes after a disturbance. [VDN 2005, p. 2], [UCTE 1998]. Secondary control replaces the temporal power deficit and frees the primary reserves for possible new disturbances [Valentin 1987, p. 14 f]. The

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[60] **U**nion for the **C**oordination of **T**ransmission of **E**lectricity.

duration of secondary reserve deployment is limited by technical and economic reasons, and for continuing imbalances tertiary reserve is manually activated. After up to 15 minutes, primary and secondary reserve must completely be substituted by manually activated tertiary reserves.

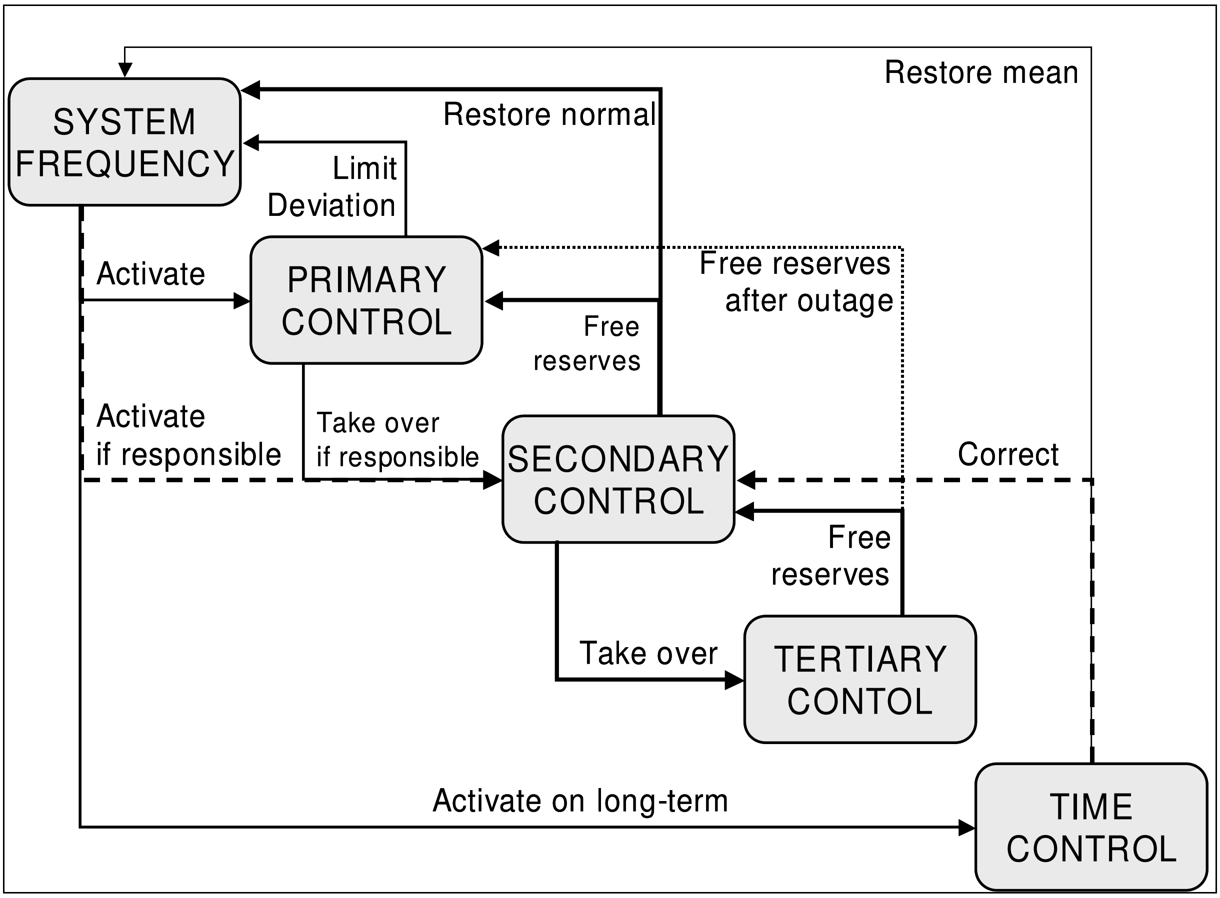

Figure 11: Functions and interactions of control power types [UCTE 2004a]

Tertiary reserves can be categorised into stand-by and spinning tertiary reserves. Gas turbines or even more quickly reacting pumped-storage plants, which can activate their full capacity within a few minutes, are counted as standing tertiary reserve, while the spinning reserve is constituted by the unused capacity margin of power plants already operating. The dynamics of the activation of spinning reserve depends on the maximum ramp rate of the output of the power plants. Providing spinning reserve also means operation at partial load with a reduced efficiency and thus influences fuel consumption, eventually causing additional related costs and emissions. If a shortfall of capacity is foreseeable somewhat longer beforehand, a more economic option is to bring additional capacities online instead of an extensive use of spinning reserves, which are characterised by higher variable costs.

In the future an increase of the reserve requirements can be expected, as in addition to load forecast errors and non-scheduled plant outages the increasing share of renewable energies and their forecast errors will lead to imbalances between supply and demand of electrical energy. The additional requirements caused by large wind energy feed-in in terms of power plant reserves are illustrated in Figure 12.

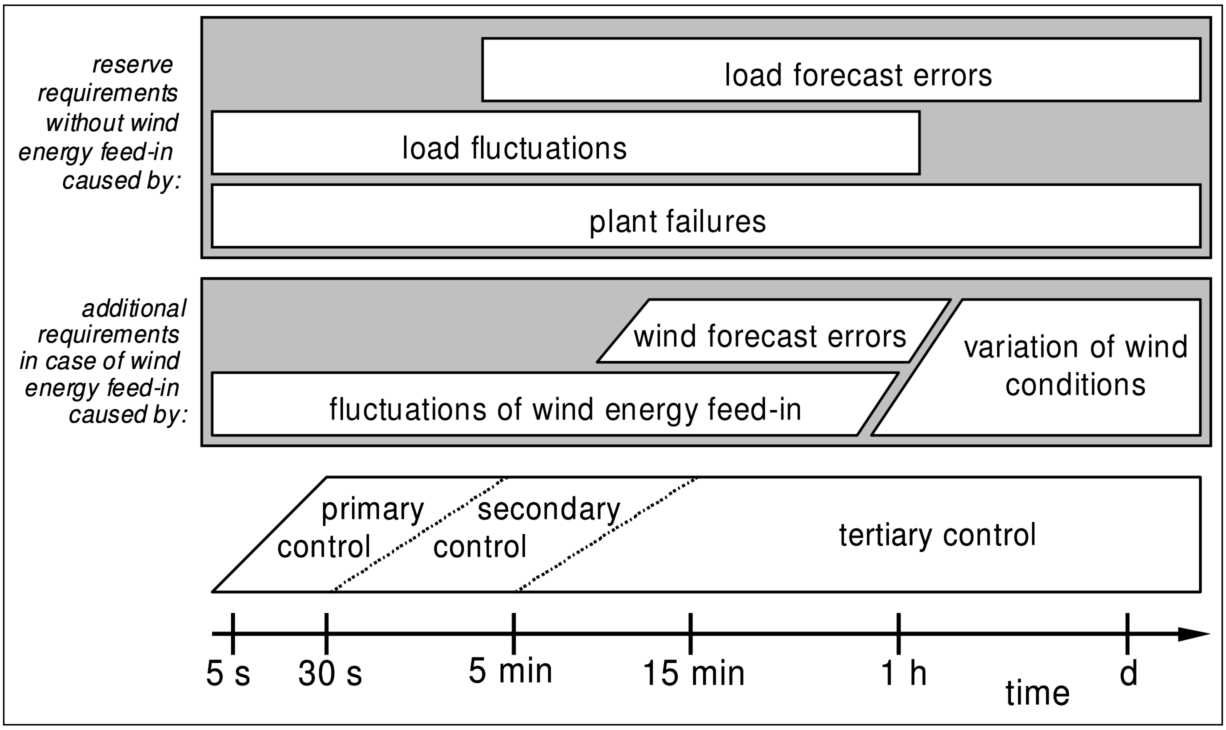

Figure 12: Reserve requirements in power systems with large wind energy feed-in (adapted from [Dany 2000])

This figure also relates these requirements to those caused by the conventional part of the power systems without wind energy feed-in. As already stated above, wind power fluctuations on a very short time-scale, i.e. in the area covered by primary reserves, level out each other quite well, which limits their influence on this type of reserve. To some extent the effects caused concern the requirements for secondary reserve, but due to forecast errors and the variation of wind conditions most substantially those for tertiary reserves[61].

According to the German grid study [Dena 2005], an average additional positive (negative) balancing power reserve of 1200 MW (750 MW) were necessary in Germany in 2003. The maximum amounts to about 13.8% of the overall installed wind turbine capacity of 14.5 GW. For 2015 it is expected that an additional reserve of 3200 MW (2800 MW) up to a maximum of 7000 MW (5500 MW) will be necessary, at an installed wind power capacity of 36 GW [Dena 2005, p.251 ff.].

4.3.2 Grid interactions

Difficulties can arise, especially where large wind parks need to be connected to a weak part of the grid, e.g. in the case of offshore windparks in sparsely populated

[61] In Germany, the current structure of the day-ahead market for secondary reserves (‘Minutenreserve’) with the necessary prequalification of market participants (e.g. a minimum of +/- 30 MW, full dispatch of offered capacity within 15 minutes, etc.), a limited number of market participants as well as four existing grid areas, gives incentives for the grid operators to balance wind energy fluctuations as much as possible with the available reserves on this market, which due to the smaller competition and higher prices is more profitable than the market for tertiary reserves (‘Stundenreserve’).

coastal regions without big industrial electricity consumers, and where transmission lines are weakly dimensioned. In the case of Germany, high voltage lines in these areas are often limited to 110 kV, with 400 kV lines installed only close to large power plants[62].

Due to their high electrical output, wind parks in the category of 1 GW must be connected to the highest voltage level (400 kV), which implies that this type of transmission line will have to be extended in order to enable the grid connection of large offshore parks (cf. [Dena 2005], [EWEA 2003b]). A further electrical problem are grid interactions, especially the demand for reactive power by asynchronous generators and harmonic distortions, which result from the use of DC converters. Moreover, an increased use of power electronics is also a source of additional failure probabilities[63]. Several other issues arising from an increasing feed-in of wind power into the grid are listed in the following:

- Grid compatibility issues due to generator types used (insufficient fault ride-through capability, reactive power balancing, frequency fluctuations).
- Additional congestion management necessary due to new and aggravated existing bottlenecks in the grid. At least until sufficient new power lines are constructed, generation management concepts[64] of wind parks can help to avoid congestion.
- Costs for balancing power and grid reinforcements must be allocated. Regulators and Governments must decide whether to socialise the costs or to charge them either entirely or partly to the parties causing them[65].
- Wind power affects cross-border electricity transits, limiting the existing available capacities for European electricity traders.

In the wake of the liberalisation of the European energy markets an increasing importance of inter-regional power flows is expected (cf. e.g. [Brauner 2003], [Verstege et al. 1997], [Dena 2005]), which causes a higher utilisation of existing

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62 For the time being, the only 400 kV transmission line connecting the northern part of Germany to Denmark is already largely utilised by energy exchanges in the UCTE control area.

63 These aspects shall not be treated in depth here, reference is instead made to [Lewald 2000] and [Gasch et al. 2002].

64 Generation management concepts for wind parks, which are necessary especially for large offshore parks, are e.g. described in [Hoppe-Kilpper 2003]. They can involve an active participation of wind turbines in guaranteeing grid stability, e.g. by limiting output gradients, coordinating the starts and stops of turbines or by installing turbine types that can contribute to reactive power compensation.

65 While the regulations of the German feed-in law EEG provide for a compensation of differing amounts of feed-in tariffs paid by the individual transmission system operators, there is no such compensation for the additional ancillary services necessitated by the fluctuating wind power feed-in. As there are four transmission zones in Germany, which each have to be balanced on their own, there are efficiency potentials in terms of ancillary services which could be realised if the number of transmission areas was reduced. An intra-day market instead of the currently applied day-ahead trading procedure for balancing energy could also make the balancing energy market more competitive and efficient.

interconnectors and leads to an aggravation of existing grid bottlenecks[66]. The impacts of wind power on the transmission grid can be differentiated into local and system-wide impacts. For both categories the affected parameters and effects are listed in Table 5.

Table 5: Local and system-wide impact categories of wind power feed-in [UCTE 2004e]

Local impacts	System-wide impacts
- Branch flows and node voltages - Protection schemes, fault currents, and switchgear ratings - Power quality (harmonic distortion[67] and flicker[68])	- Power system dynamics and stability: Grid destabilisation when wind turbines already disconnect at relatively small voltage drops. - Reactive power and voltage control: Not all wind turbines are capable of varying their reactive output. Weak coupling to the system (low output voltage and distant locations) reduces the possible contribution to voltage control. - Frequency control and load following: Due to the uncontrollable prime mover, wind turbines can hardly contribute to primary frequency regulation, while the less smooth residual load complicates load-following of conventional units[69].

4.4 Adaptability of the generation system

Different means can be applied to cope with the effects of fluctuations and the requirements resulting for the adaptability of the electricity system. These shall shortly be described in the following paragraphs. Next to the most common options to provide reserves and control power by conventional power plants, also the most important energy storage options shall be described.

4.4.1 Conventional reserve capacities

In order to be able to provide the required reserves and balancing power, the remaining power plants and especially the conventional thermal generation capacities must be sufficiently flexible. Various technical limitations in terms of load following capabilities as well as start-ups and shut-downs need to be taken into account. These limitations shall be briefly described in the following.

A number of successive steps are necessary to start up the individual components of a thermal power plant. These steps include for example the preheating of the steam

[66] A transmission bottleneck exists if it is not guaranteed that the (n-1) security criterion can be observed due to a given load flow in the grid.

[67] Variations in the voltage wave shape, which can be caused by the power electronics in variable-speed turbines.

[68] Variations of the nominal voltage (RMS voltage), which cause lighting equipment to flicker, i.e. show annoying variations of brightness. This phenomenon is especially likely to be caused by constant-speed turbines with no buffer between mechanical input and electrical output.

[69] However, the aggregated power fluctuations in the very short-term (< 1min) of a large number of wind turbines level out quite well and usually do not cause problems.

pipes and the valve casings, synchronising the generator with the grid, and gradually increasing power output to the target value. The desired power can thus only be delivered with a certain lead time from the start signal and causes heat losses due to the necessary preheating of power plant components [Fischedick 1996]. Similarly, the flue gas cleaning stages of the power plant need to be prepared for operation (cf. e.g. [EC 2005c]). This so-called start-up time is determined by the design, the production characteristics, the fuel, and the operating status of the power plant. Depending on the precedent downtime of the unit cold starts (reserve power plants or power plants after a revision), warm starts (after downtimes up to a few days, e.g. for a weekend), and hot starts (daily start-up and shut-down) are distinguished. Table 6 shows the requirements of the German grid association DVG for the start-up time of thermal power plants.

Table 6: Requirements for start-up times of thermal power plants [DVG 1991]

Plant downtime	State	Start-up time to full power (max.)
Fossil-fired steam power plants		
< 8 h	Hot	2 h
8 – 50 h	Warm	3 h
> 50 h	Cold	5 h
Nuclear power plants		
< 8 h	Zero load, hot	3 h
8 – 120 h	Zero load, hot	6 h
> 120 h	Zero load, cold, subcritical	25 h

Gas turbines have significantly shorter start-up times than steam power plants. Normally they can deliver their nominal power within 10 – 20 min, in extreme cases fast loading is possible within five minutes [Bohn 1993]. In combined-cycle units the start-up characteristics depend on the process layout. While the gas turbine part can deliver its full load rather quickly, the steam process takes some time to follow. In the case of an unfired steam process (waste heat utilisation) the comparatively low steam parameters are reached in a shorter time, taking 20 – 50 min for a warm start, and 1 - 2 hours for a cold start.

The start-up loss is defined as the heat required to reach full load operation, minus the net generated electricity output. The losses of the shut-down process can be quantified analogously. Start-up and shut-down losses amount to between 2 and 6 GJ/MW for hot and warm starts [Bohn 1985b].

A minimum operational load is necessary to ensure a stable combustion. For conventional steam power plants, this minimum load is about 35% of the nominal output. The possible load change gradient is determined by the steam raising unit, increasing the temperature too quickly must be avoided as it produces excess strain and material damage.

Power reserves[70] in load following power plants must be completely activated within 30 seconds, while 50% need to be activated within 5 seconds. These units must thus be able to cope with escalating power variations, which is enabled by throttling the steam flow via the steam valves in front of the turbine. In partial load operation this throttling causes specific heat losses of 6% in operation with sliding-pressure and 8% in constant pressure operation [Bohn 1985a].

Table 7: Operational characteristics for different power plant technologies [Lux 1999]

Plant type	$P_{Nominal}$ [MW]	P_{min}	Ramp rate	Partial load operation
Pulverised hard coal steam power plant	200 – 600	35%	4 – 6 %/min	good
Pulverised lignite steam power plant	400 – 800	35%	2 – 3 %/min	medium
Pressurised fluidised bed hard coal steam power plant	200	60%	3 – 5 %/min	medium
Gas turbine	40 – 200	55%	8 – 20 %/min	bad
Natural gas combined-cycle power plant	80 – 600	20%	8 – 10 %/min	medium
Interconnected combined-cycle power plant	300 – 700	11%	4 – 6 %/min	medium
Nuclear power plant	900 - 1300	30 – 50%	5 – 10 %/min	medium

4.4.2 Energy storage

Although only to a limited extent, electrical energy can be stored to optimise power plant and grid operation. The most common applications of electricity storage are based on mechanical energy as the stored intermediate form of energy, such as pumped storage, compressed air energy storage, and flywheels.

Energy storage facilities can take over a variety of tasks in the electricity system that are beneficial for the uptake of high shares of fluctuating electricity production (compare e.g. [Kleimaier 1998], [Crotogino 2003]):

- transformation of base load electricity to peak load electricity, reducing the need to operate other peak load capacities;
- reduced reserve of backup capacities, allowing a more efficient operation of conventional power plants due to avoided partial load operation;
- provision of reserve power (primary and secondary reserve) for an increased operational safety of the grid;

[70] 5% of the nominal load, cf. [UCPTE 1990].

- phase-shift operation, i.e. the ability to consume or deliver both active and reactive power quickly, which allows to stabilise electricity transmission and to reduce transmission losses [Bogenrieder et al. 1998, p. 236];
- management of grid bottlenecks allows to avoid or postpone investments into grid reinforcements;
- integration of renewable electricity generation into the grid is facilitated by the ability to buffer production fluctuations and enable a balanced power supply.

In the following, pumped storage as the most important energy storage option and possible alternatives to take up the increasing production peaks from wind power are described.

4.4.2.1 Pumped storage

Especially in mountainous regions hydro reservoirs, some of them with the additional option to pump water, provide excellent possibilities to level out fluctuations in electricity demand on different time scales. Depending on the cycle time of energy storage, annual, weekly, and daily storage are distinguished. Pumped storage is the most sophisticated large-scale energy storage technology [Bogenrieder et al. 1998, p. 231]. The possible storage capacity is comparatively high[71] and can be quickly deployed to provide control power. Storage and pumped storage facilities contribute crucially to frequency regulation and grid stability [Kreher 2005, p. 58]. Furthermore, they can realise many starts and stops, with only one minute between pumping and turbine operation, at a power gradient of more than 30 MW/s, and without compromising the service lifetime of the installation. Next to load following purposes pumped storage facilities can also be used for reactive power compensation to reduce transmission losses in the grid [Hartmann et al. 1987, p. 57]. A disadvantage is their dependency on topographic conditions, which naturally confines an expansion of this type of energy storage. The overall efficiencies of current pumped storage power plants vary between 75% and 80% [Bogenrieder et al. 1998, p. 231 f][72].

4.4.2.2 Other energy storage options

It can be expected that the increasing efforts necessary to balance wind power fluctuations will make energy storage more attractive, especially if it can be more economical than additional grid reinforcements. With the limited existing possibilities for pumped-storage facilities the remaining suitable options for the required storage of large amounts of energy for a comparably long duration are either chemical

[71] Small hydro power plants and barrages in rivers also possess a certain potential for storage. However, their main purpose is to utilise the energy of the flowing water, rather than energy storage [Hartmann et al. 1987, p. 56].

[72] The biggest and most modern pumped storage facility in Germany is Goldisthal (1060 MW), which started operation in 2003. Apart from the fact that pumpturbines are used instead of separate units for pumping and turbining [Hartmann et al. 1987, p.61], variable speed asynchronous machines are used [Rebhan 2002, p. 667]. This allows power and frequency control also in pumping operation, the efficiency of turbine operation can be enhanced by up to 8%.

storage, e.g. by hydrogen production via electrolysis, or mechanical storage in compressed air energy storage facilities. Although technically feasible, the hydrogen option is much less efficient both energetically and economically, and, according to current expectations (see e.g. [Ball 2006]), does not represent an economically competitive solution for the considered time horizon.

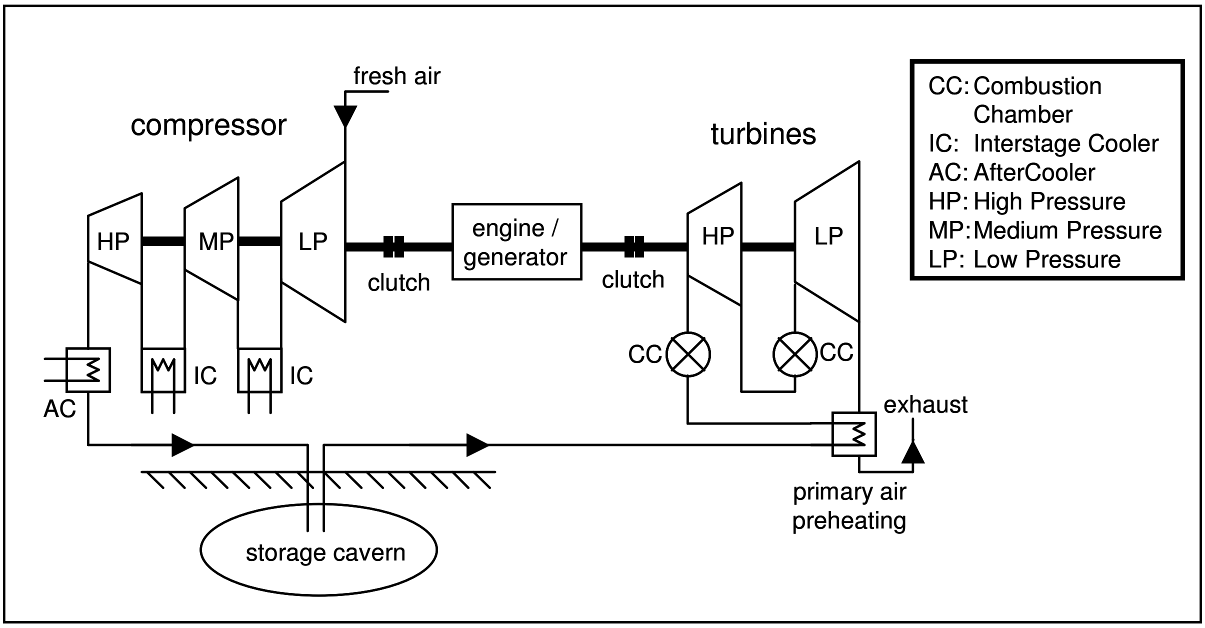

Figure 13: Flow-sheet illustration of a compressed air energy storage unit (cf. [Barth et al. 2002, p. 17])

On the other hand, compressed air energy storage is operational already today at greater technical and economic efficiencies[73]. The functional principle of this type of installation is shown in the flow sheet in Figure 13.

Compressed Air Energy Storage (CAES) plants are not energy storage facilities in the true sense of the word. In fact they are composed of a gas turbine power plant and a subsurface cavity, a so-called cavern, where compressed air can be stored[74]. This arrangement allows a temporal and spatial separation of air compression and expansion.

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[73] Other options to smooth power fluctuations - not via energy storage - are production management concepts for large wind parks with a limitation of power gradients or production caps, as e.g. described by [Rohrig 2003] and already implemented in the operation of the Horns Rev wind farm. The drawback here is that a part of economically and environmentally precious energy is wasted. Further, demand-side or so called load management measures like load shedding (see e.g. [Auer et al. 2005] or intelligent pricing approaches [Eßer et al. 2006]), can be used to provide negative reserve power.

[74] In conventional gas turbine installations usually two thirds of the turbine power are needed to run the compressor, i.e. only one third of the rated power of the turbine remains to power the electricity generator. By separating the compressor and the turbine, the entire power of the gas turbine can be utilised to run the generator, which allows to use significantly smaller gas turbines [Kentschke et al. 2003, p. 2].

Currently, only two CAES installations are operative worldwide, a few additional ones are in the planning or construction stage [75]. A combination of offshore wind parks and CAES units could be beneficial[76]. In the coastal regions of the North Sea and the Baltic Sea, numerous salt deposits allow to create salt caverns in close proximity of the planned offshore wind parks. Such a combination allows for a smaller dimensioning of transmission lines, as the storage would relieve the grid from short-term load peaks. Moreover, a better utilisation of the transmission capacity can be achieved. In light load conditions excess wind power does not have to be spilled but can be absorbed and used at a later time. Further, the necessary backup capacities for control power (between 70 – 90%) can be considerably reduced [Crotogino 2003, p. 7 f.].

4.5 Economic and ecological evaluation of RES-E integration

When evaluating the benefits of renewable electricity feed-in, firstly economic and ecological benefits can be distinguished. However, there are interrelations between these two types of benefits. Due to the emission limitations implemented and the resulting price for CO_2 emission rights under the EU-ETS, the ecological benefit of reduced CO_2 emissions will automatically also result in corresponding economic benefits. Further ecological benefits, e.g. avoided external costs, are not accounted for in today's electricity pricing, even though they can be used to assess the total economic value of renewable electricity production.

Generally, the electricity market price, and thus the economic value of conventional electricity replaced by renewable energy sources, is determined by the relationship between electricity supply and demand. However, with electricity demand responding rather inelastically to price variations, it is mainly the supply side which influences the electricity market price. In order to meet a given electricity demand, the available power production assets are scheduled in a so called merit order with ascending production costs. The last and most expensive plant in this merit order, which has to be operated to fulfill a given demand, indicates a lower boundary for the market price. The economic benefits from renewable electricity production for the power sector as a whole are thus also dependent on the general situation of electricity markets and the structure of power supply, which both are subject to change during time. In this context, the general capacity situation, such as capacity shortages or overcapacities, the predomininant power generation technologies as well as energy carrier prices

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[75] Owned by the German utility E.ON (formerly Preussen Electra), the first facility of this type with a maximum output of 290 MW exists and operates successfully since 1978 in Huntorf, Germany [Crotogino 2003, p. 6]. The second existing CAES power plant in McIntosh, Alabama, with 110 MW is in operation since 1991 and utilises the hot exhaust gases of the low pressure turbine for regenerative preheating of the pressurised air from the cavern in front of the high pressure turbine. This allows a reduction of the necessary amount of fuel by 25% [EA Technology 2004, p. 9]. In Norton, Ohio the world's largest CAES facility is planned, with a maximum output of 2.700 MW [Hirschfelder et al. 2005, p. 6].

[76] Another German utility, EnBW, has announced to invest into a new CAES facility in northern Germany [EnBW 2006].

influence the electricity price, i.e. the value of the electricity replaced by renewable energy sources. Benefits already directly influencing today's electricity generation costs are mainly related to the saved conventional fuels that do not have to be used instead. In the medium to long term, renewable electricity generation may also make conventional capacity extensions redundant to some extent. Thus, not only the short-run marginal costs, as in electricity markets characterised by sufficient available capacities, but long-run marginal costs may be increasingly influencing the value of renewable power production in the future[77].

The determination of an economic value of renewable electricity feed-in can be used as a basis for the assignment of an appropriate, i.e. an effective and efficient, fixed feed-in remuneration for RES-E generation (cf. [Krämer 2003, p. 6]). Based on the determined value of renewable electricity generation and the generation costs of renewable electricity, the remuneration, e.g. as the height of the premium in a premium system, can be chosen. This should be done in a way that gives sufficient incentives for renewable energy producers to develop additional projects, but which on the other hand avoids an excessive remuneration level, which would create windfall profits for RES-E producers.

The fluctuating feed-in of wind power and its technical implications have consequences also in an economic context. As electricity production from wind power depends on the volatile wind energy resource, utilities have to provide quickly adjustable power plants for balancing power. A number of issues and disadvantages arise for electric utilities and grid operators which have been described in more detail above:

- More extreme load situations are faced in the grid, necessitating grid extensions.
- Installed capacities of wind energy plants contribute to the secured capacity of the plant portfolio only to a small percentage, which decreases with growing wind power penetration, i.e. relatively more reserve capacities are needed.
- The less predictable residual load curve requires more frequent start-up procedures of conventional power stations and causes a decreasing efficiency (higher specific fuel consumption) due to more frequent partial load operation, and due to the increasing provision of balancing power necessary.
- Average specific production costs in the conventional plant portfolio rise (passed on to consumers as rising prices on the competitive market) as

[77] In liberalised electricity markets, power prices show a cyclical behaviour (see e.g. [Ockenfels et al. 2005], mainly dependent on whether overcapacities are existing (with marginal costs determining electricity prices) or whether there is a demand for new capacities, e.g. due to a rising electricity demand or the end of the lifetime of existing capacities, or both. In this latter case, full costs begin to influence the prices when the construction of new power plants becomes necessary. This situation can currently be observed in Germany, where up to 50.000 MW of capacity will have to be replaced in the next 10 – 20 years [Pfaffenberger et al. 2004].

workload decreases due to the required higher flexibility of power plants and the necessary reserve capacities.

Possible forecast errors of wind energy feed-in require additional reserve capacities and balancing energy. Although an improving forecast quality can be assumed for future years, the rising share of installed wind power will bring about an increased demand for balancing energy and reserve capacities[78].

Electricity generation costs are negatively affected by the above effects due to three main reasons:

In the first place the integration of wind power into the conventional plant portfolio causes changes as the workload of conventional power plants decreases and therefore leads to rising specific production costs.

Secondly, as the integration entails an increasing demand for positive and negative balancing power, the prices on the balancing energy market rise, causing on their part an increase of prices on the competitive market.

Thirdly, additional costs for the reinforcement and extension of the onshore extra high voltage transmission grid will occur. These are estimated to amount to about 0.28 billion Euros up to the year 2007, approximately 0.49 billion Euros for the period 2007 to 2010, and from the years 2010 to 2015 about 0.35 billion Euros. The grid connection of offshore plants will cost approximately 5 billion Euros up to the year 2015. Up to the year 2015 the specific costs for grid use are expected to rise by 0.025 cent/kWh [Dena 2005].

As already mentioned, the additional generating capacity of newly installed wind projects has a limited added capacity value for the overall supply system, all the more in that the capacity situation in European electricity markets has been characterised by overcapacities. Consequently, only fuel costs and other variable costs of replaced plants in operation can be avoided in the short term. These avoided electricity supply costs depend on the replaced mix of power plants (cf. [Möst et al. 2005]). Different from the case of schedulable or storable forms of electricity production, as e.g. hydro power reservoirs, the fluctuating occurrence of wind energy, which can not be actively influenced, does not provide the opportunity to shift the provision of electricity to those hours of the year where the highest power prices can be achieved. Thus, a production planning based on so called shadow costs or opportunity costs[79] cannot be realised in this case. Instead, the corresponding conventional power production replaced each time a feed-in takes place is decisive for the value that can be assigned to the wind energy feed-in. Currently, this will most commonly be power from intermediate load power plants, from which production is partly replaced. With

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78 In the German grid study [Dena 2005] it is assumed that in 2015 an additional 7,064 MW of positive balancing and reserve power will have to be provided, as well as an additional 5.6 TWh/a of positive balancing energy, compared to 2.1 TWh/a in 2003.

79 Opportunity costs are characterised by the fact that possibilities (opportunities) for a maximised utilisation of resources have not been realised.

the assumption of a perfect market, the short-term marginal generation costs of these power plants are determining the market price and thus the value of wind power feed-in[80].

However, in the medium to long term further generation capacities are needed. Thus, in the future wind capacities will be able to replace not only power production, but partly also the construction of conventional power plant capacities. In this case, the applicable value of wind energy feed-in rises from the currently purely variable cost components to the full costs of the replaced conventional generation options. Based on full costs, the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety estimates these avoided electricity supply costs for the year 2005 to be at about 4.3 cent/kWh and the avoided CO_2 emissions at 800 g CO_2/kWh [BMU 2002], without taking efficiency losses into account.

As for the future it can be expected that the coverage of intermediate load will be progressively shifted from coal to gas fired power plants, also the variable portion of the electricity costs avoided by wind power will increase as a result of the higher fuel prices. In order to quantify the effects of wind energy in the long term, several framework conditions like primary energy prices, emission ceilings, and the German case of nuclear energy phase-out have to be considered. All of the above aspects are examined more closely in the model-based analysis described in the following chapters.

80 In a strict sense, the assumption that marginal costs of the replaced electricity from thermal generation sets determine the value of renewable electricity feed-in is applicable only to perfect markets. In completely liberalised markets the power price realisable at the time of feed-in can be used instead as an index value for the determination of the value of the feed-in. A feed-in during peak load periods will in this case be assigned an accordingly higher value than in base load periods. It can also be observed that a high forecasted feed-in of renewable electricity leads to lower power prices on the day-ahead spot market (cf. e.g. [Bode et al. 2006]). Contrary to that, in a monopoly market with the objective of a minimisation of total expeditures of the power plant portfolio, the avoided costs of the thermal generation assets are relevant for the economic value of renewable electricity feed-in.

5 A hybrid modelling concept for the analysis of renewable electricity integration

In the previous chapters the various technical, economic and environmental implications of an increasing use of renewable electricity for the power system have been described. The resulting effects, in particular also those connected to an increasing scale of fluctuations in the system, need to be considered[81], both in power system operation and in long-term energy system expansion planning. Consequently, this requires the development of methodologies that enable an appropriate consideration of short- and long-term effects in energy system modelling.

Initially, an overview over the planning process in the energy sector and decision support instruments used shall be given in this chapter. Special consideration will be given to model types and methodologies for medium- to long-term energy system expansion planning and approaches for the modelling of renewable energy sources.

Further, the requirements for a modelling approach for the analysis of the role of renewable energies in European power supply are derived, with special consideration of fluctuation-based effects. Finally, the realisation of these requirements in a hybrid modelling approach is described.

5.1 Levels and tasks for utility planning

The foremost premise of electricity production is to ensure a secure supply of electricity for the consumers. Due to the practical limitations connected to the storage of large amounts of electricity and the losses associated with a transformation to other, storable forms of energy, demand and production should in principle be equal at all times. Within the planning process necessary to guarantee this supply, different time horizons (short-, medium-, and long-term) are distinguished. Figure 14 shows a more detailed classification of the planning tasks in relation to the different time horizons.

Guaranteeing a structurally adequate energy supply infrastructure with sufficient capacitites is the objective of long-term system expansion planning. The strategic planning tasks comprise mainly capacity expansions[82] or the decommissioning of active capacities, but also the treatment of other strategic questions as e.g. primary

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[81] The interaction of large-scale wind power production with the power system, including the estimation of the value of wind power in terms of secured capacity, fuel savings and CO_2-reductions, has been the subject of several studies, see e.g. [Holttinen 2004], [Nielsen et al. 1999], [Krämer 2003], [Sontow 2000], [Liik et al. 2004], [Dena 2005], [Dany 2000].

[82] Beyond the necessary new capacity also the geographical location of this capacity in relation to the available infrastructure (fuel supply, grid, cooling, etc.) is of importance for the planning process and needs to be determined. Geographical information systems (GIS) can be used to incorporate spatial parameters into the planning process. Spatially related data is also of vital importance for the cost-efficient resource planning of renewable power generation (e.g. for wind resource maps [EWEA 2003a] and the mapping of biomass potentials). For possible future key technologies like carbon dioxide capture and storage or hydrogen production this aspect will also be relevant with respect to the storage of (by-)products (cf. e.g. [Cremer 2005] and [Ball 2006]).

energy planning, or grid expansion planning as well as the possible introduction of new technologies. Such decisions, which often need to be made up to 20 or more years ahead, require forecasts of the evolution of critical parameters such as demand, maximum load, and future energy carrier prices.

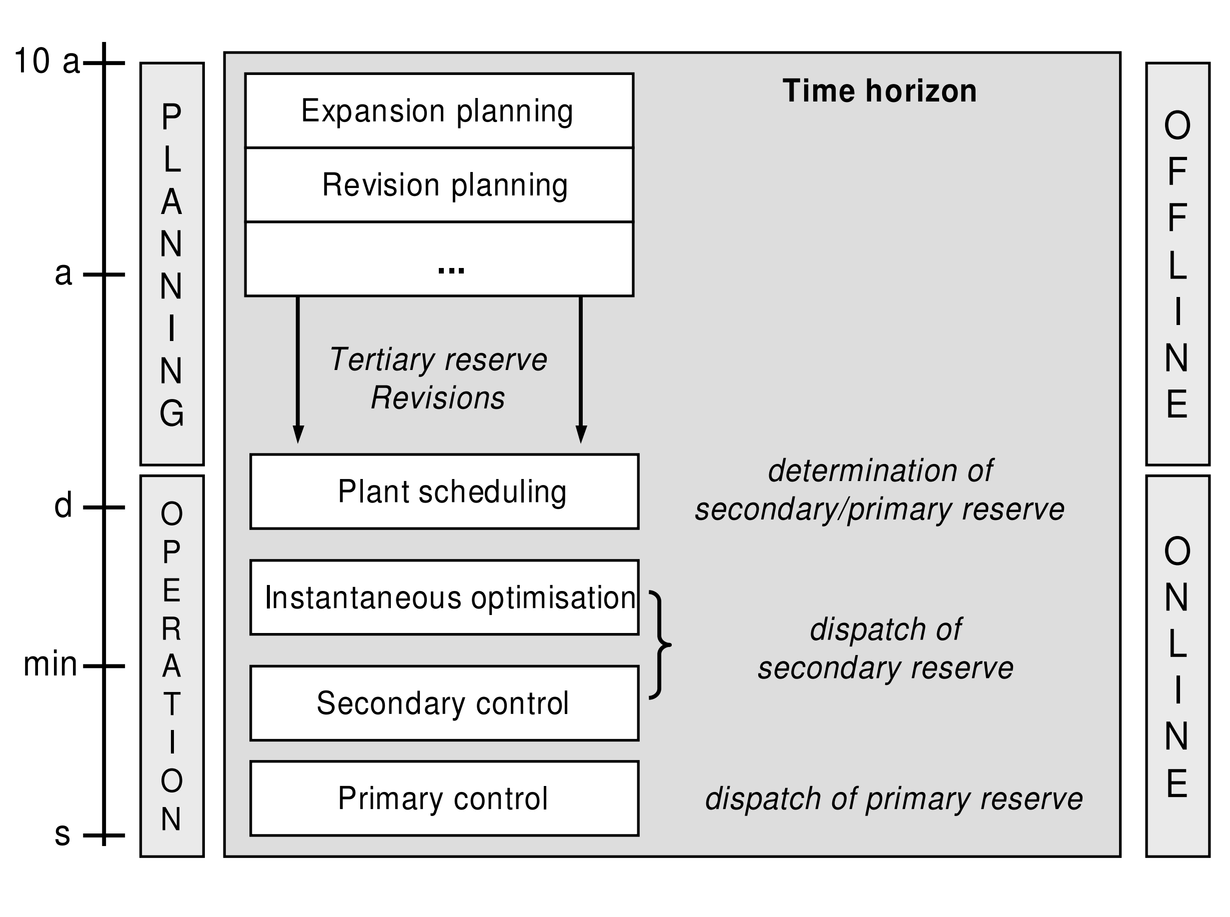

Figure 14: Utility planning levels (adapted from: [Dany 2000, p. 6], [Ameli 1997], and [Taud 1979])

As a first step of refinement in long-term planning, regular outage periods are defined in revision planning. Further medium term planning goals are the necessary fuel supply arrangements, including the optimised operation of seasonal storage volumes. On the next level of detail, in correspondence to the expected load profile for the next hours up to days ahead, the optimised production schedule is determined in capacity production planning. Here, start-ups and shut-downs of units with their respective costs, scheduled downtimes, e.g. due to the overhaul of components, and the optimisation of the daily storage volume are taken into account. Thus, in the medium term a preliminary load distribution among units, the so called power plant scheduling, is determined, which is further refined within the short-term optimisation process.

Instantaneous optimisation supports short-term production planning and scheduling by determining the profit-maximising dispatch of all currently producing generation units[83], while having to respect system reliability criteria and delivering the necessary ancillary services. Another result of instantaneous optimisation is thus also an optimal utilisation of the grid and the resulting reactive power losses, as well as the technical limits of transmission capacity.

Planning on the different levels can interfere with the planning processes on other levels. If, for example, the actual load distribution differs from the scheduled dispatch of the units, the long-term energy planning has to be recalculated[84].

In order to carry out the complex and interconnected planning tasks delineated above, systematic decision support is required, which needs to reduce the complexity of the real life systems to simpler structures. In general, such a system modelling process can be defined as a purpose-oriented simplification of reality by means of abstraction [Marquardt 1995, p. 10], i.e. only those characteristics of the original system which are interesting with respect to this purpose are selectively represented in the model[85]. Thus, within the process of modelling it is necessary to acquire profound knowledge about a certain subject in order to identify and adopt only those facts for the model that are essential for the solution of the treated task (cf. [Marquardt 1995, p. 10]), i.e. which allow to reliably predict system behaviour even in an easy to handle model structure with a limited number of parameters. General classifications of models can be found e.g. in [Dyckhoff 1994], and [Penkuhn 1997], a generalised description of the process of model formulation and development is e.g. given in [Marquardt 1995].

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83 For these interrelated tasks a multitude of approaches exists, which can on the one hand be differentiated into heuristic and mathematically exact methodologies, and on the other hand into long- and short-term models. While for heuristic methods the optimality of the solution cannot be guaranteed, they are characterised by comparably low calculation times and a high flexibility [Ameli 1997], as e.g. the formation of the merit order (sequential operation of power plants according to their specific generation costs). Enhancements are fuzzy logic approaches, artificial neural networks and genetic algorithms. In contrast, mathematical approaches can guarantee optimality, as the whole solution space is scanned. Two groups of methodologies exist, either generating a consistent solution (e.g. mixed-integer linear programming) or using a decomposition of the optimisation problem, where partial problems (e.g. the decision to use a block and the decision about its load/output) are solved separately in order to reduce overall complexity. Widely-used approaches are dynamic optimisation, Lagrange relaxation, as well as a variant of mixed-integer linear programming. For day-ahead scheduling Lagrange relaxation is regarded to be suited best and also used most frequently [Hobbs et al. 2001]. An overview of the different methodologies can be found e.g. in [Ardone 2001] and [Hobbs et al. 2001]. A method with a consistent solution is mixed-integer linear programming (MILP). The major drawback of this method are the long calculation times needed (exponential complexity).

84 Further planning restrictions, which have to be observed in generation planning, result from the electricity grid. While some production planning models also feature an integrated, relatively simple DC model of the grid, specialised electrotechnical models are usually used to determine the load flows and check the compliance with the n-1 security criterion within the grid.

85 In other words: ‘To an observer B an object M is a model of an object A to the extent that B can use M to answer questions that interest him about A’ [Minsky 1965]. Thus, not necessarily only one model of an object exists, but rather model variants/versions, which are distinguished by the intended use, the knowledge about the modelled object, the experience of the modeller, and the necessary or acceptable level of detail (cf. [Marquardt 1995, p. 7]).

Most sub-problems in the process of energy system planning can be solved by means of models, with the solutions of all sub-problems integrating to the solution of the complete planning problem. Numerous models specifically designed for decision support in the energy sector have been applied especially by energy utilities and in political decision making for a variety of different planning tasks (see e.g. [Fichtner 1999]). In the following sections, a condensed overview shall be given over the scope of approaches and tools that have been developed to assist in decision support for long-term capacity planning, RES-E market penetration, and the evaluation of effects from fluctuating electricity production.

5.2 Existing approaches for decision support in capacity expansion planning

Planning models are employed for systematic decision support in all of the aforementioned planning stages (see Figure 14). Their methodologies are adapted to reflect the tasks and peculiarities of the respective planning stage[86]. Descriptions of existing approaches, in particular also for long-term investment planning[87], for the different planning tasks of utilities can e.g. be found in [Lüth 1997, p. 9 ff.], [Wietschel 2000, p. 120 ff.] and [Graeber 2002, p. 30 ff.].

Generally it can be observed (cf. also [Verstege et al. 1997], [Göbelt 2001]) that comparatively fewer decision support instruments in investment and production planning are used, while their application in short-term planning stages is much more frequent. A possible reason for this fact can be seen in the overcapacities that existed in the non-liberalised market. These probably led to a reduced necessity for the analysis of requirements and perspectives connected to the development of long-term planning strategies for power plant investments in the liberalised electricity market.

Different attempts to classify energy system modelling approaches can be found in literature (e.g. [Bunn et al. 1997a], [IEA 1998a] [Henning 1999, p. 26 ff], [Vögele 2000, p. 37 ff.], [MEX II 2002, p. 27 ff.]). A common classification of models for electricity sector planning distinguishes between Bottom-Up models on the one hand, and so-called Top-Down models on the other. While Top-Down models are characterised by an integral approach considering the entire national economy on a high level of aggregation, Bottom-Up models employ a process analytical approach, i.e. they provide a differentiated analysis of technological options on the micro-economic level, while Top-Down models are based on highly aggregated growth models, composed of different sectors. As a result of the changed market environment of liberalised electricity markets, electric utilities are able to operate their power plants as profit centers, depending on the electricity price an the merit order of

86 A broad spectrum of applications is described in more detail e.g. in [VDI 1997], [VDI 2001], [VDI 2003], [VDI 2005].

87 In the power sector such approaches are commonly referred to as capacity expansion models.

their plant portfolio. New modelling approaches are developed which intend to reflect this aspect and the possible strategic behaviour of market participants (cf. e.g. the multi-agent approach described in [Fichtner et al. 2003] and [Genoese et al. 2005].

A classification and an assessment of energy system models specifically for long-term electricity sector analyses is e.g. given in [Enzensberger 2003, p. 42 ff.].

5.3 Existing approaches with a focus on renewable power production

In the existing energy system models described above, renewable power production and the associated potentials are in most cases not part of the optimisation. Instead, fixed expansion paths are commonly used to assess different expansion scenarios. One of the reasons for this practice is that the representation of individual RES-E potentials and their costs is connected to comparatively extensive efforts in terms of modelling and data gathering. Due to the hitherto low penetration and the minor relevance for the electricity sector as a whole, these efforts did not pay at all or were worthwile only to a limited extent.

For low penetration rates the resulting biases in the model are small in relation to the whole power sector and thus acceptable. However, the currently observed and politically further fostered increase of the penetration of renewable energy carriers with high shares of fluctuating generation lead to increased deficits for an appropriate representation in energy sector planning models, which makes an improved representation of fluctuating renewable power production desirable. Further, in order to be able to assess the effectiveness of promotion instruments for the use of renewable electricity, these also need to be integrated into the existing modelling approaches.

5.3.1 Market simulations based on cost-resource curves

Along with the stipulation of goals for renewable electricity utilisation and the introduction of according policy approaches for the promotion of RES-E expansion, a necessity to assess the feasibility of these targets and the incentives associated with the different promotion policies in a more detailed way arose for the first time. As a result of this necessity, a number of economically oriented modelling approaches were developed, which in a detailed way simulate the market entry of renewable energies under different framework conditions. Mostly, the approaches rely on market simulations, which are based on the balancing of supply and demand curves. While the supply curves on the one hand can be derived from the available potentials of individual renewable electricity generation options and their costs, the demand for renewable electricity on the other hand is determined from the electricity price and the price incentives given by the incentive schemes. Partly, the approaches are dynamic and take into account intertemporal relations, as e.g. the evolution of incentive schemes or cost decreases as a result of learning effects. In the following, some of these dedicated approaches will shortly be introduced and outlined.

One example for a dynamic simulation of the renewable electricity market in the EU is the ADMIRE REBUS model (cf. [Uyterlinde et al. 2003]). Its approach is based on the static simulation methodologies of the REBUS[88] [Voogt et al. 2001] and ElGreen [Haas et al. 2001b] models. Both REBUS and ElGreen use national static marginal supply cost curves to simulate an ideal TGC market. These curves indicate the correlation between the price of electricity and the amount of electricity produced from a given source and are derived from estimates of different RES-E potentials, their costs and expected performance. A similar approach as in ADMIRE REBUS is used in the Green-X model [Huber et al. 2004] and the GreenNet model [Obersteiner et al. 2006]. As the ADMIRE REBUS model, these models takes into account fully dynamic cost-resource curves, i.e. the potential and the cost of each renewable energy technology are determined endogenously in the model, depending on the one hand on the static cost-resource curves, and on the other hand on the outcome of the previously simulated year as well as the policy framework conditions set for the simulation year. In the case of the GreenNet model, special regard is given to the costs for the grid integration of renewable energy sources and various scenarios for their allocation.

All of these models have in common that the electricity commodity price development is an exogenous model input[89], which can be varied in scenarios. Interactions with the electricity and CO_2 market can thus not be considered directly in the simulation models.

5.3.2 Model-based approaches for the analysis of effects from fluctuating electricity production

In order to integrate an increasing feed-in of wind energy or other sources with a variable output into planning models, these must be designed to consider the technical implications of the fluctuating nature of wind power as well as the limited predictability of the power delivery. Several authors have developed model-based approaches to take into account these special characteristics of wind energy. A short comparative summary of their findings shall be given in the following.

[Leonhard et al. 2002] base their model for the northern German area on the assumption that the preferential feed-in of wind energy displaces power production from conventional power plants, where fuel consumption and emissions are mitigated as a consequence. They assume that primarily coal- and gas-fired power plants have to absorb the compensation of the wind power load profile. Due to the displacement of the operating profiles towards operation at partial load the energy related (specific) fuel consumption and thus also the CO_2 emissions per kWh produced rise in the conventional power plants. The intention of their control-theoretic modelling approach is to quantify the losses due to this balancing action in an exemplary area of the grid.

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[88] **R**enewable **E**lectricity **BU**rden **S**haring.
[89] In the case of the GreenNet model, the exogenously given price development results from a stochastic fundamental electricity market model.

For the one-week load profile that was simulated the amount of fuel saved in the conventional power plants was 72% of the theoretically possible savings[90].

[Fischedick 1996] examines the 'increased contribution of renewable energies and of combined heat and power plants to power supply'. In his analysis, he considers the changed requirements for conventional power plant operation due to the fluctuating nature of power production from photovoltaics, wind power, and combined heat and power plants. The approach considers the above fluctuating power production as a reduction of the residual load that remains to be covered by the conventional power plants, but which exhibits a different profile than the original load.

Thus, three different models are used: one for the determination of the consequences caused by fluctuating power production, a revision planning tool, and a power plant scheduling tool. Each of these models is applied in an exemplary case for a reference system with a proportionate supply task.

Model results show a substitution of intermediate and peak load power plants by wind, photovoltaics, and CHP. While conventional generation with high variable costs is thus replaced, higher operational demands occur due to more frequent start-ups and shut-downs of plants. With increasing shares of wind, PV and CHP the above applies also to base load units. While fuel consumption and CO_2 emissions decrease, total costs increase nevertheless. Moreover, the existing power plant portfolio can hardly meet the balancing requirements caused by the increasing share of fluctuating production. Thus, power plants with good balancing characteristics, i.e. with low minimum loads, good partial load performance, low start-up losses and high load variation rates are the favourite choice for newly added capacities.

[Lux 1999] assumes that the operating characteristics of conventional power plants will change substantially as a consequence of high shares of fluctuating power production. In his model he chooses a time horizon of one year and a high temporal resolution of 15 minutes for selected time periods. A revision planning is carried out and the production characteristics of conventional power plants is determined. The revision planning is conducted with a problem-adequate branch-and-bound algorithm, while the production planning is based on a mixed-integer linear optimisation approach.

For the quantification of the effects of wind power generation on the conventional power plant portfolio a reference case is defined, where the coverage of the electricity demand is entirely met by conventional power production. For comparison, different penetrations of wind power production are considered.

[90] Own calculations with a control theoretic approach for the modelling of a sample power plant portfolio of the same composition as the German electricity generation mix indicated higher effective fuel savings of about 85% of the theoretical maximum savings.

Revision planning is neither monetarily nor structurally (revision times) affected in a noteworthy way, while the production schedule changes more substantially: base load power plants start up more often and the frequency of load changes doubles.

About 80-90% of the generated wind power substitutes electricity generation from hard coal, where the number of start-ups triples and the load changes double when compared to the reference scenario. In total, the fuel use is diminished, but the variable and total costs are higher than in the reference case.

The model-based analysis by [Krämer 2003] for an optimised power generation at high feed-in rates of wind energy also examines the consequences of high wind power shares on the generation system. His approach allows the power system to structurally adapt in an optimal way to a given high feed-in of wind power, using a cost-minimising linear optimisation approach. The optimisation period is one year with an hourly temporal resolution. Different from [Lux 1999] he concludes that a high share of wind power production also displaces base load power plants, as a high feed-in of wind power limits the constant base in the residual load curve. While the fluctuations necessitate a constant provision of additional control power, he does not see a remarkable increase of total costs in conventional generation. In a scenario with high gas prices and a CO_2 tax, total costs are even affected positively. Further, Krämer argues that at a high wind share, the use of hard coal power plants can be continued on a higher level despite Kyoto CO_2 mitigation targets. Without the increased wind energy use induced by the German feed-in law, natural gas would be dominating the electricity generation mix.

The model results achieved and described by [Sontow 2000] show that 80 - 90% of the conventional power displaced by wind energy is from hard coal fired intermediate load power stations. Further, the differences in the frequency of start-up procedures due to wind energy penetration are examined. At a penetration rate of 10% no significant change is noted, at a penetration of 20% up to a triplication of start-up procedures is observed.

Using a specifically developed simulation approach, Dany [Dany 2000] quantifies the changing requirements for power plant reserves at high wind energy penetration rates. The simulation allows to estimate the necessary size and the dynamics of the different types of reserve in a system operation which is characterised by stochastic influences due to wind availability, power plant failures, and the load profile.

In the German grid study [Dena 2005], a thorough analysis of the German grid and power plant portfolio is carried out with regard to their adaptability to growing onshore and offshore wind power generation. Based on expansion paths for the utilisation of renewable electricity until 2015, the additional costs due to grid reinforcements and feed-in tariffs are determined. Future bottlenecks in the German grid are identified using a detailed dynamic model of the UCTE grid. The results indicate that in order to integrate the planned share of 20% of renewable electricity it is necessary to reinforce and extend the existing grid by about 5% (392 km of reinforcements and

850 km of new lines). Moreover, the necessary conventional reserve capacities and balancing energy are assessed. With an estimated power production of about 77 TWh from wind energy and an installed total wind turbine capacity of 36 GW, up to 7 GW of additional positive tertiary reserves and 5.5 GW of additional negative tertiary reserves are necessary in the year 2015,

In [Holttinen 2004] the technical and economic impacts of an increased wind power feed-in on the Nordic electricity system are studied. An increased demand for operating reserves is found. It amounts to about 2% of wind turbine capacities at a 10% penetration rate and occurs mainly in the time range between 15 min and 60 min. As a result, costs for balancing energy increase by 1 €/MWh for the above penetration rate. At the same time, a reduction of Nordpool spot market prices by about 2 €/MWh for each 10 TWh/a of wind power production are observed.

[Brand et al. 2005] use a stochastic energy market model to determine the value of increased future intermittent wind power shares in Germany on an hourly basis by optimising the commitment of power generation units under technical constraints. As the model does not allow for an intertemporal capacity planning, the capacity mix for future periods is provided exogenously. Depending on the season of the year, wind power feed-in can be attributed savings between 0.95 cent/kWh and 1.9 cent/kWh in the electricity system of the year 2020. Further, with Germany divided into three grid zones, they identify grid transmission capacities between the northern and central/southern regions as a limiting factor for the possible benefits of wind power integration.

5.4 Specifications for a modelling approach to analyse increasing renewable electricity generation

The approach to be developed shall be able to represent all characteristic aspects related to the utilisation of renewable electricity sources - market mechanisms as well as technological characteristics. This includes an adequately differentiated representation of the temporally and spatially inhomogenously distributed availability of the potentials, the different national regulations and the EU policy framework, as well as the possibility to represent fluctuation induced interactions with the conventional power plant portfolio in the necessary high temporal resolution. From the previous chapters it has become obvious that effects on different time scales - from one hour or less up to several years - must be considered to appropriately reflect the peculiarities of increasing shares of renewable power generation in the context of long-term electricity system planning. Moreover, influences with more or less regular profiles, like the electricity demand, as well as such of stochastic nature, like the wind energy fluctuations, must be taken into account.

Long-term energy system models often account for the utilisation of renewable potentials merely in terms of pre-defined expansion paths, or if renewables are part of the optimisation, rather highly aggregated cost-resource curves are used[91].

Furthermore, many of the described model-based simulation or optimisation approaches, even those explicitly developed for a detailed analysis of renewable electricity evolution, neglect the interactions with conventional power production. While this is acceptable for low shares of fluctuating renewable electricity generation these interactions become more and more significant at higher penetration rates.

For those approaches that explicitly investigate the interaction of fluctuating wind power feed-in with conventional electricity generation it can be argued[92] that they often merely consider the absorption of wind power in current, base load dominated electricity systems. As the system structure will not be static in the medium to long term, this results in a biased view of the effects in the conventional power system.

Thus, apart from the mid-term cost resource curves for RES-E in the EU-15 and the different options for RES-E targets and promotion policies, the planning methodology to be developed shall be able to incorporate the following features in an integrative approach:

- easy adaptability to changed framework conditions, as e.g. CO_2 restrictions, RES-E targets, or primary energy carrier price developments;
- a simultaneous consideration of production planning and capacity expansion planning;
- the consideration of technical restrictions resulting from the physical characteristics of the energy system;
- the integration of seasonal load profiles, and
- a reasonable trade-off between modelling precision and modelling effort in terms of calculation time and the requirements for RAM storage.

While for the time horizon of the model, the available mid-term potentials for renewable electricity generation shall be taken into account in a detailed way, also the effects induced by the random fluctuations of the fastest growing renewable energy source wind, which affect the long-term integrated capacity expansion and production planning, shall be taken into account.

Next to the long- and short-term interactions with conventional power plants, as e.g. the secured capacity, the necessary reserves, and balancing power, also the interaction with relevant other energy policy instruments, shall be integrated. In this case this is the CO_2 emission trading scheme, which necessitates an endogenous modelling of the certificate trading scheme.

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91 As e.g. a cumulated European renewable electricity supply curve in [Dreher 2001], or aggregated country- and technology-specific supply curves in [Enzensberger 2003].

92 This argumentation is e.g. also brought forward by [Krämer 2003, p. 14].

5.5 Realisation of the modelling concept

Due to the necessary level of detail, especially with regard to the interactions with conventional power production, top-down models with their aggregated point of view are less suitable for the analysis of the medium- to long-term role of renewable electricity production than sector specific bottom-up models, which are preferable in this case. On the other end of the scale, pure engineering models, which mostly are targeted at a detailed consideration of individual and often isolated subsystems, as e.g. the modelling of load flows in the grid or power plant scheduling, typically do not allow for the necessary integrated techno-economic view.

A hybrid approach[93] is chosen to integrate the requirements defined above into a comprehensive methodology. The approach consists of two coupled complementary modelling approaches:

1. A linear optimisation model for the analysis of long-term energy sector developments.
2. A temporally highly resolved simulation model for the heuristic determination of effects caused by fluctuating wind energy feed-in.

For the long-term energy system optimisation, which forms the basis for the assessment of the contribution of renewables and the realisation of available mid-term potentials, models are favourable that integrate production planning with system capacity expansion planning. As the long-term model approaches necessary for this task are limited in terms of their temporal resolution, they are not suitable to endogenously represent the irregularly structured and randomly fluctuating wind power feed-in, which can only be adequately represented within a temporally highly resolved model.

For an adequate description of these coherences the model for simultaneous investment and production planning is thus expanded to consider the representation of short-term power fluctuations and their effects on decisions of both production scheduling and capacity expansion planning.

To do so the structure of the power plant portfolio from the investment and production planning component is transferred into the simulation model and amended by parameters relevant for the representation of short-term plant dispatch, as e.g. load changes, fuel consumption, efficiency as a function of load, and the frequency as well as the duration of the operation of the different plant types. As further input parameters the temporal variation of the cumulated demand as well as different time

[93] The term ‘hybrid model’ is also commonly used for an endogenous combination of existing energy sector models on the one hand with highly aggregated macroeconomic models taking into account interdependencies between different economic sectors on the other hand, (cf. e.g. [Enzensberger 2003, p. 54]). While also this model combination is possible and has been realised for the French energy system in collaboration with the Bremer Energie Institut (cf. [Pfaffenberger et al. 2005]), the term will in the following be used to describe a coupling of a temporally highly resolved simulation model with a long-term optimizing energy system model.

series of wind power feed-in, both for the duration of one year, are required. As in reality the exact values of these time series are not known in advance when the power plant scheduling is carried out, its values enter the heuristic scheduling approach of base, intermediate, and peak load power plants with a prediction error, which increases for longer forecast horizons. The remaining load differences are compensated by the provision of reserves from conventional power plants and pumped storage reservoirs (compare also [Krämer 2003]).

Along with these detailed technical coherences, also economic and ecological characeristics are taken into account in the form of load-dependent variable costs and emissions, which subsequently allow an evaluation of the plant operation with regard to these aspects. Additionally, this approach offers the possibility to evaluate the quality of the forecasted load curve or the feed-in of wind power with regard to their effects on the economics and the ecological balance of power plant operation. The effects and restrictions of power plant operation additionally observed in this short-term model, as well as the adjustment of bottlenecks in the capacity structure, which can not be represented in the optimising investment and production planning model, are utilised as feedback information for a better depiction of the energy system in the long-term model. This proceeding is aimed at facilitating a detailed representation of wind power and balancing technologies for an adequate consideration of the influence of short-term effects. This is realised in an iterative procedure by determining the additional restrictions to power plant operation from the short-term analysis for each period of the long-term model and subsequently integrating them as intertemporally considered restrictions in the long-term model.

In order to obtain the characteristics of the present and the expected future electricity production from wind turbines with significant influence on conventional power production - including power variation, maximum and minimum power, and probability functions for power variations - wind speed data time series with an hourly resolution from different locations are used to calculate electricity production over time[94]. For both Germany and Spain, the countries with the highest growth of wind energy in the EU-15, sets of aggregated feed-in data time series were available. The aggregated wind power feed-in time series used as input for the simulation model are derived from primary wind speed measurements at characteristic sites and additionally taking into account the frequency distribution of the characteristic sites and the shares of different types of converter systems used at each site (cf. [Sensfuß et al. 2003]).

Both models can be used independently from each other, while their combined utilisation, the general principle of which is shown in Figure 15, allows to adequately account for the effects of large shares of fluctuating electricity production in long-

[94] While AEOLIUS is also capable of deriving wind energy feed-in time series directly from wind speed time series at different locations, aggregated feed-in time series as obtained from a wind power feed-in modeling tool developed and described by [Sensfuß et al. 2003] could be used as a direct input to AEOLIUS.

term, interregional strategic energy system planning. The main intended results to be attained are the following:

- renewable technology mix, conventional fuel-mix, development of capacities [MW], realised potentials [GWh/a], and costs [cent/kWh] in dependence of renewable energy promotion schemes and other energy system framework conditions;
- influence of a large-scale integration of renewables on the scheduling of conventional power production (power production [GWh], power plant operation [h/a]);
- marginal costs of power production [cent/kWh], capacity- and cost-effects due to stand-by capacities, reserves, and balancing power;
- regional power exchange balances, imports and exports [TWh/a];
- emissions [kt CO_2/a] and net CO_2-reductions [%].

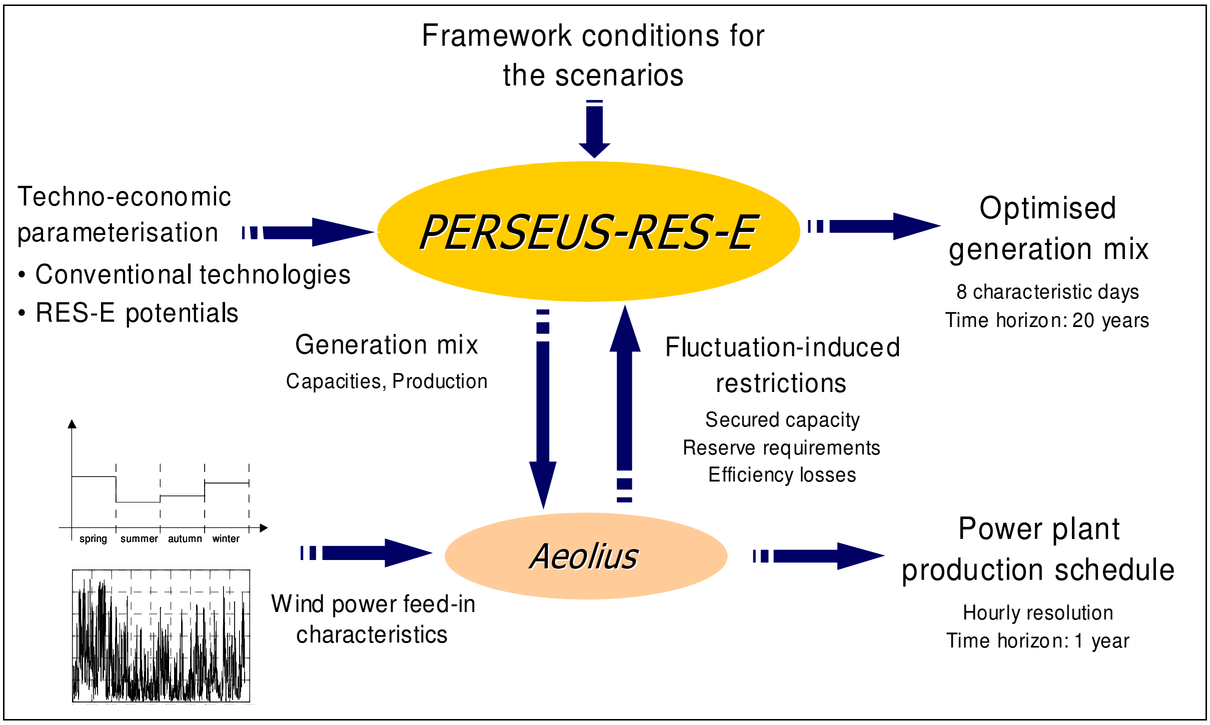

Figure 15: Functions and interaction of the long-term optimisation and the short-term simulation

The main results of the long-term PERSEUS-RES-E model are the optimised energy system structure and operation on a long-term basis (typically about 20 - 30 years), while the results of the AEOLIUS fluctuation model give information about energy system operation on a short-term basis (typically one year).

In an effort to combine the strengths and to avoid the shortcomings of many existing modelling approaches, the described hybrid modelling approach with PERSEUS-RES-E and AEOLIUS allows to take into account the structural development of the

European power plant portfolio when determining the effects of wind power feed-in. The approach also allows to include the influences of various framework conditions on the structural changes of the electricity system, as for example the CO_2 emission trading scheme. It thus allows to judge how well not only the existing, but especially the cost-optimised future compositions of the conventional power plant portfolio will be able to cope with increasing wind power production.

In the following two chapters, a detailed description of both modelling approaches and their respective methodologies is given. The development of the short-term simulation model and its analysis options shall be described first. Subsequently, the development of the long-term optimising energy system model PERSEUS-RES-E and the integration of the restrictions from the short-term model are presented.

6 Simulation of fluctuating renewable power production

6.1 Outline of the developed AEOLIUS dynamic simulation model

The AEOLIUS model was designed to simulate the combined medium- and short-term production planning for the entire power plant portfolio in a grid-area or a country, with the ability to account for an increasing feed-in of fluctuating renewable electricity generation. The major objective of the modeling approach described in the following is to provide information about the static performance issues[95] arising from the interaction of wind power fluctuations with the production schedule of conventional power plants and also with long-term strategic capacity and production planning[96]. The approach chosen is based on a simulation which employs a heuristic procedure for power plant scheduling. Two model versions have been implemented for the countries with the strongest growth in wind energy use, one for the German power sector and one for Spain. For both countries, the power sector is simulated for the duration of one year. Under the current market regulations, power plant schedules have to be announced 24 hours in advance, also called day-ahead scheduling. Beyond this, the model allows the introduction of short-term, intra-day forecasts with a better forecast quality due to the shorter forecast horizon.

To ensure an economically and ecologically optimised integration of fluctuating renewable power generation, especially wind power, a detailed characterisation of fluctuation-induced effects on the existing power system is required. A novel approach to comprehensively analyse the impact of these effects on power plant scheduling as well as to develop strategies for an optimised evolution of the power system structure has been taken. It resulted in the construction of the simulation tool AEOLIUS, which has been developed using the MATLAB/Simulink® platform [Mathworks 2001]. As described in the previous chapter, it is used in combination with the multi-periodic optimising energy system model PERSEUS-RES-E for the combined and comprehensive analysis of long- and short-term effects (cf. [Rosen et al. 2003], [Rosen et al. 2005b], [Rosen et al. 2005a]).

The primary focus of the analysis with the AEOLIUS model are the challenges for conventional power plant scheduling occurring on a small time scale of 1 hour down to 10 minutes. In this model the provision of stand-by capacities and control power from renewable and conventional capacities, as well as intermediate storage are

95 While acknowledging the great importance of dynamic aspects, as e.g. grid stability issues, these are not in the focus of the described model. The analysis of this latter subject area is the strength and focus of models for static or dynamic load flow simulations, as e.g. the model NETOMAC, which is used in the German grid study [Dena 2005]. The results provided by the AEOLIUS model are obtained under the premise that the dynamic issues can be resolved in an adequate manner.

96 With the intention to quantify the actual effects of wind power fluctuations on the power system and under the premise that for the future it is desirable that each (national) power system should be able to compensate for the effects of its own fluctuating wind power feed-in, the power exchange with neighbouring systems is not taken into account for the compensation of fluctuations.

covered in detail. Thus, a sophisticated quantification of the benefits and also the limiting effects of wind power feed-in can be achieved.

The basic model structure and components can be visualised as shown in Figure 16 below. In the following, the structure of the model will be described and its implementation exemplified for the German power sector.

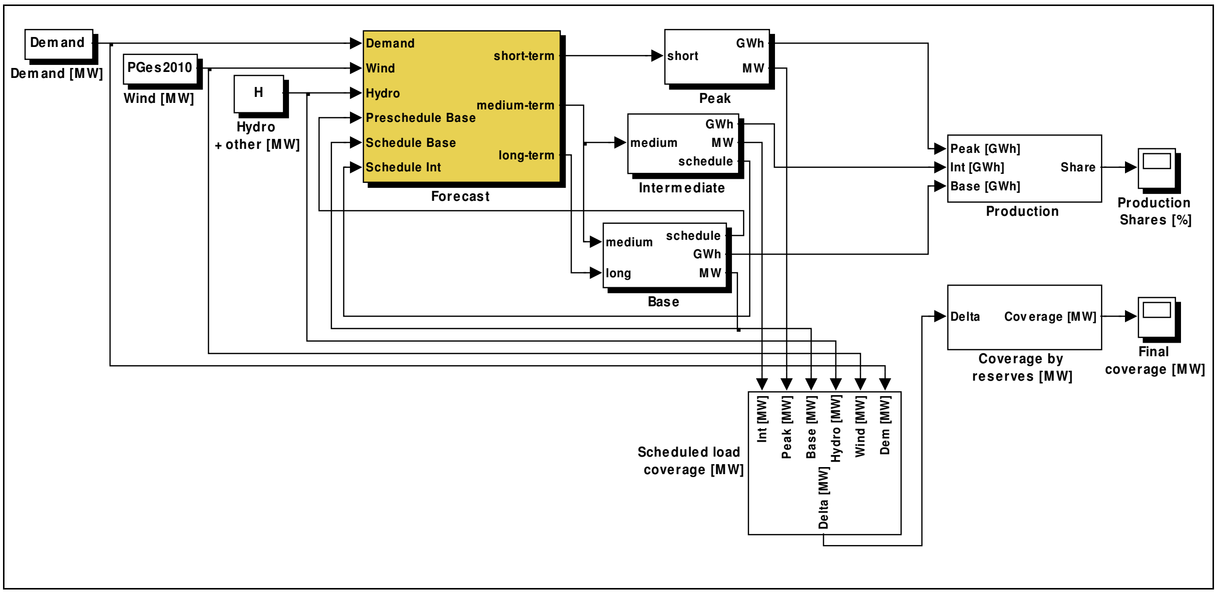

Figure 16: Basic structure of the AEOLIUS model in Simulink

The model has been implemented as a graphically oriented Simulink flow-sheet and a version purely relying on MATLAB code, only using the visualisation of results possible with Simulink. Whereas the original flow-sheet version is slower and less flexible when it needs to be adapted to a changed structure of the energy system, it gives a good overview over the functionality of the model. The code based version allows an automated import of energy system parameters from Excel files and thus offers more flexibility when the underlying system needs to be amended or changed. This import feature is especially advantageous with regard to the data transfer necessary for the soft-link with the long-term PERSEUS-RES-E model. In addition to the parameters of the current electricity sector it allows for a facilitated definition of future electricity generation structures in the short-term AEOLIUS model.

The modelling of the different plant types was conducted with the aim of maintaining an adequate level of technical detail. Thus, stochastic plant failures, start-up and load-change characteristics, as well as partial load operation, were included.

Figure 17 shows a rough overview of the simulation process with AEOLIUS. The driving force of the model is the load interpolated from hourly UCTE-data [UCTE 2003]. The corresponding load characteristic is depicted as a Simulink signal in the upper right of Figure 17. A portion of the total electricity demand is covered by the feed-in of hydro and wind power. The residual load, which remains to be covered by conventional and other renewable electricity sources, is represented by the Simulink signal in the middle. Based on this profile, load forecast simulations are done by multiplying each value of the profile with a Gaussian noise. Taking into account the block availability, i.e. the fact that blocks are unavailable in the case of either a stochastic plant failure or a scheduled revision, a production schedule for each plant and cumulated for all plants is produced. This is graphically shown in the lower right Simulink signal in Figure 17. The resulting costs and emissions are computed and shown along with further calculations and results. For the determination of plant schedules the variable power production costs are taken to compose a merit-order of plants. Based on this ranking, the load profile, and the reserve requirements for each hour of the year it is decided which blocks are run, and at what load. For the scheduling all technical restrictions, as e.g. start-up times or minimum times of operation and standstill, are considered. Scheduling is done on three different time-horizons, which are based on long-term (24 hours), medium-term (4 hours), and short-term (1 hour) forecasts. They are used in this order to schedule base load, intermediate load, and peak load capacities. The simulation of forecasts and the necessary reserve capacities are described in greater detail in the following paragraphs.

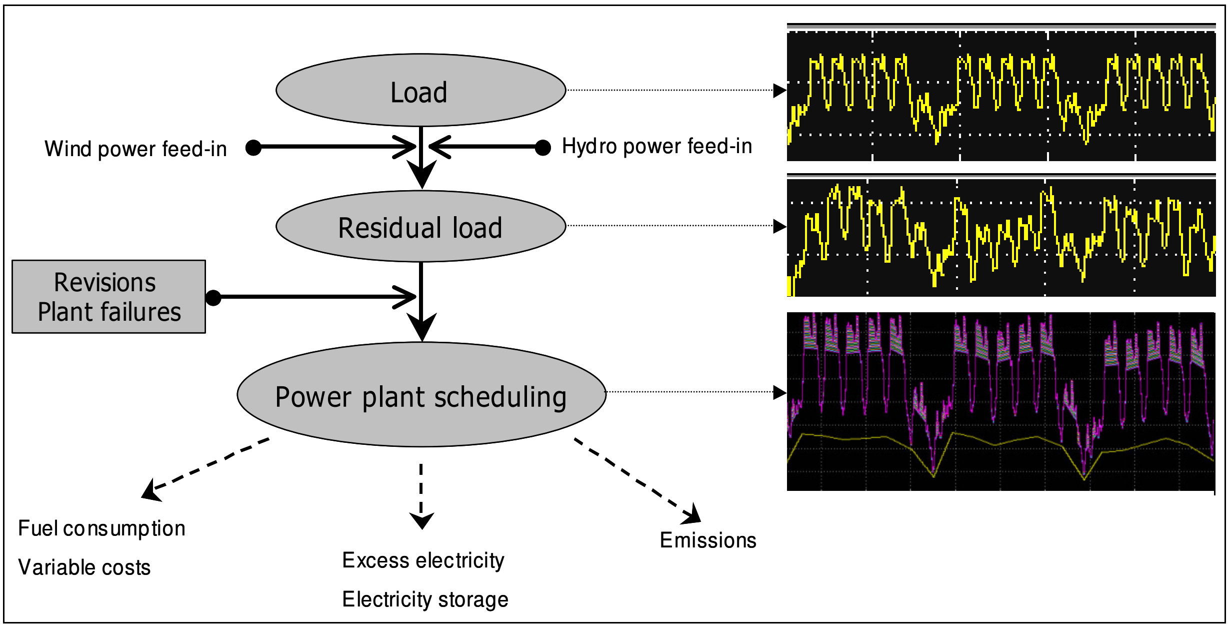

Figure 17: Schematic overview of the AEOLIUS modelling approach

Before that, a short introduction to the program structure and functionality shall be given. After reading all plant- and fuel-specific parameters as well as the profiles for load and wind power feed-in from Excel files, statistic parameters are calculated, e.g. the hourly fluctuation of wind power, which is later used for other calculations. After completion of the simulation results are made available for graphical and numerical analyses and are moreover documented in a textfile.

6.2 Exogenous input data

The principal input to the model, which acts as the driver for power generation in the modelled power plants, consists of the hourly mean values for total electricity demand. This input is provided for each of the 8760 hours of a year. Appropriate values can be derived from the demand statistics of the UCTE (e.g. [UCTE 2003]). For each month the weekdays are represented by the data given for the third Wednesday of that month, while the Saturdays and Sundays of each month are represented by the according data for two characteristic weekend days of the same month. This data can automatically be read into the MATLAB workspace from an Excel sheet for use in the Simulink model, allowing for an easy provision of current and expected future demand data to the model.

The second endogenous variable of crucial importance for the model is the total feed-in of renewable electricity. The amount of feed-in determines how much of the original total demand remains to be covered by conventional power plants, this remainder being called the residual demand.

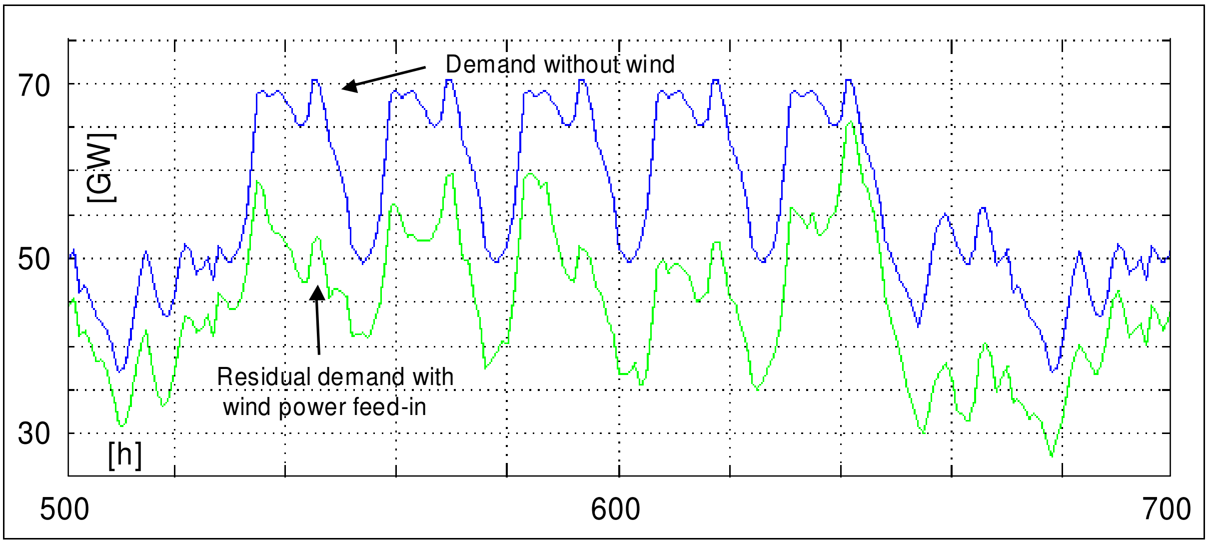

Figure 18: 200 hours time series of electricity demand and residual load with wind power feed-in

Especially interesting in the context of production planning is the amount of fluctuating feed-in, which cannot be planned beforehand. Instead, these fluctuations occur in a random pattern and have to be compensated by the production of the conventional capacities in the power system. This effect is most pronounced for wind energy, as fluctuations in wind speed can occur quite fast. The problems caused increase with larger amounts of wind capacity being installed. A critical case are very high wind speeds, as in a storm, when all capacities are producing at nominal capacity. If the wind speed increases further, the plants will turn out of the wind to prevent structural damages and produce no power any more within a very short time period. The resulting deficit has to be covered by conventional and other renewable capacities, which can be scheduled on demand[97].

[97] The gradient with which this deficit occurs can be limited by intelligent wind power management concepts, e.g. by gradually switching off wind turbines already before the maximum wind speed is reached.

The wind power feed-in data is provided as a set of hourly mean values for a whole year as well. The time series are derived from the wind model described in [Sensfuß et al. 2003][98]. This model calculates the output of the current and the predicted future composition of wind parks in Germany and Spain, based on historical hourly wind speed time series data obtained for characteristic sites (22 in Germany and 10 in Spain) in different regions on-shore (mountain, hill, near coast, coast) and off-shore[99]. For Spain, the measured wind data is available for one wind year (1999, with a good wind energy yield). For Germany, wind data for a good (1990), an average (1995), and a bad wind year (1996) is available. In both countries the composition of wind parks is elaborated in scenarios for the years 2000 to 2020 in 5-year intervals[100]. The Simulink model allows to choose wind power input from any of the above mentioned data sets. In Figure 19 the time series for the year 2000 in Germany (good wind year) is shown.

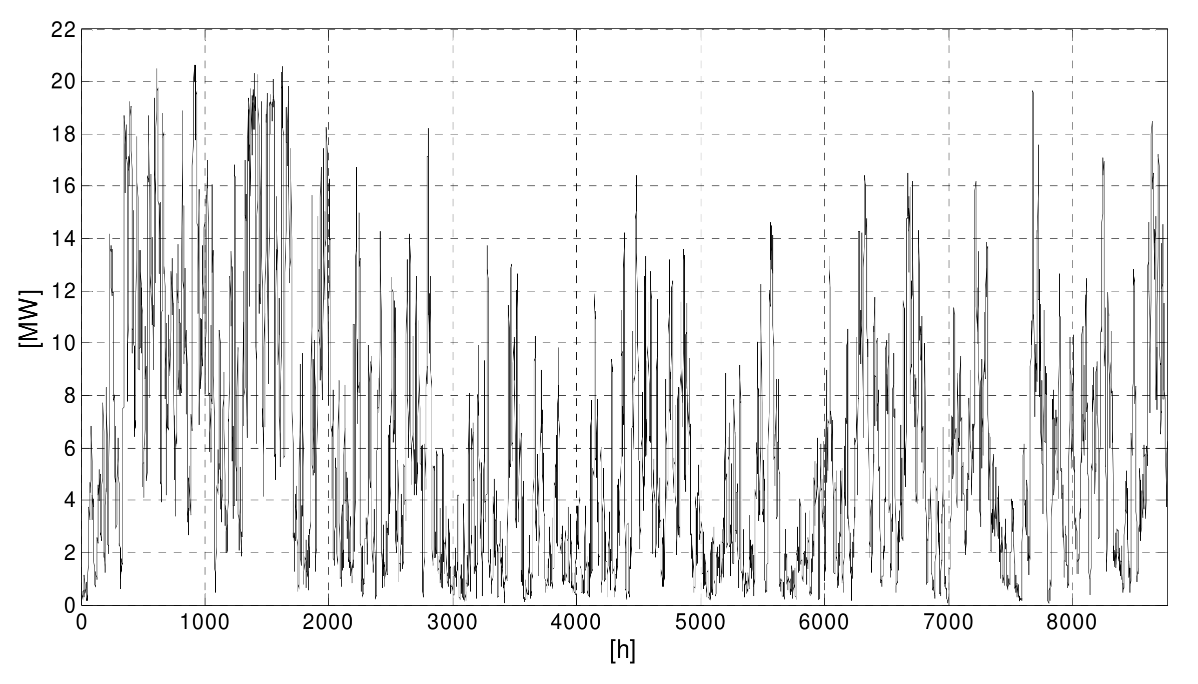

Figure 19: AEOLIUS input: Hourly wind power production time series for Germany, 2010 (based on data from [Sensfuß et al. 2003])

Hydropower data is also fed into the model. As it is much less subject to short-term fluctuations, it is easier to integrate into power production planning beforehand. Interpolated monthly mean values are thus provided as input to the model [Quaschning 2000], which can be considered as sufficiently accurate. Both a linear and a spline interpolation of the values can be chosen (see Figure 20).

98 An overview and classification of other possible simulation methodologies for the generation of wind power feed-in time series can be found in [Sontow 2000, p. 29 ff.].

99 Data correlation is relevant for the time series measured at individual sites. As wind speed measurements from characteristic sites all over Germany and Spain have been considered, the correlations between these sites are implicitly reflected in the total wind power output curve.

100 For a more detailed description of the wind model used to derive the wind power time series data please refer to [Sensfuß et al. 2003].

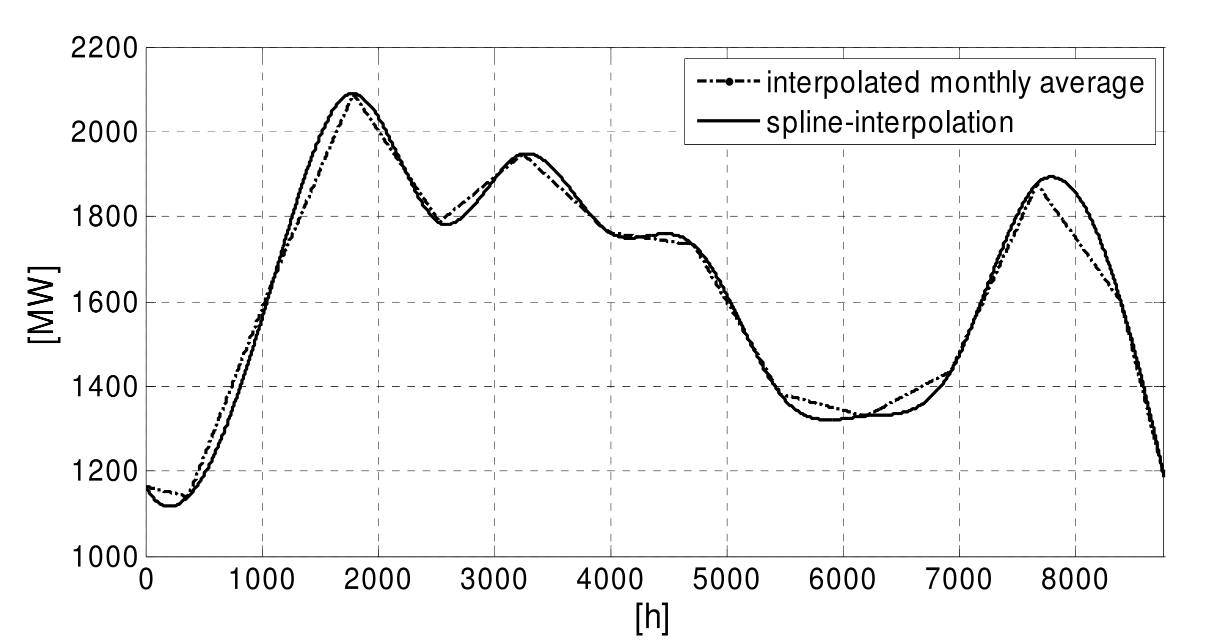

Figure 20: Annual variation of hydropower production in Germany (based on [Quaschning 2000])

The feed-in of other renewable electricity production, as e.g. from solar power, biomass, or geothermal sources can also be included in the model. While the contribution of fluctuations from solar power is negligible compared to those resulting from wind, the other technologies can be scheduled similar to conventional plants. However, as the incentives for renewable electricity generation in place are not differentiated for different load categories, producers will more or less feed in electricity whenever possible. Thus, a constant level is chosen as the most adequate representation of feed-in from these sources.

6.3 Forecast module

The function of the forecast module is to calculate forecast time series of both electricity demand and wind power feed-in data for three different forecast time horizons (24 hours, 4 hours, and 1 hour). The residual load as the difference of these two time series for each forecast time horizon is used to schedule the production of the conventional plant portfolio.

In order to simulate realistic conditions for power plant scheduling, the uncertainty connected to the prediction of the exact values of the cumulative wind power output needs to be taken into account. The forecast quality of wind power prediction tools can be characterised by RSME[101] values (see e.g. [Waldl et al. 2000], [Bettels et al. 2002], [Rohrig 2003]) for different wind power prediction time horizons. In order to introduce these time-dependent uncertainties into the model, the cumulated

[101] Root mean squared error. It is derived from the difference between the $\tilde{x}_t - \hat{x}_t$ between the predicted value and the actually observed value as follows: $RMSE = \frac{1}{T} \cdot \sqrt{\sum_{t=1}^{T} (\tilde{x}_t - \hat{x}_t)^2}$

deterministic values resulting from the actual measurements are multiplied by a randomly varying factor. The RSME values for the different forecast time horizons are interpreted as Gaussian noise levels[102] for this factor, which has a mean value of 1.

In Table 8 the forecasting uncertainties for different time horizons are listed.

Table 8: Forecasting uncertainties [Waldl et al. 2000]

Forecast horizon [h]	6	12	18	24	36	48
RMSE [%]	33.4	33.4	38.2	40.0	36.5	41.8

The noise levels are thus more pronounced for the longer forecast horizons and decrease for the shorter forecast horizons, as the predictability for both the fluctuations in renewable energy production and demand increases for shorter time periods. The same proceeding, but with lower noise levels, i.e. corresponding to a greater precision, has been applied for electricity demand forecasts. Prediction errors for demand forecasts can e.g. be found in [Fischedick 1996].

Moreover, insecurities of the actual demand versus the projected demand, e.g. due to temperature variations, are taken into account by increasing the demand profile with a safety factor, which is set to 3.5% of the forecasted average load for each day. While the longest forecast horizon is used to schedule the base load capacities, the medium term forecast is used to schedule intermediate load capacities. The one hour forecast is used to schedule peak load capacities and control power reserves of the other plant types currently in operation. Remaining load imbalances can be compensated by storage facilities (pumped storage plants), which are also modelled.

However, due to the interpolation between hourly mean values and the superimposed noise, even the one-hour forecast is subject to inaccuracies in predicting the actual feed-in of renewable electricity production and demand. In order to assure a complete satisfaction of demand, these inaccuracies need to be compensated by peaking capacities and control power reserves of the other power plant types currently in operation. Very fast load changes can in addition be compensated by pumped storage plants, which are also modelled. The modelling of the different plant types with their respective parameters (capacities, load-following characteristics, costs, emissions, etc.) is described in the following paragraph.

[102] Using a Gaussian distribution for all wind power feed-in levels is an approximation. For very low or very high wind power feed-in, asymmetric probability functions could be introduced into the model as e.g. calculated from the ISET measurement series in the Dena study [Dena 2005]. This would eliminate the possibility for positive noise at very high feed-in levels or negative noise at very low feed-in levels. An alternative method to simulate forecast uncertainties is the use of the ARMA (Auto Regressive Moving Average) series method described by [Söder 2004].

6.4 Heuristic approach for power plant scheduling

For the use in the model the conventional power plant portfolio is represented in an aggregated way and consists of three different categories of plants: base load, intermediate load, and peak load plants. In the functional model of the German power sector these can be characterised as shown in Table 9. Using the same classification of plant types, but with different parameterisations, also other countries and / or future expansion stages of the power plant portfolio and the according parameters can be represented.

Table 9: Modelled power system parameters for Germany (adapted from [Krämer 2003])

	P_{net} [MW]	Number of plants [-]	$\eta_{nominal, best}$ [%]	Availability [-]	Var. costs (excl. fuel) [€/MWh_{el}]
Thermal power plants	104850	221	-	-	-
Nuclear I	1250	14	33	0.98	0.81
Nuclear II	750	8	33	0.97	0.81
Lignite I	1000	12	39	0.95	3.36
Lignite II	500	14	39	0.95	3.36
Hardcoal I	750	33	40	0.98	2.00
Hardcoal II	500	21	40	0.96	2.00
Fuel-oil I	500	11	39	0.98	1.35
Fuel-oil II	200	12	39	0.96	1.35
Gas I	500	9	42	0.99	0.68
Gas II	200	87	42	0.98	0.68
Hydraulic power plants	7521	2			
Run-of river	2070	1	100	100	0
Pumped-storage	5451	1	75	100	0
Total	**112371**	**223**			

The so-called ‘must-run’ capacities like nuclear and lignite power plants have been modelled in the base load category. These plants are characterised by low specific production costs. They are technologically restricted to slow changes of their output, which in addition can only be realised in a narrow window in order to keep plant operation economical and prevent excessive material wear.

In the intermediate load category, all plants are included, whose load following characteristics are somewhat faster and which can consequently be used for load-following purposes up to a certain degree. While load variations can also take place in a greater range, these plants usually have higher specific production costs than base load plants. The hard-coal capacities are regarded here.

In the peak load category the following plant types are included: oil- and gas-fired plants (gas turbines and combined cycle plants) which are able to realise load changes very quickly and to start up in a matter of minutes rather than hours. Their flexibility is, however, associated with the highest specific production costs.

Similar to [Krämer 2003], ten different power plant types are modelled in five fuel-categories, each with two different block sizes (see Table 9). The power plants modelled are geared to meet the technical parameters and the number of typical plants, thus creating a representative set of power stations. The pre-scheduling is based on heuristic procedures, for base, intermediate, and peak load power stations. The still remaining load differences between scheduled load and actual load are balanced by stand-by capacities and pumped-storage reserves. A compensation of the arising fluctuations can thus be compensated by a sufficient supply of conventional stand-by capacities.

The following technical and economic features are used for parameterisation:

- P_{max}, P_{min} : maximum output and minimum output [MW_{el}];
- η : conversion efficiency [%];
- c_{var} : variable costs (e.g. fuel costs) [cent/kWh];
- v_{change} : maximum load change gradient [%/min];
- CO_2_*output* : specific CO_2-emissions [kg/MWh_{el}];
- *num* : number of plants [-];
- *availability* : plant availability [%];
- *switch_on* : threshold for plant switch-on [MW];
- *switch_off* : threshold for plant switch-off [MW].

A simple Simulink flow-sheet representation of a power plant is given in Figure 21. Depending on the demanded load, which is calculated based on an hour-ahead forecast in this case, it is decided whether the threshold for a plant startup or shutdown is exceeded. The activity level of the plant is matched to the demand and can be adjusted between the minimum and the maximum possible output of the plant. The gradient with which the load is adjusted is restricted by the load following ability of the specific power plant type. The electrical output of the power plant, any remaining, uncovered demand, as well as the variable costs and emissions caused by the power production process are derived for further processing in the model. Any number of different types of such power plant model units can be combined to represent a given plant portfolio.

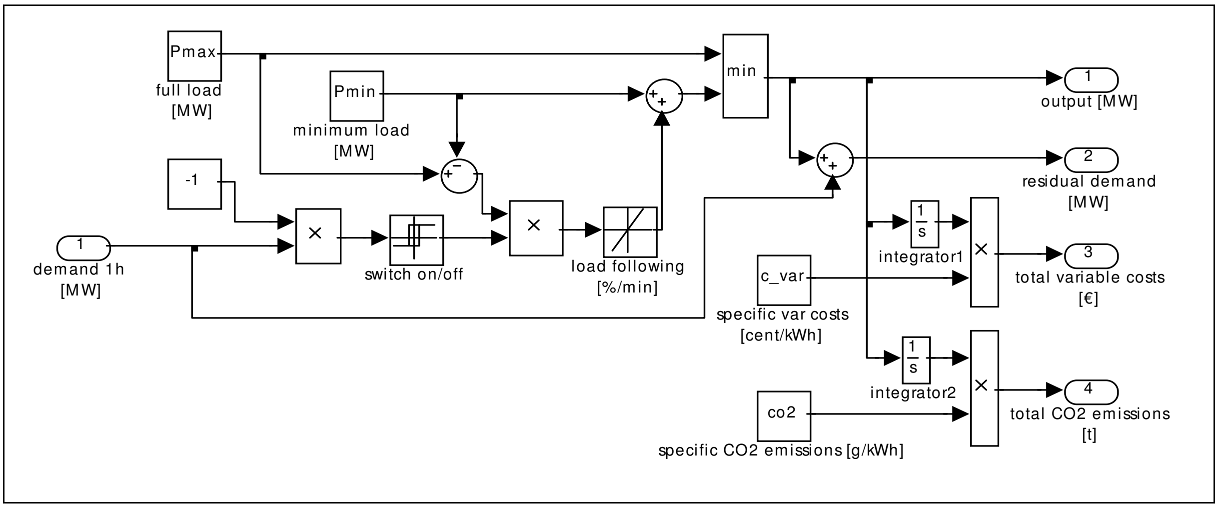

Figure 21: Flow-sheet representation of a power plant in AEOLIUS

In order to provide a sufficient security of supply, inherently inaccurate load and wind power feed-in forecasts, as well as possible power plant failures must be handled by the power system. It must thus contain enough reserve capacities for the above cases[103].

While the forecast errors from the expanding fluctuating electricity production from wind power are regarded to have a negligible effect on the required primary control range (cf. [Dany 2000], [Dena 2005]), an influence of the forecast error on the load deviations in the time frame of secondary control exists. However, in the Dena study [Dena 2005, p. 252]) it is assumed that the influence in the time frame of secondary control does not necessitate additional secondary reserves. The influence of the forecast error on the load deviations is most significant in the time frame of tertiary control. Thus, the fluctuations on the power production side are mainly balanced by tertiary reserves, which are also used for the compensation of imbalances resulting from the fluctuation of electricity demand. Consequently, the following requirements determine the necessary amount of tertiary reserve in the model:

- coverage of plant failures;
- coverage of demand forecast errors;
- compensation of output variations from fluctuating renewable electricity sources.

In accordance with [Fischedick 1996], the minimum requirement for spinning tertiary reserve in the model is set to 2.5% of the synchronised net plant capacity.

For the modelling of the standing tertiary reserve, the amounts necessary for the coverage of plant failures and demand forecast errors were taken into account, while the spinning reserve is required to compensate the fluctuations from renewable

[103] Not in all cases does the necessary reserve have to be covered in the grid area where it is demanded, part of the balancing energy can usually also be purchased from neighbouring TSO areas. In the model, however, control power must be provided by the activation of reserves within the considered region and cannot be obtained from elsewhere.

electricity generation. The risk of plant failures is compensated by providing tertiary reserve equal to the amount of power provided by the biggest currently operating block in the system. This is regarded as an acceptable simplification instead of a probabilistic modelling of plant failures [Fischedick 1996]. As suggested by the same author, errors of demand forecasts are taken into account by multiplying the simulated demand profile with a safety factor. Within the AEOLIUS model this factor is set 3.5% higher than the forecasted average load for each day.

When high amounts of fluctuating wind power production are introduced into the electricity mix, the question of how much tertiary reserve should eventually be provided for the compensation of fluctuations arises. Individual wind turbines show maximum fluctuations of 75% within one minute and up to 90% within five minutes in terms of their nominal capacity. The most secure option, which would be to cover all capacity above the secured capacity of wind power plants by tertiary reserves, cannot be a reasonable solution for a high penetration of wind power. Thus, for the simulations the frequency distribution of hourly fluctuations is used to dimension the amount of tertiary reserve. As described in [Sontow 2000], the maximum amplitude of fluctuations likely to happen with a 97% probability is determined from the empirical probability function and is used as a target value for spinning reserve in the model calculations. The required amount of reserve is then distributed among all blocks of intermediate load plants, which contribute to the reserve with a fixed percentage of 15% up to a maximum of 20% of their nominal capacity.

In order to allow for a clear and comparable quantification of fluctuation-induced effects on the scheduling of conventional capacities in a specific region, the modelling of other variables of the power market (e.g. power purchased from or sold to energy exchanges like the EEX) was deliberately not included in the model.

6.5 Costs and emissions

With the time horizon of AEOLIUS being one year and due to the rather long lead times for the construction of new power plants it is regarded legitimate to assume that the structure of the power generation system remains unchanged during this period[104]. Thus, the amount of fixed costs to be accounted for, which results from investments, interests, insurances, and fixed operating costs as e.g. staff wages and revisions, is a constant figure for the time horizon of the model and does not have any influence on the scheduling of power plants. That makes it sufficient to take only the variable costs of power generation into account, which result from fuel costs on the one hand and other variable operating costs, as e.g. from flue gas cleaning.

Fuel costs depend on world market prices and the specific heat-demand of the plant, which slightly varies with power output. Generally, an average specific heat demand

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[104] The long-term changes of the electricity sector are analysed with the PERSEUS-RES-E linear optmisation model described in chapter 7. The current and future sector structure as a result of that model can be used as the input sector structure for an analysis with AEOLIUS.

is sufficient to model the conversion of fuels to electricity in the power plants. However, with a growing wind power feed-in and the connected increase in necessary reserves it can be expected that plants will operate at partial load more often. To account for partial load situations, the load-dependent efficiency profiles shown in Figure 22 were used in a stepwise linearised form[105]. Starting with the specific heat demand, the annually required quantity of thermal energy [MWh/a] to be delivered by the fuel is calculated. The annual fuel costs are calculated by multiplying this value with the specific fuel costs [cent/kWh]. For the fuel-prices and other variable costs fuel- and / or technology-specific values from the power plant database at DFIU[106] are used. CO_2-emissions are calculated by multiplying the amount of thermal energy required by the fuel-specific CO_2-emission coefficient given in [kg CO_2/MWh].

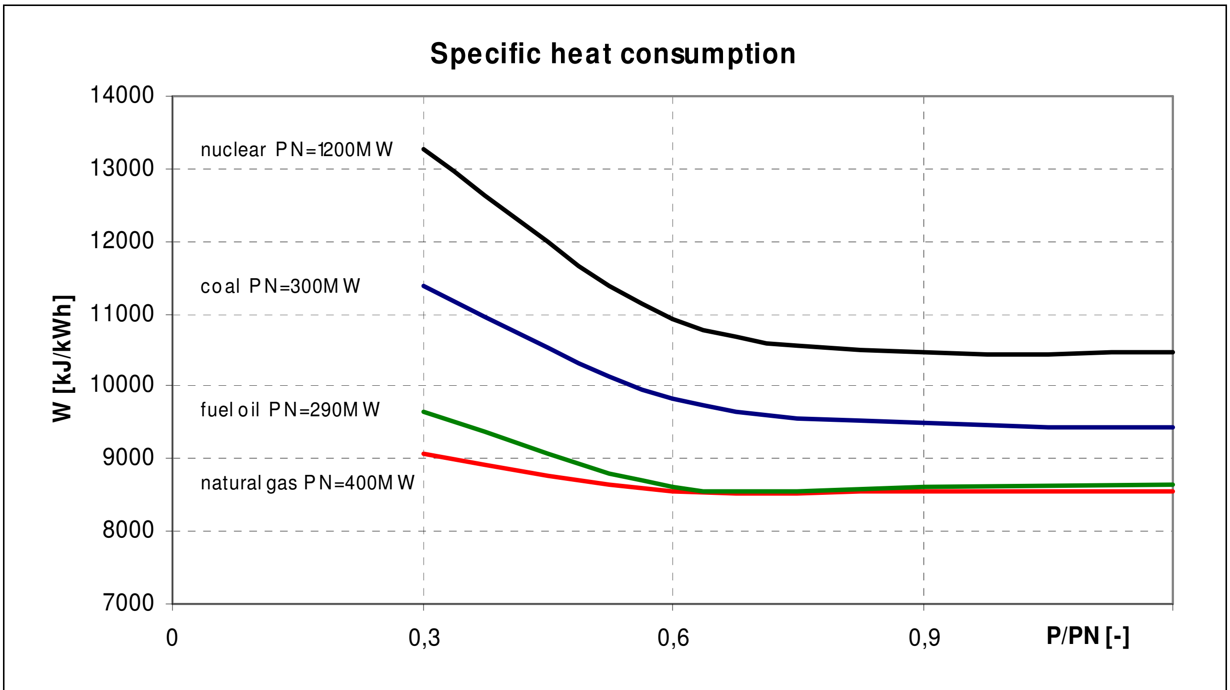

Figure 22: Performance-related specific heat consumption of power plants (based on [Taud 1979])

By substituting fossil fuels in the power generation system the use of wind energy leads to a decrease of CO_2-emissions in the power sector. However, not the complete amount of costs and emissions associated with a fossil-generated unit of electricity can be avoided. These inherent losses are due to the fact that the increased requirements for spinning reserves as well as more frequent load changes and plant start-ups cause a higher specific energy use of the thermal plants. This means that conventional capacities are forced to operate below their maximum efficiency for longer periods of time than without wind power feed-in. Such operation

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[105] In linear optimisation models as the PERSEUS model described in the next chapter, load-dependent efficiencies can in principle also be accounted for in linearised, mixed-integer form (cf. e.g. [Fichtner 1999].

[106] **D**eutsch-**F**ranzösisches **I**nstitut für **U**mweltforschung (French-German Institute for Environmental Research).

causes additional fuel consumption and thermal wear in the plants, which limits the possible cost and emission savings (see Figure 25 and Figure 26). In addition to the reduced efficiency at partial load the model also accounts for the emissions and fuel consumption related to plant start-ups, which in accordance with [Fischedick 1996] varies between 2 GJ/MW and 6 GJ/MW, depending on the preceding downtime of the specific plant.

6.6 Simulation applications

The following two paragraphs give an overview of how the AEOLIUS simulation model can be used to quantify the effects and the actual, net benefits of wind power feed-in in terms of costs and emissions.

Firstly, the **substituting effects** of an introduction of growing amounts of wind power into an existing power system structure are analysed. For the case of Germany, the avoided conventional generation is calculated, as well as the related emissions and cost savings per kWh of wind energy. Wind energy use primarily leads to a substitution of existing production, but due to the low secured capacity it contributes only marginally to the substitution of capacities. This exemplary case can therefore be regarded as representative for a medium-term time horizon, i.e. equal to or less than 10 years, where the existing capacity structure characterised by overcapacities does not show a notable change. In later time periods, when structural changes are induced in the power sector, e.g. due to large numbers of plants reaching the end of their lifetime, or an adaptation to emission constraints, the existing power system structure can not be taken as a reference for comparison any more.

Secondly, the **effects of wind power fluctuations on power system efficiency** can be identified. This is possible not only for the existing power system, but also for its future expansion stages. Due to the fluctuations, power plants have to be operated in a different, reactive manner, which causes a more inefficiencient use of fuel than a constant or even perfectly controllable output of wind power production would allow. By comparing costs and emissions of a simulation with a constant wind power feed-in to those of a simulation with the fluctuating feed-in actually observed, the inefficiencies can be quantified. These calculations provide additional information for a refined representation of wind power production in the long-term PERSEUS-RES-E model (see chapter 7), where fluctuations cannot directly be modelled due to the temporal resolution of the model being limited by the model size.

6.6.1 Substitution of existing generation by wind power integration

This paragraph gives an overview of how the AEOLIUS simulation model can be used to quantify the effects and the net benefits of wind power feed-in in terms of costs and emissions. In the presented example, the conventional power plant portfolio installed in Germany in the year 2000 and the electricity demand are taken as a reference. Wind power is introduced into the model in three different stages based on the expansion of wind power use in Germany as anticipated by [Sensfuß et al. 2003].

While 6 GW were installed in the year 2000, 17.3 GW and 22.4 GW are introduced as the expected values for 2005 and 2010, respectively. A wind power production of 12 TWh, 34.9 TWh, and 50.4 TWh is introduced for the shares expected in the different years, assuming a good wind year with otherwise unchanged framework conditions in order to have a comparable basis.

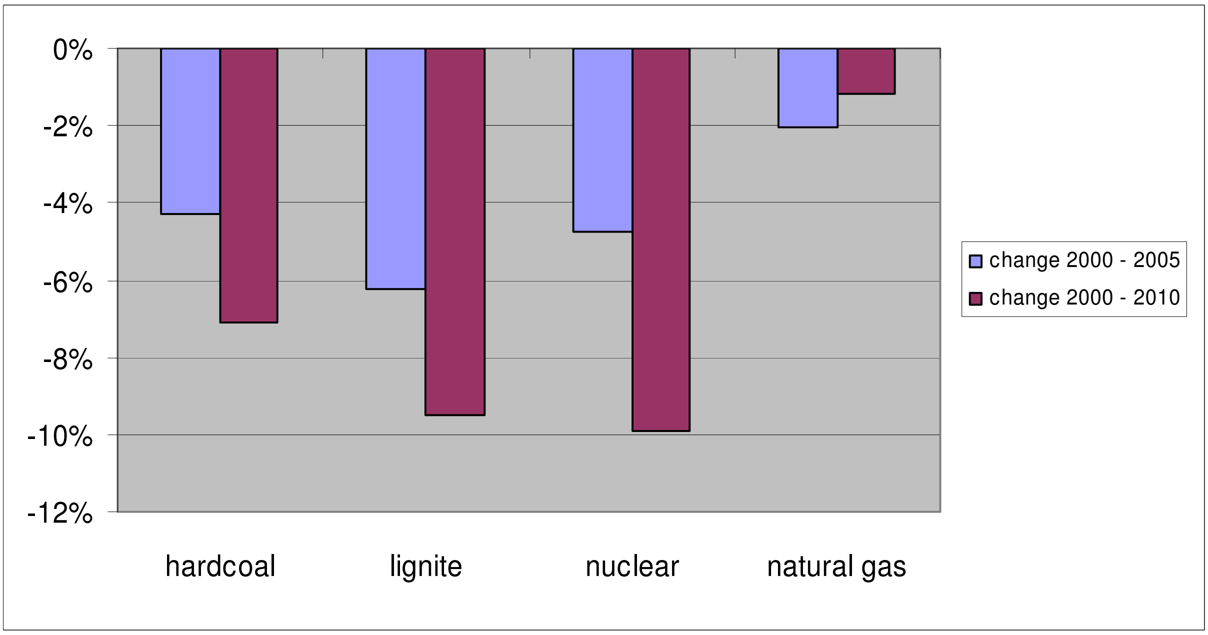

Figure 23: Substitution of conventional power production by wind power

Actual power production data from the year 2000 and the corresponding simulated power production shares are in good accordance. Figure 23 shows how the reductions in conventional power production caused by an increasing wind power use are distributed among the different fossil technologies. Depending on the wind penetration results show a substitution mainly of coal-fired (about 4% in 2005 and 7% in 2010), lignite-fired (5% in 2005 up to 9.5% in 2010), as well as of nuclear production (4.5% in 2005 and nearly 10% in 2010). With increasing wind shares the effect becomes more distinct and does not only affect the production characteristics of intermediate load generation, but even more clearly those of base load generation.

This effect can also be directly observed in the varying characteristics of base load generation in the three-week period depicted in Figure 24. As quickly reacting natural gas fired power plants are needed to compensate for the short-term fluctuations of wind power, the amount of natural gas fired electricity displaced is negligible and, in contrast to the results above, decreases for higher shares of wind energy (from 2% in 2005 to slightly more than 1% in 2010).

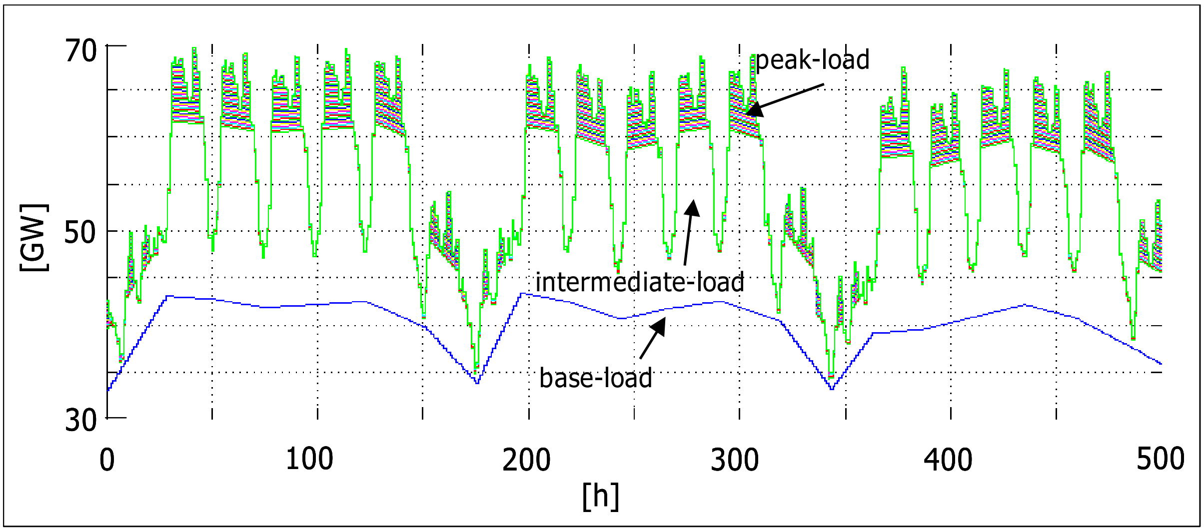

Figure 24: Load coverage by base, intermediate, and peak load capacities

The overall costs and CO_2-emissions of the three wind power expansion stages were compared to the costs and emissions of a reference case with the same conventional power plant structure, but without any wind power feed-in. This comparison with a purely conventional electricity system allows to calculate the average values of costs and emissions avoided per one kilowatt-hour of wind energy feed-in. This is done by relating the differences between the total costs and emissions of the reference case and those of each expansion stage to the wind power feed-in of the respective expansion stage. A complete substitution of one unit of conventionally generated electricity and the related generation cost by one unit of wind energy is only theoretically possible. In Figure 25 the full costs of one kilowatt-hour of coal fired electricity are taken as a reference. Instead, only the net cost savings accounting for the fluctuation-induced efficiency losses can be subtracted from the average feed-in tariff. These net savings decrease with growing shares of wind power production. As a result, the specific costs of wind power use are higher than in the ideal theoretical case. The calculated net costs of wind energy feed-in are visualised in Figure 25.

Within the German feed-in tariff regulation, an average compensation of about 7.45 cents/kWh is paid for wind energy feed-in over 20 years. When hypothetically assuming that a conventionally generated unit of electricity can be fully replaced without efficiency losses by one unit of wind energy, this would mean that in the best case full costs of about 4.3 cents/kWh could be saved by replacing electricity generated from hard coal, with remaining net costs for wind power feed-in of 3.15 cents/kWh. However, the net cost savings resulting from AEOLIUS are much lower, for the expected wind energy feed-in in 2010, for example, only

1.14 cents/kWh of operating costs can be saved[107] in the conventional power plants. This corresponds to net specific costs of 6.31 cents/kWh[108] of wind energy production for the 2010 feed-in amount. Accordingly, the fluctuation-induced cost difference, which can be derived from the comparison with the ideal loss-free replacement of conventional electricity, amounts to 6.31 – 3.15 = 3.16 cents/kWh.

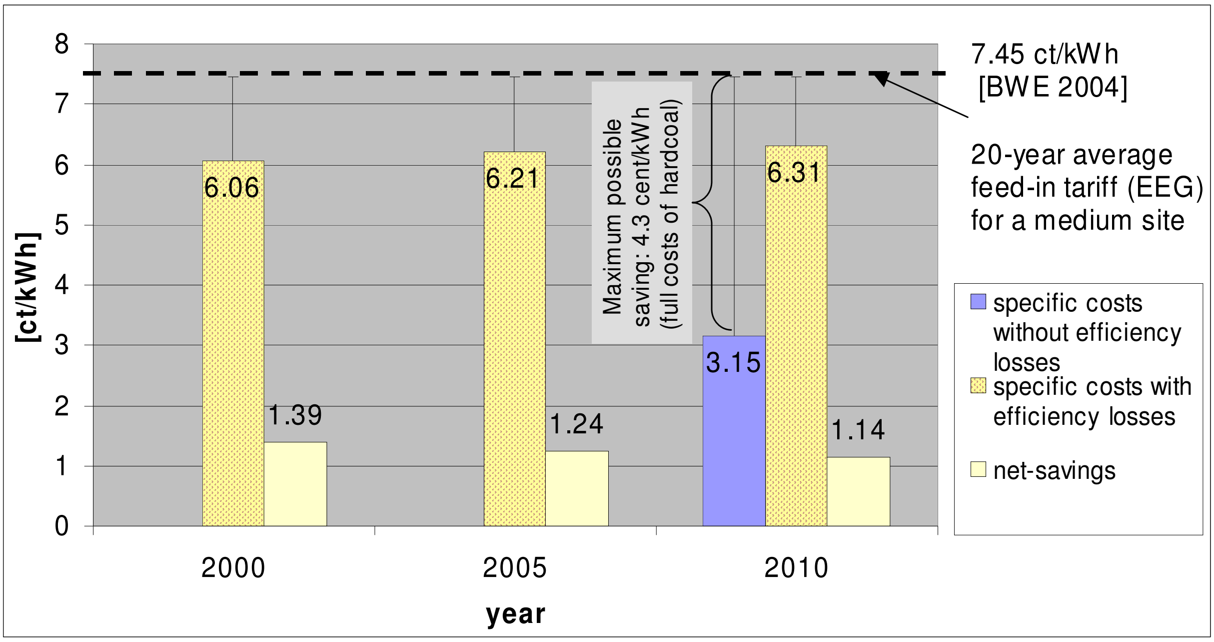

Figure 25: Theoretical and actual specific costs of wind power feed-in

This difference is due to the fact that the increasing reserve and control power requirements have to be fulfilled primarily by fossil-fuelled plants, causing losses in fuel efficiency and increased thermal wear. In addition to the reduced efficiency at partial load, the model also accounts for the emissions and fuel consumption related to plant start-ups, depending on the preceding downtime of the specific plant. Figure 26 also shows that these net savings decrease with growing shares of wind power production, with slightly rising specific additional costs as a result. It has to be kept in mind that costs for most probably unavoidable grid expansions are not accounted for in these calculations. Along with fuel efficiency, the ecologic benefits, i.e. the possible emission reductions, decrease with the growing share of wind energy in this case

[107] On the liberalised Nordic electricity market, [Holttinen 2004] and [Nielsen et al. 1999] have calculated higher values of about 2 cents/kWh for wind power, depending on prediction accuracy and the amount of hydro power available. The Dena grid study [Dena 2005] finds cost savings of 1.76 cents/kWh for 2007 with an increase of up to 2.57 cents/kWh for 2015 in the reference scenario. When compared to the static analysis performed with AEOLIUS, the higher savings and their increase result from the assumed rise in fuel prices over the time horizon and the assumed price of CO_2-certificates.

[108] For 2007 the Dena study [Dena 2005] states a very similar value of 6.34 cents/kWh for the net costs. Due to the increase in cost savings from wind power production and the decrease of the total amount of feed-in tariffs taken into account, this value decreases for 2010 (5.99 cents/kWh) and 2015 (4.35 cents/kWh).

with a static conventional power plant portfolio[109]. Here, the effect is even more pronounced than the influence on the costs. The reason is that wind energy does not only substitute fossil fuels, but also electricity production from nuclear power plants. As the latter is practically CO_2-free, no significant amounts of emissions are saved by its replacement[110]. This effect in addition to the reduced fuel efficiency caused by the increasing reserve and control power requirements causes a marked decrease in specific emission savings, as depicted in Figure 26.

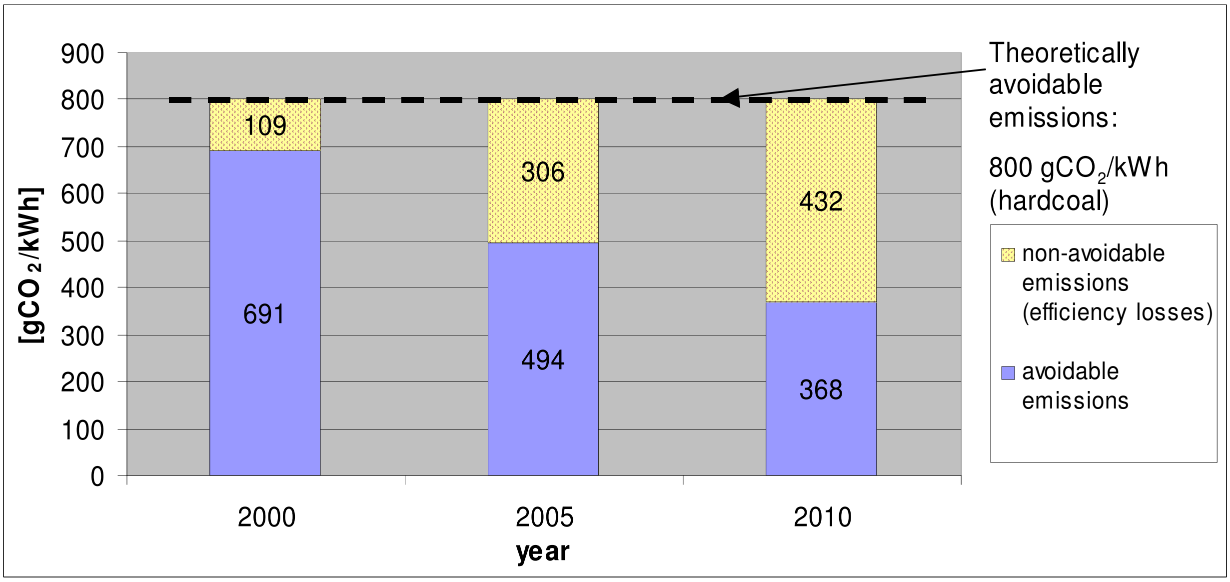

Figure 26: Specific emission savings with increasing exploitation of wind energy

Thus, depending on the share of wind power in the system, only 32% (2000) down to 27% (2010) of cost savings, and between 86% (2000) and 46% (2010) of the theoretically possible emission savings can be realised. The results also depend very much on the structure of the conventional power generation capacities, whose production is partly replaced.

6.6.2 Calculation of efficiency losses induced by wind power fluctuations

Due to the limited temporal resolution of the PERSEUS-RES-E modelling approach with 36 characteristic time slots per year - 2 characteristic days for each season, with weekdays represented by 6 time slots and weekend days by 3 time slots, see chapter 8.2 - there is no possibility for an adequate representation of wind power fluctuations. A larger number of time slots, which would increase the model size and computation

---

[109] Similar effects of lower specific emission savings have been described by Holttinen [Holttinen 2004], and also Liik [Liik et al. 2004], who modelled wind power in a unit commitment model of the Estonian electricity system, which is dominated by conventional thermal generation.

[110] The results concerning avoided emissions can be regarded as a pessimistic estimation, as it is assumed that the two main base load technologies nuclear power and lignite power plants both need to contribute equally to the regulation of wind fluctuations. Considering the extremely base load oriented production characteristics of nuclear power plants and their low flexibility for load changes, it could alternatively also be assumed that no nuclear power can be displaced. In this case, more emission intensive lignite fired baseload power would be substituted and the decrease of avoided emissions would be less steep.

times substantially, cannot provide for an adequate representation of fluctuations, either. Even though on average wind power production and load are positively correlated, i.e. usually more wind power is produced during the daytime, when also most of the electricity is used, the fluctuations vary from day to day. Thus, if fluctuations were introduced in a generalised form for a typical day, this would introduce a systematic bias into the model and favour or discriminate certain technologies used in the time slots where the fluctuations are modelled.

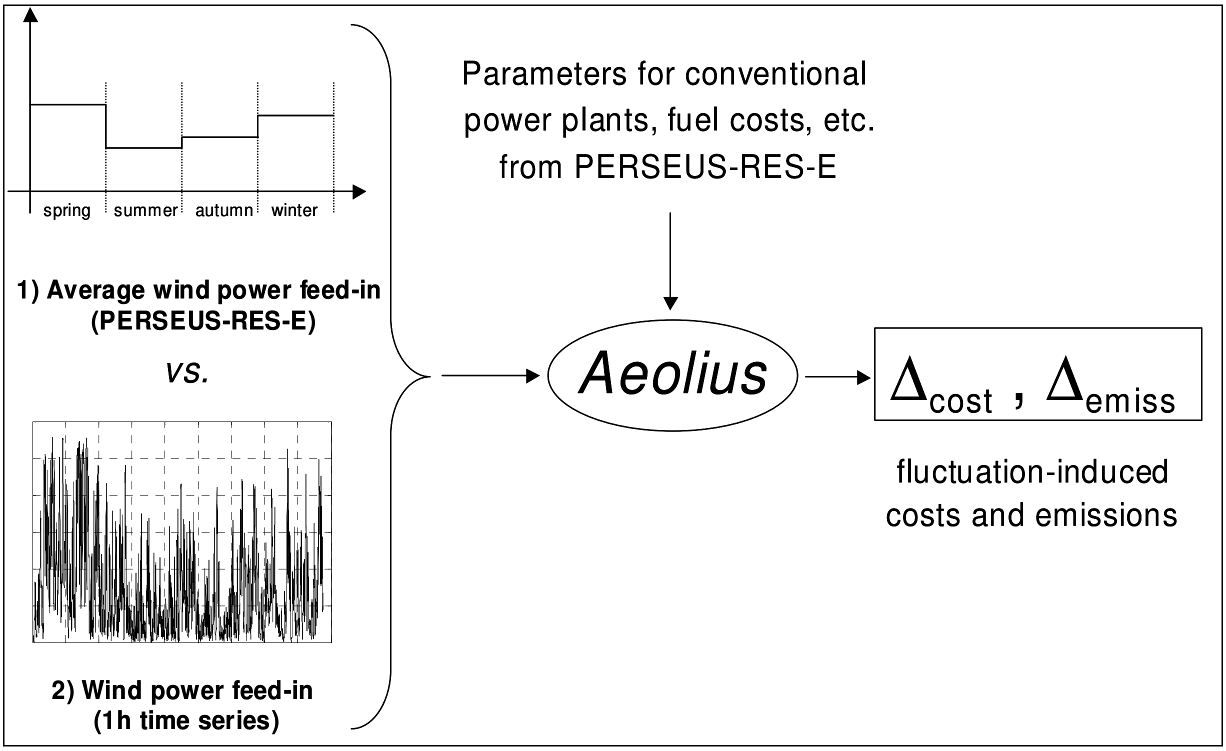

Figure 27: Use of AEOLIUS to determine fluctuation-induced costs and emissions of wind power production

Thus, only the annual average or seasonally differentiated average wind power production can be introduced into the aggregated typical day structure of the model instead. However, using AEOLIUS the difference in costs and emissions caused by the fluctuating nature of wind energy feed-in, which can not be directly modelled in this compromise solution for long-term modelling, can be determined. In order to do so, two AEOLIUS model runs are carried out for each time period modelled in PERSEUS-RES-E: one with the average production profile used in PERSEUS-RES-E, where wind power in effect is represented as a base load technology, and another one with the actual fluctuating feed-in characteristics. The structure of the electricity system and the fuel costs in AEOLIUS are chosen equivalent to the structure determined by PERSEUS-RES-E. This procedure is also illustrated in Figure 27. The difference in total system cost observed for each period can then be related to the amount of wind power produced in each respective period. In the following, these specific cost and emission differences will be referred to as the *specific fluctuation-induced costs* and *specific fluctuation-induced emissions* of wind power production.

The calculation method just described is applied to the two countries with the largest wind energy growth in the EU so far, i.e. Spain and Germany, for which representative and temporally sufficiently resolved wind power production data is available. For the electricity sectors of both countries, the fluctuation-induced emissions and costs are determined for the scenario with the highest penetration of wind energy, and thus also the most pronounced influence of fluctuations. For this scenario, which is called TARGETS_EU, the results of this combined application of PERSEUS-RES-E and AEOLIUS in, will be described in detail in chapter 9.3.5.

7 Development of an optimising energy system model to assess the integration of renewable electricity

7.1 Evolution of optimising energy system models as the precursors of the developed PERSEUS-RES-E model

Since the oil crises in the 1970s, which triggered their development and application, energy system models based on Operations Research methods have become frequently used tools for policy advisors and for the corporate planning activities of electric utilities. Originally, their application was motivated by the wish of industrialised nations to curb their dependence on imported mineral oil and to elaborate strategies aimed at rearranging their national energy systems accordingly. In the course of time the models were refined and extended by including further modules to address the environmental effects of energy conversion processes (especially acidification and eutrophication due to SO_x and NO_x emissions). Since the early 1990s, energy system models have also been used for the elaboration of GHG emission reduction strategies in the context of the global warming discussion.

Models of this type are characterised by a strongly technology-oriented representation of the real energy supply system, and are thus sometimes also referred to as “engineering” models. The commonly employed energy and material flow models usually represent the real energy supply system by means of a directed graph, where the edges of the graph represent the energy and material flows and the nodes represent conversion units or grid nodes. Taking into account all relevant techno-economic characteristics, the resulting detailed representation of the energy conversion process chain allows an immediate comprehension of the technical implications induced by changing exogenous factors, as e.g. policy measures or fuel price variations. A limitation of this process-analytical, so-called bottom-up approach is that existing feedback loops with other markets, e.g. for raw materials or industrial goods, as well as intersectoral linkages in general are not accounted for[111].

A variety of optimising energy system models exists today. Most of them are based on a few internationally known and widespread approaches like EFOM (Energy Flow Optimisation Model, see [Finon 1974], [van der Voort et al. 1984], MESSAGE (Model for Energy Supply System Alternatives and their General Environmental Impact, see [Agnew et al. 1979], [Messner 1984], and [Messner et al. 1999]), and MARKAL (Market Allocation Model, see [Fishbone et al. 1981]). The basic model versions, which were developed in the framework of European research projects, have been adapted and enhanced by various research institutions in national or international research efforts[112]. In Germany these developments resulted in tools like IKARUS

[111] Such models are also referred to as sectoral, or partial models (see e.g. [Enzensberger 2003]).

[112] The spectrum of model developments within the MARKAL group of models is described in [Seebregts et al. 2002], and that of the PERSEUS group of models, which are based on the EFOM model, is given in [Wietschel et al. 1997b].

(see [Martinsen et al. 1997]), EIREM/EUDIS (cf. [Hoster 1996], [Kreuzberg 1998]), EMS [Gerdey et al. 2002], E^3-Net [Fahl et al. 2002], as well as the PERSEUS family of models[113].

Based on the EFOM-ENV model, the energy and material flow model family PERSEUS[114] was developed at the Institute for Industrial Production (IIP) of the University of Karlsruhe. The models of the PERSEUS family are designed to enable a quantitative assessment of questions related to energy systems on (multi-)national, regional, and utility level. The PERSEUS methodology is based on a representation of energy conversion technologies and the interconnecting flows of energy forms (like electricity and heat) and materials (i.e. primary energy carriers, pollutant and GHG emissions). The complete energy sector supply chain of a country - starting from the resources via several energy-conversion technologies up to the supply of final energy - is modelled in a consistent, vertically integrated approach.

In the PERSEUS models, existing and future energy technologies are represented resulting in a linear programming approach implemented in GAMS (General Algebraic Modelling System, see section 2.2.4) [Brooke et al. 1998], thus making it possible to consider the interdependencies between individual investment options.

The models are based on linear and mixed-integer programming approaches. Their target functions consist of a minimisation of all decision-relevant expenditures within the entire system. Technical, economic, and ecological restrictions are integrated into the models in a suitable way to consider relevant system characteristics of the real energy supply system. Emissions resulting from electricity and heat generation as well as from the distribution of energy carriers (e.g. natural gas) are calculated. Restrictions can be imposed on individual or cumulated emission levels. Hence, the models can not only be used as a decision support tool for strategic planning under environmental constraints, but also as an environmental information system which generates data on current and future emission levels of all relevant pollutants and greenhouse gases. A data management system has been designed in order to provide a user-friendly interface. A detailed description of the modelling approach can be found in e.g. [Fichtner 1999] and [Enzensberger 2003].

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113 An overview of current energy models developed in different German research institutions can be found in the proceedings of a series of model experiments conducted ([MEX I 1999], [MEX II 2002], [MEX III 2004] and [MEX IV 2004]). In each of the different model experiments the focus is on the application of the models to a specific topic within the electricity sector and the results of the different approaches are compared. [MEX I 1999] analyses the structural and macroeconomic effects of climate protection from a national perspective. In [MEX II 2002] the effects of the German nuclear phase-out are evaluated, while [MEX III 2004] deals with the role of renewable electricity generation. In [MEX IV 2004] the focus is on the contribution of the German energy sector to European climate protection efforts.

114 **P**rogramme Package for **E**mission **R**eduction **S**trategies in **E**nergy **U**se and **S**upply.

Table 10: Modules of the PERSEUS family of models (based on [Frank 2003])

	Application	References
Methodological modules		
Optimisation algorithms		
Linear Programming	Different countries, utilities of Karlsruhe and Rottweil, RWE Energie AG, EdF	e.g. [Fichtner 1999]
Decomposition algorithm	Among others: Germany, Russia, Indonesia	e.g. [Ardone 1999], [Morgenstern 1991]
Iterative Optimisation	Germany	[Wietschel 1995]
Mixed-integer linear optimisation	Among others: utilities of Karlsruhe and Rottweil, RWE Energie AG, Karlsruhe Rhine Harbour Industrial Complex, Slovenia, Switzerland	[Lüth 1997], [Fichtner 1999], [Göbelt 2001], [Frank 2003], [Möst et al. 2004]
Stochastic linear programming	Energy utilities	[Göbelt et al. 2000b], [Göbelt 2001]
Target function		
Minimisation of expenditures	Different countries, regions, and utilities	e.g. [Fichtner 1999]
Profit maximisation	Utilities	[Göbelt et al. 2000a], [Göbelt 2001]
Goal programming	France	[Fleury 2005]
Application oriented Modules		
Focus of application		
Emission abatement strategies	Different countries, baseline calculation	[Ardone 1999]
CO_2 certificate market	EU-25	[Enzensberger 2003]
LCP/IRP strategies	Utilities of Karlsruhe and Rottweil	[Schöttle 1998]
Analysis of flexible instruments for climate change mitigation	Germany, Russia, Indonesia, India	[Ardone 1999]
External costs	Germany, Slovenia, France	e.g. [Lüth 1997], [Fleury 2005]
Capacity expansion and decommissioning planning	Utilities of Karlsruhe and Rottweil, RWE Energie AG, Wingas GmbH	[Fichtner 1999]
Contracting	Utilities of Karlsruhe and Rottweil	[Wietschel et al. 1999]
Evaluation of environmental policy instruments	Germany, Baden-Württemberg	[Dreher 2001]
Development of sustainability strategies	France	[Fleury 2005]
Design of (regional) energy networks	Karlsruhe Rheinhafen industrial complex, European natural gas market	[Frank 2003], [Perlwitz et al. 2005]
Renewable energies	Switzerland, EU-15	[Möst 2006], [Rentz et al. 2005b], [Rosen et al. 2006],
System boundaries		
International	Europe	[Enzensberger 2003]
National	Several countries	[Ardone 1999]
Regional	Northern Germany, Baden-Württemberg	[Dreher 2001]
Sectoral	Wood finishing	[Wietschel et al. 1997b]
Company level	Utilities of Karlsruhe and Rottweil, RWE Energie AG, Wingas GmbH	[Fichtner 1999]
Intercompany network	Karlsruhe Rhine Harbour industrial complex, cooperations in the energy sector	[Frank 2003], [Tietze-Stöckinger 2005]

Using the different models of this family, a number of studies, e.g. on regional, national, and international emission reduction strategies, international co-operation concepts under the UNFCCC, Least Cost Planning / Integrated Resource Planning as well as on utility strategies in the liberalised energy market, have been carried out (see Figure 28 and e.g. [Fichtner 1999], [Rentz et al. 1998], [Göbelt 2001]).

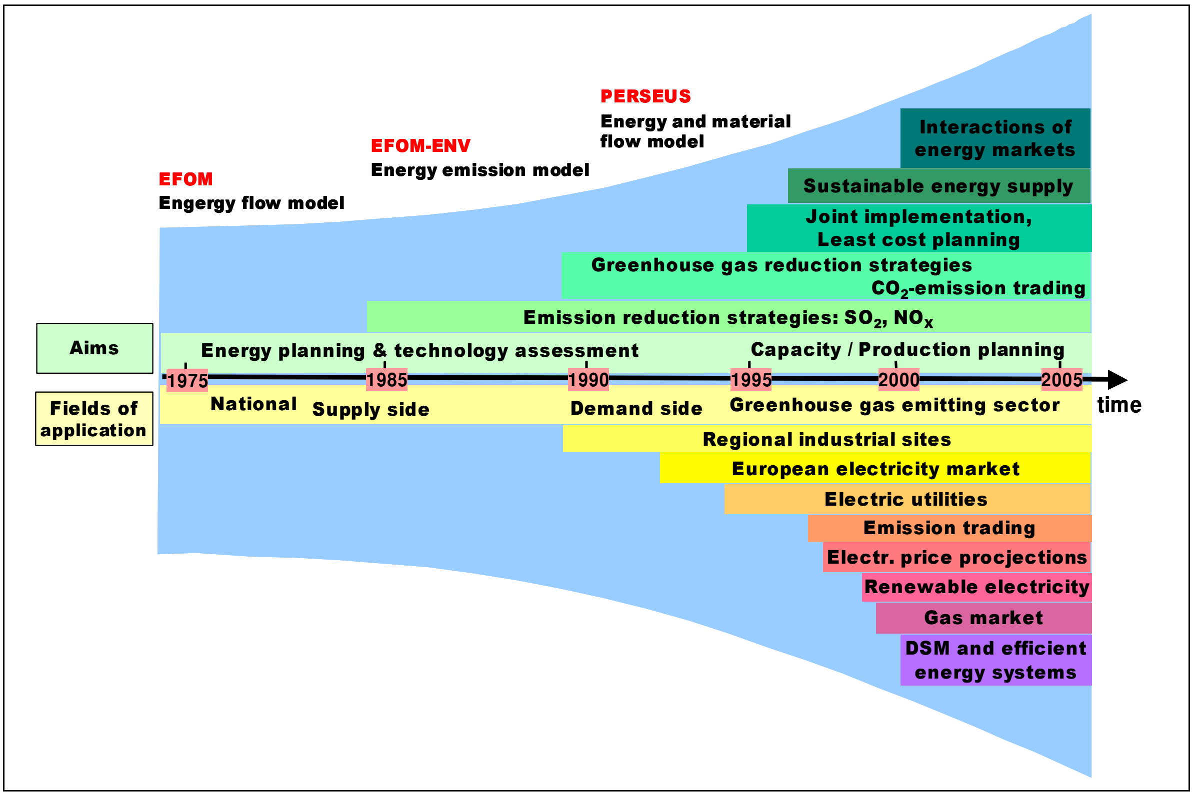

Figure 28: Development of the PERSEUS model family

Versions of the model have also been developed for electricity suppliers to determine cost-optimised strategies for capacity and production planning. The model version with the largest geographical coverage is a multi-regional electricity sector model including 42 European regions [Enzensberger 2003]. It has been developed to determine the effects of an international emission trading scheme on the structure of the European electricity sector and the corresponding prices of emission certificates. On the other end of the scale, a technologically very detailed model for the geographically closely confined area of the Rhine Harbour in Karlsruhe has been developed by [Frank 2003]. In the context of renewable energy sources, the effects of different policy instruments on renewable electricity production in the German state of Baden-Württemberg have been analysed by [Dreher 2001] and the competitiveness of Swiss hydropower by [Möst 2006].

7.2 Outline of the developed modeling approach

Recent liberalisation and re-regulation efforts in the European electricity sector have created new market structures and a new competitive environment. Due to this liberalisation process the entire European electricity market is nowadays relevant for the investment and production planning of electric utilities, as well as for electricity and environmental policy planning processes on both the national and EU-levels. As a result of the greenhouse gas emission allowance trading scheme agreed upon by the European Community [EC 2003c; EC 2003b], appropriate restrictions concerning the production of CO_2 emissions will have to be integrated into the investment and production planning process of electric utilities. Furthermore, on the way to comply with the individual Member States' targets for the utilisation of renewable electricity set in Directive 2001/77/EC different national approaches are used, which need to be assessed in terms of effectiveness and efficiency. Also, cost-effective ways of reaching longer term targets should be highlighted.

It is thus the general objective of the energy system model PERSEUS-RES-E to provide an analysis tool for the quantification of the economic and technological impacts that the policy framework of the required utilisation of renewable sources for electricity generation in combination with the CO_2 reduction commitments may have on conventional and renewable technology choices, certificate (allowance) prices and interregional power exchanges as well as on electricity prices under varying exogenous energy sector framework conditions. PERSEUS-RES-E is an energy and material flow model applying a multi-periodic linear programming approach. The target function requires a minimisation of all decision-relevant costs within the entire modelled energy supply system. This basically comprises fuel supply and transport costs, transmission fees, fixed and variable costs of the physical assets (operation, maintenance, load variation costs, etc.) as well as investments for new plants. The relevant techno-economic characteristics of the real supply system have been considered by implementing further equations covering technical, ecological and political restrictions. The most important technical restrictions, common also to the other models of the PERSEUS family, are:

- Physical energy and material balances: match of demand and supply taking into account storage options and time structures of electricity and heat demand (load profiles).
- Capacity restrictions: transmission capacities, availability of installed capacities, (de)commissioning restrictions, technical lifetime of physical assets.
- Power plant operation: maximum / minimum hours of full load operation, fuel options, cogeneration options, load variation restrictions.

The consideration of transmission capacities and losses as well as transmission fees ensures a realistic representation of the real power exchange characteristics within the model. Further, given the obviously strong interdependencies between electricity and CO_2 markets, the linkage needs to be adequately reflected by the chosen modelling approach. In order to analyse the impact of the emission trading scheme on the physical electricity market, a second market layer, i.e. the certificate market, is an integrated part of the model.

Every regional supply system consists of a different set of physical power and heat generating facilities offering different operation modes and options (availability, load variation characteristics, costs, and the appropriate CO_2 emission factors). Moreover, the total amount of emission allowances, i.e. the respective emission reduction targets, also varies between the different countries and regional energy supply sectors. So, any power exchange directly impacts emission balances and subsequently available emission allowances. Furthermore, the direct links between power or heat generation and CO_2 emissions result in complex (price) interdependencies between the electricity and the certificate market[115].

Available mid-term potentials for renewable electricity generation as well as the costs for the wide range of possibilities for the utilisation of these resources are integrated into the model. Cost effective ways to reach given targets can thus be evaluated and the effectiveness and efficiency of currently applied incentive mechanisms can be judged, as well as the interactions of renewable electricity use with conventional electricity generation and the CO_2 certificate market assessed.

The main output of the optimisation using the PERSEUS methodology is a sector-wide cost-minimised energy system following a normative approach. That means it is based on an economic assessment of measures not from the point of individual actors in the sector, but makes statements on which arrangements should be realised from a sectoral point of view in order to make the sector development as efficient as possible.

7.3 Mathematical description of the model

7.3.1 Structural elements, parameters, and variables of the model

The multi-periodic energy and material flow model PERSEUS-RES-E provides a detailed representation of the existing European electricity supply system with its specific techno-economic characteristics and constraints. The basic model structure corresponds to a directed graph, whose edges represent the different energy and material flows within the system, whereas the nodes stand for different actors with their energy conversion technologies. Additional distribution nodes represent alternative grid and market structures.

The model comprises a large variety of different fossil (e.g. gas, coal, lignite) and non-fossil fuel resources (e.g. nuclear), including renewable energy resources (wind,

[115] The CO_2 certificate market has been integrated into this linear programming model by a set of additional equations (see [Enzensberger 2003]), with the *sectoral balance* and the *trading equation* representing the core of the modelled emission trading. Basically, the trading volume of emission rights for each sector (representing the surplus or deficit of emission rights that enters the trading equation) is determined for each sector by the difference of actual emissions of the sector in that period and the emission rights of the sector in the respective period. Furthermore, penalised emissions that are not covered by emission rights need to be subtracted, while surplus emission rights that are not needed, but excluded from trading (e.g. due to trade limitations), are added to the balance.

solar, biomass, waste, etc.), which together represent the sources of the graph. The connection of all energy producers within the system to these resources by separate energy and material flows permits the consideration of regional fuel supply characteristics like upper or lower flow limits, prices, or transport costs. Furthermore, fuel availability constraints of indigenous fuels like coal or lignite are considered on the level of regions, companies, or even on a single plant level.

The model architecture is built up by a total number of six basic structural elements on different hierarchic levels (see Figure 29).

Regions ($reg \in REG$) as the highest hierarchy level classify the whole system into geographically determined subsystems. Each of these subsystems describes the power supply system of a specific European country or a region of a country.

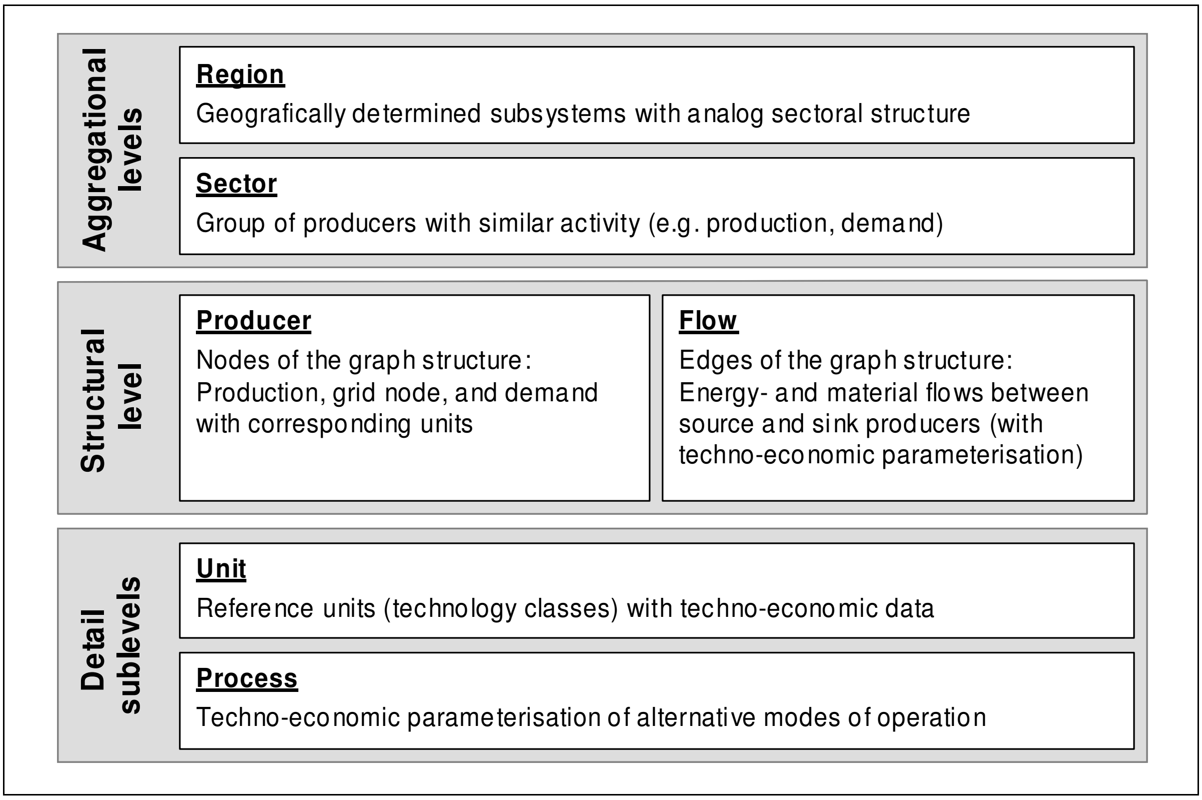

Figure 29: Model elements and hierarchy levels of the model structure

Within each region, different **sectors** ($sec \in SEC$) are distinguished, as for example the fuel supply sector, power supply by utilities, or the final energy demand. Both, regions and sectors, are aggregate entitites above the underlying model structure, which are used to pool the elements of the energy system in a structurally reasonable way, and whose level of aggregation can be adapted to the purpose and the scope of the model. In the case of PERSEUS-RES-E the sectors represent the elementary parts of the electricity supply system (e.g. fuel supply, generating capacities, transmission grid, and energy demand) within each region. Each sector is uniquely assigned to one region, and each producer is assigned to exactly one sector in this strictly hierarchical structure

Together with the **flows** (e.g. of energy carriers $ec \in EC$), the **producers** ($prod \in PROD$) represent the core structural level of the model, i.e. the directed graph. The producers represent the nodes of the graph structure and are interconnected by flows. The flows connecting the different producers are uniquely defined by the producer at their source, the type of material or energy transported, and the producer to which they are directed (sink).

Producers contain transport or conversion **units** ($unit \in UNIT$, e.g. power plants), typically of the same or a similar technology type as these units use the same input energy carrier flows and produce the same or similar output energy flows.

On the lowest hierarchical level, **processes** ($proc \in PROC$) within the units characterise the conversion of the energy and material flows within the units. The definition and parameterisation of processes is done according to the type of activity, as e.g. electricity generation in a power plant, energy carrier transport, or electricity transmission. This level is also typically used to distinguish between different operating conditions of a power plant, such as the utilisation of alternative options for energy carrier supply or combinations of energy output, e.g. in CHP (combined heat and power) units.

The basic structure of the PERSEUS-RES-E model, consisting of the model elements described above, is shown in Figure 30 in a generalised overview for a sample region.

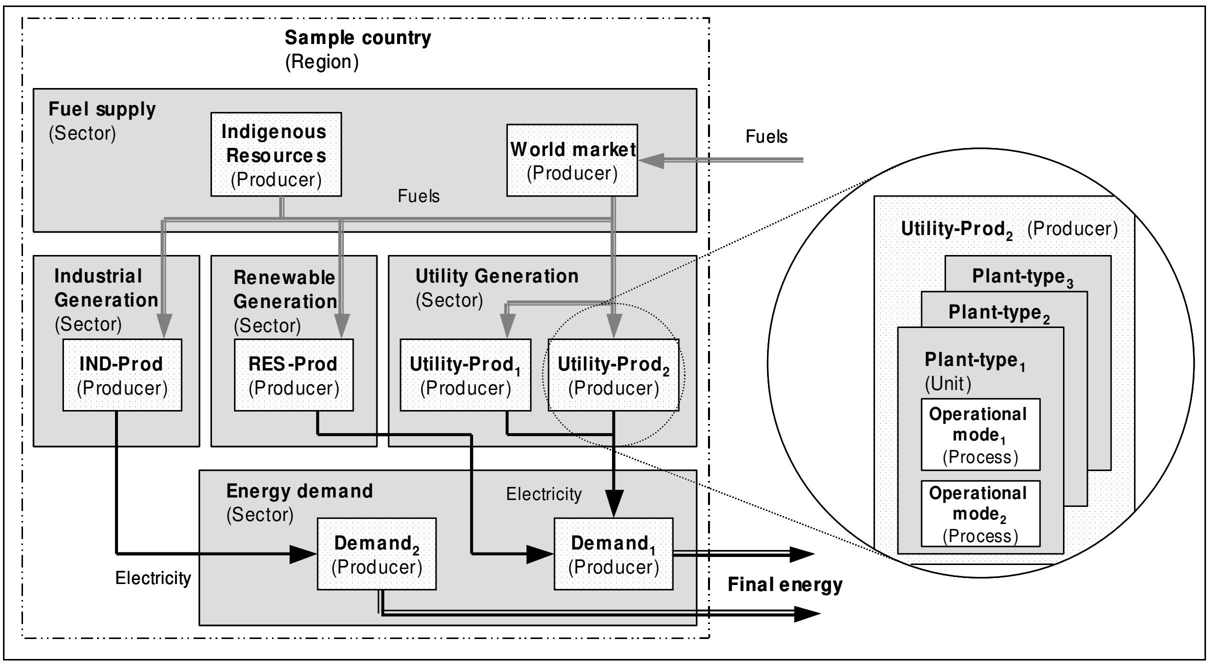

Figure 30: Generalised PERSEUS model structure

7.3.2 System of equations for electricity generation and CO_2 certificate trading

7.3.2.1 Objective function

The optimisation of the system of equations in PERSEUS-RES-E is carried out as a minimisation of the system expenditures necessary to fulfill the exogenously given electricity demand profile. The value of the target function is derived from the sum of all decision-relevant expenditures (see equation (7.1)).

$$
\min \sum_{t \in T} \alpha_t \cdot \left(\begin{array}{l}
\left(\begin{array}{l}
\sum\limits_{imp \in IMP} \sum\limits_{ec \in EC} \sum\limits_{prod' \in PROD'_{imp,ec}} \left(FL_{imp,prod',ec,t} \cdot Cfuel_{imp,prod',ec,t} \right) \\
+ \sum\limits_{prod \in PROD} \sum\limits_{ec \in EC} \sum\limits_{prod' \in PROD'_{prod,ec}} \left(FL_{prod,prod',ec,t} \cdot \left(Cvar_{prod,prod',ec,t} + Cfee_{prod,prod',ec,t} \right) \right) \\
+ \sum\limits_{exp \in EXP} \sum\limits_{ec \in EC} \sum\limits_{prod \in PROD_{exp,ec}} \left(FL_{prod,exp,ec,t} \cdot Cvar_{prod,exp,ec,t} \right)
\end{array} \right) \\
+ \sum\limits_{proc \in PROCGEN} \left(PL_{proc,t} \cdot Cvar_{proc,t} \right) \\
+ \sum\limits_{unit \in UNIT} \left(\begin{array}{l}
\left(Cap_{unit,t} \cdot Cfix_{unit,t} \right) \\
+ \left(NewCap_{unit,t} \cdot Cinv_{unit,t} \right) \\
+ \sum\limits_{seas \in SEAS} \left(LVup_{unit,seas-1,seas,t} + LVdown_{unit,seas-1,seas,t} \right) \cdot Cload_{unit,t}
\end{array} \right) \\
+ \sum\limits_{sec \in TRADESEC} \left(\begin{array}{l}
\left(\left(Emissaux^{+}_{sec,CO_2,t} + Emissaux^{-}_{sec,CO_2,t} \right) \cdot \dfrac{Ctrans_{CO_2,t}}{2} \right) \\
+ \left(EmissPen_{sec,CO_2,t} \cdot Cpen_{CO_2,t} \right)
\end{array} \right) \\
+ \sum\limits_{kyoID \in KYOID} \left(KyoCert_{kyoID,t} \cdot Ckyo_{kyoID,t} \right)
\end{array} \right) \tag{7.1}
$$

In the first group of three summands of the equation all expenditures are contained which are related to supply, transport, and transmission of energy flows (expenditures for fuels, transmission fees, other expenditures). The transmission term especially also includes financial incentives for the use of electricity from renewable sources, modelled as negative expenditures. In the second summand the variable costs of energy transformation are contained, while the third group of summands includes all expenditures on the level of individual units, i.e. investments, fixed operational expenditures as well as load change costs. Further, costs related to the emission trading scheme (cf. chapter 7.3.2.3) like transaction costs, penalties for violations of emission restrictions (caps), and expenditures for the purchasing of external certificates, e.g. from JI and CDM projects, are considered[116].

The specification of the target function as a minimisation of the decision-relevant system expenditures implicates a certain market understanding (perfect market, decisions without delay, no strategic behaviour, etc.) which is explicated in more detail in the critical reflection of the modelling approach in chapter 7.3.3.4. Likewise, the consequences for the price information derived for power and certificate prices in the model calculations are explained in this chapter.

7.3.2.2 Constraints

In the following, technical, economic, and ecological side conditions are introduced. They represent the necessary restrictions of the modelled energy supply system, which need to be obeyed in the system of equations for the integrated planning problem delineated above. One of the key challenges in this context is the treatment of non-linear restrictions, which have to be adequately linearised for an implementation in the LP model[117].

Further, the degree of detail in the model needs to be chosen such as to enable an adequate representation of the technological interrelations in the system. The ambition to achieve the most accurate representation of the technical details of the system must be reconciled with the conflicting restrictions determined by the available computing power, which limits the maximum acceptable size of the model.

7.3.2.2.1 Energy and material flow balances

Energy and material flows, as determined by the laws of physics, constitute the central structure in energy supply systems, which needs to be properly represented in a valid model of the real energy system. Especially the accurate formulation of energy and material flow balances in the nodes of the directed graph's structure (i.e. the producers) is of essential importance in this context. In other words it must be

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[116] An important modelling aspect of the described solution approach is the integrated treatment of three optimisation problems (system expansion planning, capacity production planning, and CO_2 certificate trading), which are often treated separately in other models. In the target function described, the integration of these problem components is achieved by collectively accounting for the corresponding relevant system expenditure components from the three planning areas. Any investments into new generation assets are only made in the case that the expected utilisation determined for these units, i.e. the expected electricity supply in the following periods of the model, can not be achieved more economically by existing units or other expansion options. Analogously, the CO_2 mitigation options, which determine the certificate price in the emission trading scheme, take into account all possibilities for coordinated measures of plant commissioning or decommissioning, process utilisation as well as the purchase or sale of certificates.

[117] This applies in particular also to the modelling of available potentials for renewable electricity generation and the costs for their utilisation. While the assessment of available potentials is independent of time, the evolution of costs to develop these potentials is based on learning and experience, which usually are a function of time. While the determination of the characteristics of these learning processes is difficult to begin with, their integration needs to be based on the realised capacity of a technology and would thus imply that a mixed-integer approach had to be used. Due to the large number of integer variables necessary in the model in this case, such an approach is not feasible for reasons of model size and calculation times.

guaranteed that in each time slot of the modelled time horizon the sum of the inflows of an energy carrier or other materials ec to each producer $prod$ corresponds precisely to the outflows from this producer. Thus, generally, no storage of energy carriers or materials is allowed. For the special case of pumped storage power plants, where this is explicitly required, please refer to the description in section 7.3.2.2.4.

The governing balance in the model is determined by the energy demand as the driving force, which needs to be fulfilled for every time slice of the modelled time horizon (see equation (7.2)). Here it is required that in each time slot the output exp of an energy or material flow of an energy carrier ec in each region reg is greater than or equal to the exogenously given demand $Dem_{reg,ec,t,seas}$ for the energy carrier ec in the region reg in that specific time slot $t,seas$.

$$FL_{prod,ec,exp,t,seas} \geq Dem_{reg,ec,t,seas}$$

$$\forall t \in T; \quad \forall prod \in PROD; \quad \forall ec \in EC_{seas}; \quad \forall seas \in SEAS; \tag{7.2}$$

An important physical restriction of energy and material flow modelling is the guarantee of energy and mass flow balances, which have to be fulfilled for each node of the network in the modelled energy system. The balance condition for each node (i.e. for each producer) implies that the sum of energy and material flows inflows to the producer, considering the conversion efficiencies, must correspond to the sum of outflows.

The left hand side of equation (7.3) includes all inflows (from the sources IMP of the graph) to the considered producer, plus those from other nodes of the graph, $PROD_{prod,ec}$, which are linked to the producer by edges of the graph (i.e. flows). Additionally, the energy provided by the considered producer is accounted for on this side of the balance. The right hand side contains all transmissions to either other producers, or to sinks as well as the consumption of the producer (i.e. the conversion to other energy forms). An analogous equation represents the analogous case for energy carriers without a seasonal flow profile (primary energy carriers)[118].

[118] In this context the term seasonal flow profile refers to a differentiation of characteristic days, each with several time slots. Different from an average annual value these allow to represent interrelations in the model equations as well as the model results that are characterised by diurnal and/or seasonal variations. The term time slot (also called time slice or time segment in the following) characterises the unique combinations of the model time intervals and the model time periods. For example, the time interval ‘spring working day from 08:00 hours until 11:00 hours’ on any spring working day, and the exemplary model time period ‘year 2010’ characterise the unique time slice ‘spring working day from 08:00 hours to 11:00 hours in the year 2010’.

$$\sum_{imp \in IMP} FL_{imp,prod,ec,t,seas} + \sum_{prod' \in PROD_{prod,ec}} FL_{prod',prod,ec,t,seas} + \sum_{proc \in PROCGEN_{prod,ec}} PL_{proc,t,seas} \cdot \lambda_{proc,ec}$$
$$= \sum_{\exp \in EXP} \frac{FL_{prod,\exp,ec,t,seas}}{\eta_{prod,\exp,ec,t}} + \sum_{prod' \in PROD'_{prod,ec}} \frac{FL_{prod,prod',ec,t,seas}}{\eta_{prod,prod',ec,t}} + \sum_{proc \in PROCDEM_{prod,ec}} PL_{proc,t} \cdot \frac{\lambda_{proc,ec}}{\eta_{proc,ec}} \cdot f_{proc,t,seas}$$

$$\forall t \in T; \quad \forall prod \in PROD; \quad \forall ec \in EC_{seas}; \quad \forall seas \in SEAS; \qquad (7.3)$$

Those optimisation variables in the equation system that describe the utilisation rates of flows or processes are utilised for the annual values as well as for the temporally higher differentiated values of individual time slots of characteristic days. Equation (7.4) ensures that the annual value of the flow levels corresponds to the sum of the flow levels in the single time slots. An analogous equation ensures that this correspondence is maintained for the utilisation of processes.

$$\sum_{seas \in SEAS} FL_{prod,prod',ec,t,seas} = FL_{prod,prod',ec,t} \qquad (7.4)$$

$$\forall t \in T; \quad \forall prod \in PROD; \quad \forall prod' \in PROD'; \quad \forall ec \in EC$$

7.3.2.2.2 Energy and material flow constraints

All of the energy and material flows within the PERSEUS-RES-E model can be limited by either upper or lower bounds. Moreover, a fixed flow level can be specified. Any of these constraints can be specified either in relation to the annual amount of energy or material, or limiting the flow level in individual time segments. As the flow levels are variables of the optimisation problem they can be directly assigned upper or lower bounds ($FLmax_{prod,prod',ec,t,seas}$, $FLmin_{prod,prod',ec,t,seas}$) or a fixed flow level $FLlev_{prod,prod',ec,t,seas}$, respectively. The bounds thus do not need to be explicitly integrated as additional equations.

7.3.2.2.3 Capacity restrictions

Simultaneously with the energy and material flows also the evolution of conversion capacities in the power plant portfolio is optimised in the model. Contrary to the seasonal optimisation of flows, i.e. for each time slot of the model, the capacity variables are defined for each period, which implies that the capacity restrictions are also applied per period.

Here, a differentiation between existing capacities and capacity expansion options is necessary, which is achieved by using the capacity parameters $CapRes_{unit,t}$ and $CapMax_{unit,t}$. For the so-called residual capacity, i.e. the remaining capacity of a unit which is already installed, and thus is available without any additional investment necessary, is described by $CapRes_{unit,t}$. Usually, the residual capacities consist of units that have been commissioned before the base year of the model. Based on the commissioning date of a unit, its expected lifetime, or the knowledge of a decommissioning schedule put up by the operator, according residual capacities can be specified for each period t in the model. $CapMax_{unit,t}$ is a complementary parameter, which is used to specify the highest possible installed capacity of a unit in a period t and thus limits a potential expansion of an existing unit or the commissioning of new capacity.

Two cases can be distinguished:

$CapMax_{unit,t} = CapRes_{unit,t}$: Generally this is the case for existing units, any further expansion or construction of new capacity is ruled out.

$CapMax_{unit,t} > CapRes_{unit,t}$: In this case the commissioning of new capacity up to the difference of $CapMax_{unit,t} - CapRes_{unit,t}$ is allowed to be chosen in the optimisation. A value of $CapRes_{unit,t} = 0$ usually applies for expansion options, i.e. those types of units that are available for future commissioning (either as additional capacity or as replacement for decommissioned capacity).

The value of the capacity variable $Cap_{unit,t}$ in a period t results from the addition of the residual capacity and the sum of all capacity expansions realised by the optimisation since the base year, including the current time period, as shown in equation (7.5).

$$Cap_{unit,t} = CapRes_{unit,t} + \sum_{t'=(t-TLT_{unit})}^{t} CapNew_{unit,t'} \qquad \forall unit \in UNIT; \quad \forall t \in T \qquad (7.5)$$

Analogously to the commissioning of new units, the decision to decommission existing units before the end of their technical lifetime is also a result of the optimisation.

When defining scenarios, both the total installed capacity of a unit $unit$ in the year t (described by the capacity variable $Cap_{unit,t}$), as well as the newly constructed capacity (the value of the second capacity variable $CapNew_{unit,t}$) can be limited by upper and / or lower bounds[119]. For a minimum total capacity $CapMin_{unit,t}$ can be specified, or, as already mentioned above, $CapMax_{unit,t}$ for the upper limit of the total installed capacity. The maximum of the capacity that may be added to a unit in a year t can be limited by $MaxAdd_{unit,t}$.

While capacity restrictions are usually applied on the level of units, they can also be specified on higher aggregation levels, which simplifies the consideration of possible political restrictions, as e.g. a maximum allowed total capacity of nuclear power plants in a region (equation (7.6)).

$$NucMaxCap_{reg,t} \geq \sum_{unit \in NUC_{reg}} Cap_{unit,t} \qquad \forall t \in T; \quad \forall reg \in REG \qquad (7.6)$$

[119] These side conditions, called ‘variable bounds’, can be implemented directly in GAMS.

7.3.2.2.4 Restrictions of process utilisation

Further optimisation variables of the modelled problem are the activity levels of a unit $PL_{proc,seas,t}$, which also can be directly limited according to technological conditions. All process activities are limited by the installed capacity and the average availability of the respective units. Equation (7.8) ensures that this limitation is respected for processes with a seasonal temporal differentiation, while equation (7.7) represents the analogous restriction for processes without a seasonally differentiated representation.

$$Cap_{unit,t} \cdot Avai_{unit,t} \cdot h_{year} \geq \sum_{proc \in PROC_{unit}} \left(PL_{proc,t} \cdot \Omega_{proc,t} \right) \quad \forall t \in T; \quad \forall unit \in UNIT \tag{7.7}$$

$$Cap_{unit,t} \cdot Avai_{unit,t} \cdot h_{seas} \geq \sum_{proc \in PROC_{unit}} \left(PL_{proc,seas,t} \cdot \Omega_{proc,t} \right) \quad \forall t \in T; \quad \forall unit \in UNIT; \quad \forall seas \in SEAS \tag{7.8}$$

Further, minimum or maximum full load hours can be specified for each process. The restrictions in equation (7.9) and equation (7.10) ensure that the annual production of a process does not exceed or fall short of a theoretical level based on the capacity and the maximum/minimum full-load hours.

$$\frac{VlhMax_{proc,t}}{h_{year}} \cdot Cap_{unit_{proc},t} \geq PL_{proc,t} \cdot \Omega_{proc,t} \qquad \forall proc \in PROC; \forall t \in T \tag{7.9}$$

$$\frac{VlhMin_{proc,t}}{h_{year}} \cdot Cap_{unit_{proc},t} \leq PL_{proc,t} \cdot \Omega_{proc,t} \qquad \forall proc \in PROC; \forall t \in T \tag{7.10}$$

Also on higher aggregation levels important physical restrictions can apply, such as the politically motivated nuclear phase-out in Germany. Equation (7.11) ensures that the power production from German nuclear power plants does not exceed the remaining production of $NucMaxProd_{Germany}$ = 2623.3 TWh fixed in the phase-out declaration.

$$\sum_{t \in T} \sum_{unit \in NUC_{Germany}} \sum_{proc \in PROC_{unit}} PL_{proc,t} \cdot \lambda_{proc,elec} \cdot years_t \leq NucMaxProd_{Germany} \tag{7.11}$$

Load variation

Regarding their capabilities for load variation, there are significant differences between the commonly used technologies for power and heat generation. Typical base load power plants like lignite or nuclear fired capacities are quite limited in terms of the possible gradient and the frequency of load changes. In order to ensure that the electricity demand profile can be met as accurately as possible, intermediate load (mostly coal power plants) and peak load capacities (like e.g. gas turbines or gas fired combined-cycle processes) with better abilities to vary their load need to be utilised.

Within the model, a differentiation of load change characteristics can be achieved in several ways. For units where load variations can be largely excluded or shall be excluded by definition, equation (7.12) stipulates that the power output of a certain process of the unit is kept constant throughout a season. Analogous to the restriction for spring given in equation (7.12), the restriction is implemented for the remaining seasons of the year as well.

$$\frac{PL_{proc,seas,t}}{h_{seas}} = \frac{\sum_{seas \in SPRING} PL_{proc,seas,t}}{\sum_{seas \in SPRING} h_{seas}} \qquad \forall proc \in BASEPROC; \quad \forall seas \in SPRING \tag{7.12}$$

For most power plant types, however, a more differentiated representation of the individual technologies' abilities for load change is necessary, which is possible to realise e.g. by the introduction of load change costs[120]. By registering the changed load between any two time slots in the model and weighting it with the number of transitions between the two time slots $No_{seas-1,seas}$ a cumulated load change is derived. Multiplied by the load change costs of the specific unit, it is taken into account in the objective function of decision relevant expenditures, which are to be minimised. Instead of a free variable, two positive variables ($LVup_{unit,seas-1,seas,t}$, $LVdown_{unit,seas-1,seas,t}$) are used in equation (7.13) to compose the absolute value[121] of the load change for each unit, which, multiplied by the load change costs of this unit, enter the objective function (cf. chapter 7.3.2.1).

For each technology type characteristic load change costs can be considered, which range from marginal values for units with very flexible output like (pumped) storage power plants up to prohibitively high values for some nuclear power plants.

$$\begin{aligned} & LVup_{unit,seas-1,seas,t} - LVdown_{unit,seas-1,seas,t} = \\ & No_{seas-1,seas} \cdot \left(\sum_{proc \in PROC_{unit}} \left(\left(\frac{PL_{proc,seas,t}}{h_{seas}} - \frac{PL_{proc,seas-1,t}}{h_{seas-1}} \right) \cdot \frac{1}{\eta_{proc,t}} \right) \right) \\ & \forall t \in T; \quad \forall seas \in SEAS; \quad \forall unit \in UNIT \end{aligned} \tag{7.13}$$

[120] Alternatively, a limitation of load change rates differentiated by technologies can be implemented, as has been done e.g. by [Fichtner 1999, p. 75].

[121] Cf. [McCarl et al. 1997] for explanations on how to represent absolute values in linear optimisation models.

Heat extraction

Besides the installed power generating capacity, also the maximum possible heat extraction is implemented for each class of thermal power plants. Based on historical data, the average annual heat extraction is determined, which corresponds to a maximum number of full load hours, at which the heat extraction process can be operated. Equation (7.14) ensures that this restriction is obeyed, distinguishing between different types of heat.

$$\sum_{proc \in HEATPROC_{unit,heattype}} \left(\frac{VlhMax_{proc,t}}{h_{year}} \cdot Cap_{unit,t} \cdot \frac{\lambda_{proc,heattype}}{\Omega_{proc,t}} \right) \leq \sum_{proc \in HEATPROC_{unit,heattype}} \left(PL_{proc,t} \cdot \lambda_{proc,heattype} \right)$$

$$\forall unit \in UNIT, \quad t \in T \tag{7.14}$$

Moreover, the cumulated heat production from all heat generation processes has to correspond to the temporal profile of heat demand for a certain heat type $HGF_{unit,t,seas,heattype}$ (cf. equation (7.15)) in each region, i.e. heat production needs to follow heat demand. This needs to be ensured independently from the power production that may take place in the same unit.

$$\left(\sum_{\substack{proc \in \\ HEATPROC_{unit,heattype}}} \left(PL_{proc,t,seas} \cdot \lambda_{proc,heattype} \right) \right) = \left(\sum_{\substack{proc \in \\ GENPROC_{unit,heattype}}} \left(PL_{proc,t} \cdot \lambda_{proc,heattype} \right) \right) \cdot HGF_{unit,t,seas,heattype}$$

$$\forall unit \in UNIT; \quad \forall t \in T; \quad \forall seas \in SEAS; \quad \forall heattype \in HEAT$$

with: $$HGF_{unit,t,seas,heattype} = \frac{\sum_{proc \in DEMPROC_{reg_{unit},heattype}} \left(PL_{proc,t,seas} \cdot \lambda_{proc,heattype} \right)}{\sum_{proc \in DEMPROC_{reg_{unit},heattype}} \left(PL_{proc,t} \cdot \lambda_{proc,heattype} \right)} \tag{7.15}$$

Pumped storage

Pumped storage power plants perform a dual task in the generation system, acting either as producers or consumers (sources or sinks) of electricity, with the storage capacity as a direct link between those two functionalities. The objective of an operation of pumped storage facilities is usually a smoothing of the load profile of conventional power plants by using abundant base load capacities in times of low system load (usually at night) to provide part of the peak load power in times of high electricity demand during the day. This 'refinement' of base load power, manifested in the price difference between peak load and base load power, ensures that the unavoidable storage losses are (over)compensated. Furthermore, the load changing behaviour of pumped storage power plants is very flexible, which makes them well suited to provide ancillary services as frequency stabilisation and reserve capacities.

In the model, the operation modes pumping and turbine operation are implemented as two separate producers (assigned to each other via the table *PMAP*) with the ability either to consume power for the pumping of water or to generate power from the stored water. The connection of both functions via the storage capacity is ensured by equation (7.16), which stipulates that the amounts of water pumped to and drained from the storage facility during one year are equal[122].

$$\sum_{exp \in EXP} FL_{prod',exp,to\text{-}storage,t} = \sum_{imp \in IMP} FL_{imp,prod,from\text{-}storage,t}$$
$$\forall t \in T; \quad \forall (prod; prod') \in PMAP_{PROD,PROD'} \tag{7.16}$$

7.3.2.3 Emission trading scheme

Next to the modelling of power generation options and the interregional electricity trade, the functionalities of the European Emission Trading Scheme are taken into account in the model. This is achieved by integrating further equations and inequations as well as an amendment of the target function. In the following the underlying concept for the modelling of the trading scheme and the basic equations shall be introduced to give an overview of the principal modelling approach. For a detailed elaboration on various design options of the ETS, reference is made to [Enzensberger 2003].

Analogously to the stipulations in the Emission Trading Directive [EC 2003b], also in the model a quantity-based approach is applied to introduce restrictions on the formerly freely available commodity CO_2 emission rights.

As an adequate trade-off between the desirable level of detail and the model size with the resulting calculation times the certificate trade implemented in the model is realised among sectors as the obliged participants[123]. However, a trade between regions is sketched in the following explanatory example for reasons of clarity. It is also on this regional level where the possibilities for an interregional electricity exchange lead to interactions of the certificate trade with power production.

[122] For the Alpine region as well as for Scandinavia (especially Norway), the chosen linear modelling approach and the reduction to a limited number of hydro power plant types implicate a major simplification of the complexity of real hydro power regimes. A more detailed modelling of hydro power schemes (cascades) and the hydrological restrictions determining their operation (seasonal inflow and outflow, storage, water levels) can be realised using mixed-integer linear programming approaches (cf. [Graeber 2002], [Möst 2006]). With regard to the model size, compromises are necessary in these models concerning the level of detail for other technology classes or for the possible geographic scope, which is due to the large amount of binary and/or integer variables involved. The complementarity of wind and hydropower in the context of scheduling has also been assessed by [Vogstad 2004].

[123] Due to the model size and data availability, individual companies were not distinguished. While this would not be a problem from a modelling point of view, an adequate compromise has to be found between the level of detail in the model and the model size with the corresponding calculation times.

Caused by the process activities of the energy conversion units in each region, CO_2 emissions are released, which are to be limited and managed by the emission trading scheme. For each region reg, an exogenously given quantity of emission rights $EmissRightsCO_{2,reg,t}$ is allocated and compared to the region's total emission volume $EmissVol\ CO_{2,reg,t}$. From the difference of both values the trade volume $\Delta Emiss\ CO_{2,reg,t}$ of each region is determined. By the trading equations in the model it is ensured that the individual trade volumes can be balanced, i.e. the supply and demand of emission rights are matched.

In the examplary illustration in Figure 31, three model regions with their power plant portfolio and their characteristic load profile are shown. According to the target function described in section 7.3.2.1 the power plants are operated with the objective of a cost-minimised coverage of the load requirements. As the regions are interconnected by transmission lines on the one hand and via the certificate trading scheme on the other, the changed cost structure in the regions resulting from the individual emission allocations and the available CO_2 reduction options may cause a reallocation of power production, but only within the framework and limitations of the existing transmission capacities and possible emission trading restrictions.

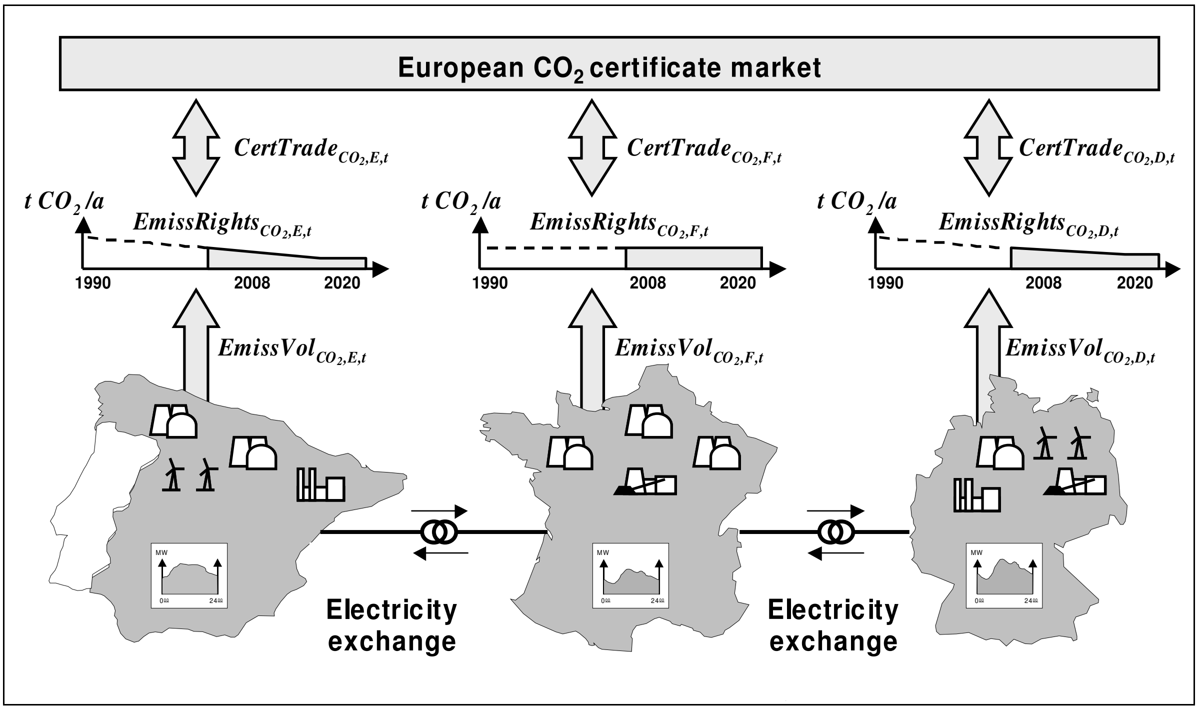

Figure 31: Interdependence of interregional electricity exchange and certificate trade (cf. [Enzensberger 2003])

7.3.2.3.1 CO_2 balance equations

For each sector the corresponding CO_2 emission volume $EmissVol_{sec,}\ CO_{2,t}$ is determined according to the balance in equation (7.17), i.e. as the sum of emissions that can be assigned to the processes and flows of the respective sector sec. The process emissions are calculated as the product of the activity levels of the processes in the considered sector and the specific CO_2 emission factor of the respective process. Analogously, flow emissions can be considered in the model[124].

$$EmissVol_{\sec,CO_2,t} = \sum_{proc \in PROC_{\sec}} PL_{proc,t} \cdot EmissProc_{CO_2,proc,t} + \sum_{prod' \in PROD'_{\sec}} \sum_{ec \in EC} \sum_{prod \in PROD_{prod',ec}} FL_{prod,prod',ec,t} \cdot EmissFlow_{CO_2,prod,prod',ec,t} \quad (7.17)$$

$$\forall t \in T; \forall \sec \in SEC$$

The certificate trading activity of a sector, i.e. the purchase (positive values) or sale of emission rights (negative values), represented by the variable $\Delta Emiss_{sec,\ CO2,t}$, is based on the difference of the sector's emission volume $EmissVol_{sec,\ CO2,t}$ on the one hand and its emission rights $EmissRights_{sec,\ CO2,t}$ on the other hand. Two additional components complete the emission trading balance in equation (7.18). One is the variable $EmissPen_{sec,\ CO2,t}$, which represents additional emissions not covered by emission rights. These emissions are subject to a (usually prohibitively high) penalty in the target function. Such additional emissions are thus only chosen in the case of extreme CO_2 restrictions, where the certificate price, i.e. the marginal costs of CO_2 abatement, surpasses the penalty threshold in the system or individual regions. In this case the deliberate violation of CO_2 restrictions makes sense economically, and the availability of penalised emissions ensures that the optimisation problem remains solvable even under extreme circumstances. The other additional variable $EmissLoss_{sec,\ CO2,t}$ represents excess emission rights that may not be sold to the market due to exogenously given trade restrictions[125].

$$\Delta Emiss_{\sec,CO_2,t} = EmissVol_{\sec,CO_2,t} - EmissRights_{\sec,CO_2,t} + EmissLoss_{\sec,CO_2,t} - EmissPen_{\sec,CO_2,t}$$

$$\forall t \in T; \forall sec \in TRADESEC \quad (7.18)$$

---

[124] Especially for natural gas, which is the favourite conventional fuel option to mitigate greenhouse gas emissions in electricity generation, previous worst case estimations (e.g. by [Rabchuk et al. 1991]) indicated high methane emissions in the supply chain. However, more recent assessments by [Popov 2001] and [Lechtenböhmer et al. 2005] based on measurement campaigns prove that with around 1% of the produced volume of natural gas the amount of methane released from exploration and transport activities of Russian gas to the Federal Republic of Germany is much lower than anticipated. Apart from methane, about twice the effective amount of greenhouse gases is released as CO_2. These emissions are caused by the consumption of natural gas and power in gas turbines and electric motors used for the transport of the natural gas in the pipelines. Altogether, the indirect greenhouse gas emissions of the natural gas supply chain are thus at a comparable level with those of the supply chain of oil or hard coal.

[125] Such restrictions could e.g. be implemented in order to limit the unrestricted trading of emissions from countries with very inexpensive mitigation options, especially in Central and Eastern Europe. Also the so-called 'hot air', i.e. excess emission rights resulting from the economic breakdown of Eastern European economies, has caused concerns that the certificates generated could flood the certificate market, which would render efficient mitigation measures in Western European countries redundant.

The resulting certificate trading volume is the basis for the trading equations described in the following.

7.3.2.3.2 CO_2 emission trading equations

In accordance with the concept of the intgrated certificate trade (cap and trade), the basic trading equation (equation (7.19)) stipulates that the cumulated supply of certificates equals the cumulated demand, i.e. the trading volumes of all sectors participating in the certificate trade, need to add up to zero.

This basic equation can be amended according to the design options of the certificate trading scheme to incorporate the purchase of external certificates and trade restrictions.

$$\sum_{\sec \in TRADESEC} \Delta Emiss_{\sec, CO_2, t} = 0 \qquad (7.19)$$

$$\forall t \in T$$

The so called Linking Directive [EC 2004a] regulates the recognition and purchase of external certificates, i.e. so called Kyoto certificates from JI or CDM projects. These additional certificates represent a relief for the cap and trade system, as they increase the total amount of available emission rights for the obliged European emitters. The supply of external certificates is modelled as a step-wise supply curve[126] of a certain number of certificate contingents $kyoID$, each of which is characterised by the available quantity $KyoMax_{kyoID,t}$ as well as the corresponding price $Ckyo_{kyoID,t}$, at which the contingent is available. The trading equation can be modified accordingly by the variable $KyoCert_{kyoID,t}$ to take into account the purchase of additional certificates from each contingent $kyoID$ (equation (7.20)).

$$\sum_{\sec \in TRADESEC} \Delta Emiss_{\sec, CO_2, t} = \sum_{kyoID \in KYOID} KyoCert_{kyoID,t} \qquad (7.20)$$

$$\forall t \in T$$

Moreover, it must be ensured that the available amount of certificates from each contingent is limited to the maximum size of the contingent (equation (7.21)).

$$KyoCert_{kyoID,t} \leq KyoMax_{kyoID,t} \qquad (7.21)$$

$$\forall t \in T; \forall kyoID \in KYOID$$

Expenditures for the acquisition of external certificates are decision-relevant and are thus considered in the target function (see the last term of the sum in equation (7.1)).

[126] An analogous methodology is also used for the representation of renewable potentials, see Chapter 8.6.1.

As a further design option of the certificate trade, the banking of certificates is taken into account in the equation system. In this case, equation (7.22) replaces equation (7.20). The transfer of certificates not used in one period to the following period is allowed within each banking period $bpID$, which is specified by its start year $bplow_{bpID}$ and end year $bpup_{bpID}$. While the banking option is allowed, the (undesirable) borrowing of certificates is excluded. For the first year of a banking period, equation (7.22) stipulates that the total emissions in the market do not exceed the sum of the allocated emission rights for that year, while for the following years the restriction is applied to the cumulated emissions and emission rights from the start year up to the current year.

$$\sum_{t'=bplow_{bpID}}^{t} \sum_{\sec \in TRADESEC} \Delta Emiss_{\sec, CO_2, t'} \leq \sum_{t'=bplow_{bpID}}^{t} \sum_{kyoID \in KYOID} KyoCert_{kyoID, t'} \qquad (7.22)$$

$$\forall t \in \left[bplow_{bpID}, bpup_{bpID} \right] \; ; \; \forall bpID \in BPID$$

7.3.2.3.3 Trade modalities

While the above equations define the core mechanisms of certificate trading, further modalities of the tradig scheme can be regulated by additional design features. These include trade restrictions (to prevent or at least mitigate extreme tendencies in the development of the market, e.g. the sale of hot air), transaction costs[127], and penalties for non-compliance. These are integrated as additional restrictions and extensions of the target function. For a detailed elaboration on these options please refer to [Enzensberger 2003].

In the following, only the possible penalty mechanisms will be described. Defiances of emission reduction requirements, i.e. emissions exceeding the amount covered by allowances, can be fined with a penalty $Cpen\ CO_{2,t}$. in order to enforce the compliance of actual emissions with the granted emission allowances. The penalty specifies the amount of money that an obliged emitter has to pay for each emission unit that can not be covered by own or purchased emission allowances at the end of an accounting period. Thus, the objective function includes an according cost term, as shown in equation (7.1). Emissions in excess of the allocated allowances can either occur if the available technologies need more emission rights than available on the certificate market to fulfil the energy demand; or if the cheapest available option to further reduce CO_2 is more expensive than the penalty. In the latter case, with marginal CO_2 reduction costs exceeding the penalty price, the penalty is the economically favoured option and thus also sets the maximum price for CO_2 certificates. Moreover, the implementation of the penalty option also ensures that the model can be solved even under extreme mitigation obligations.

[127] Cf. e.g. [Michaelowa et al. 2003]. A quantitative analysis of transaction costs related to JI projects can be found in [Rentz et al. 1998, p. 46 ff.].

Furthermore, liberatory and non-liberatory modalities of penalty payment can be distinguished. In the case of a liberatory penalty, only the payment has to be made for each excess tonne of CO_2 emissions, while the market participants are 'liberated' from the original reduction obligation. In this case, the term $EmissPen_{sec,t-1}$ is set equal to zero with the beginning of the upcoming period, i.e. not affecting the allocated emissions $EmissAlloc_{sec,t}$ for the new period. In the case of a non-liberatory penalty, as modelled in equation (7.23), the reduction obligation persists, even if the penalty has been paid, i.e. the excess emissions $EmissPen_{sec,t-1}$ of the previous period must additionally be mitigated in the following period.

$$EmissAlloc_{\sec,t} = EmissRights_{\sec,t} - EmissPen_{\sec,t-1}$$
$$\forall sec \in TRADESEC, t \in T \qquad (7.23)$$

7.3.3 Utilisation of renewable electricity

7.3.3.1 Targets for renewable electricity use

Two different options for target specification and compliance can be distinguished. Firstly, a specification of individual targets for each country can be realised, as stipulated in Directive 2001/77/EC, and connected to the requirement that the corresponding amount of renewable electricity must be produced within each country from the indigenously available renewable energy sources. In a second design option, the stipulated production targets can be combined with the possibility for an interregional trading scheme. This latter design option, in analogy to the CO_2 certificate trading scheme, allows for the fulfilment of RES-E production obligations anywhere within the obliged group of regions, wherever it is most cost-effective.

7.3.3.1.1 National targets

By the following restriction (equation (7.24)) it is ensured that in a year t at least the specified amount of power $RESe\text{-}target_{reg,t}$ is produced from renewable sources within a region reg. Due to the minimisation of system expenditure specified in the objective function, this stipulation delivers the most cost-efficient solution for the compliance with the required target in each country.

$$\sum_{ec \in EC_{RES}} \sum_{proc \in ELECPROC_{reg,ec}} PL_{proc,ec,t} \cdot \lambda_{proc,ec,t} \geq RESe\text{-}target_{reg,t}$$
$$\forall\ reg \in REG,\ \forall\ t \in T \qquad (7.24)$$

The resulting solution corresponds in principle to a perfect national green certificate market within each of the countries, without transaction costs or other efficiency losses. An analysis of the results thus allows the identification of the most expensive RES-E potentials realised, which are necessary to fulfil the targets in each country and can give valuable information on which renewable energy carriers should be promoted to achieve a cost-minimised compliance with the targets of the RES-E Directive.

7.3.3.1.2 Cumulative European targets plus Green Certificate Trade

In the case of an interregional European Green Certificate Trading scheme the sum of the RES-E production obligations of the individual countries can be allocated freely among the participating countries in order to achieve a least cost compliance with the cumulated target. This stipulation is expressed in equation (7.25).

As in the case of CO_2 emission reductions the analysis of marginal costs of target compliance also here allows the derivation of indicative values for the prices of green certificates, which in an unrestricted market can reach an equilibrium and reflect the utilisation costs of the most expensive renewable potentials necessary for compliance with the cumulated European target.

The different design options (transaction costs, penalties, etc.) already described for the certificate trading scheme in section 7.3.2.3 can also be transferred to a GCT scheme[128].

$$\sum_{reg \in REG_{RES-E}} \sum_{ec \in EC_{RES}} \sum_{proc \in ELECPROC_{reg,ec}} PL_{proc,t} \cdot \lambda_{proc,t} \geq \sum_{reg \in REG_{RES-E}} RESe\text{-}target_{reg,t} \qquad \forall\, t \in T \tag{7.25}$$

7.3.3.1.3 Technology specific targets

Based on the same principle, not only country-specific, but also technology-specific quotas can be integrated into the model. In this case it is required that a certain amount of electricity is produced from a specific source, e.g. solid biomass, while other sources may have different quotas. By setting quotas for specific technologies or technology bands, it can be ensured that also less competitive technologies are further developed under a quota scheme. At the same time, the possibility of windfall profits is limited. These can occur if a high but not technology-specific quota is set, where the most expensive technology determines the marginal price for the green certificates. In this case, the producers of electricity from considerably cheaper sources would make large windfall profits, compromising the economic efficiency of the quota scheme. On the other hand, if an unspecific, general quota is set too low, only the technologies closest to profitability will be used, while less developed and more expensive technologies will not be further developed, compromising the long-

[128] Although hard to quantify in absolute terms, it can be expected that transaction costs for a more competition-oriented green certificate trading scheme are higher than when using fixed feed-in tariffs. While the remuneration for planned projects is guaranteed under a feed-in regulation, the efforts to merge supply and demand of green certificates will cause market transaction costs for the obliged parties. Similarly, the costs incurred in the planning process of unaccepted bids in tendering schemes have to be covered and can be expected to be included in future bids.

term dynamic efficiency of the scheme. Similar to the general renewable quota, technology-specific quotas can be set on national or on a European level.

Due to the multitude of possible design options and the consequences this has for comparability, the scenario analysis in chapter 9 includes no scenarios with technology-specific quotas. In fact, the expansion paths for the different renewable energy carriers that are derived when more or less ambitious national or European target quotas are specified in the model calculations can be interpreted as the economically optimal technology-specific quotas to achieve the given overall target.

For an effective and efficient functioning of the quota system principle, so called renewable energy technology portfolio subsets could be defined e.g. specifically for each country, including the potentials of different technologies that show comparable generation cost characteristics.

7.3.3.2 Financial incentives for renewable electricity use

Instead of specifying targets for renewable electricity utilisation shares to be achieved and deriving information on the least cost options to comply with these targets, feed-in tariffs and other financial incentives can alternatively be modelled in order to assess which shares of renewable electricity production can be reached by a given amount of financial support. This support can be either capacity-related or production-related, i.e. it can be granted for the erection of renewable electricity generation capacities, like in the case of investment subsidies or tax cuts, or for the operation of renewable electricity generating installations, as in the case of fixed feed-in tariffs or premiums. Both generation-related and capacity related financial incentives are taken into account as benefits in the model, i.e. they are modelled as negative costs of fuel supply flows (see chapter 8.6.2). In the case of capacity-related incentives these are levelised on the expected production from the installed capacity.

7.3.3.3 Restrictions of possible renewable energy expansion rates

In order to fulfil a given renewable electricity target, but also when financial incentives are given, the least expensive potentials of a technology are always chosen to be fully utilised first as the economically most attractive option. When ambitious targets for renewable electricity generation are specified, also comparatively expensive renewable potentials have to be used for target compliance. As it is desirable from the model's cost-minimising perspective to reach target compliance with the cheapest available set of potentials and as late as possible, the solution will be to wait with the utilisation of the required amount of renewable electricity until the period for which the target compliance is stipulated, and then instantly install the required capacities. Given this fact, the cost minimising approach of the model will normally lead to a solution where the capacity additions favourable from a purely economic point of view exceed the technically possible expansion rates of the available potentials.

As a rule, such limitations of the possible expansion rates exist, e.g. due to permitting procedures, limitations of manufacturing capacities and possible growth rates of the respective industry branches. They can further be caused by grid expansions with the corresponding lead times, or other infrastructural limitations, as e.g. in construction and supply logistics[129]. While it is the governing principle of the model to identify the cost-optimised solution for the coverage of electricity supply, these restrictions for renewable energy potentials must be taken into account. In order to consider them in the model, the expansion of the potentials can be limited[130], both in terms of the minimum capacity that has to be installed, or the maximum total capacity that may be installed in a certain year. Further, also the rate of capacity increase, i.e. the possible capacity additions per year, can be limited.

Alternatively to, but also in addition to the above restriction of total capacities or capacity expansion rates, the annual expansion rate of the resource flows can be limited in order to introduce realistic boundaries for the possible spectrum of growth in the utilisation of renewable energy carriers by the introduction of time-dependent maximum growth rates.

7.3.3.4 Conditions for system reliability

Next to the load variation characteristics and the extraction of heat (see section 7.3.2.2.4), further restrictions inherent to the technical and physical properties of electricity systems have to be accounted for. These can be relevant either for individual technologies or for the power plant portfolio as a whole, as well as for the grid. In this context, sufficient capacity reserves for the coverage of the annual peak load as well as the provision of reserves for power plant failures and for ancillary services, as e.g. frequency stabilisation, is of essential importance[131].

Generally, two types of reserve requirements can be distinguished in a generation system. Firstly, in order to have sufficient capacity reserves installed for the time of maximum system load, it is necessary that the total amount of capacities installed is high enough to allow a reliable coverage of this extreme load, which only occurs on one or very few days of the year, most commonly in winter. Also the non-availabilities of fluctuating electricity generation, i.e. most importantly from wind power, must be sufficiently covered by this long term system reserve.

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[129] Especially for the development of offshore wind parks, specialised ships and equipment for transport and installation (e.g. jack-up barges) are necessary, which still have to be constructed in adequate numbers (see e.g. [Övermöhle et al. 2003, p. 81 ff.]. Furthermore, with an ongoing worldwide increase of transport by sea, the available port capacities for the storage and shipping of offshore wind turbine components can become limiting as well.

[130] Concerning capacity restrictions also compare section 7.3.2.2.3.

[131] A detailed analysis of the requirements for reserve capacities in large electricity grids requires comprehensive and complex models tailored especially to this task. Considering the aggregated scale of this analysis, such analysis features can only be partly integrated into the model described here. In this context it shall be ensured that the calculations and the results obtained by the PERSEUS-RES-E energy system model described here respect the most important results of the grid operation models. For a more detailed description of reserve capacity requirements in general and the interrelationship with growing amounts of fluctuating renewable electricity generation, reference is made to sections 4.3.1.1 and 4.4.1 as well as to [Dena 2005].

Secondly, it must also be ensured that at each time of the year sufficient reserves are available to cover the uncertainties resulting from possible power plant failures, as well as the forecast errors of the load. Moreover, when high wind power capacities are installed, the errors of wind power production forecasts need to be considered in addition. In the following it is described how both of these reserve considerations are included in the model.

7.3.3.4.1 Reserve capacity requirements

For the first reserve type, i.e. the requirement to the total system capacity to be installed in order to reliably cover the annual peak load, a straightforward way of modelling in energy system models is by assigning an availability factor $Avai_{unit,t}$ to energy conversion technologies. Specifying availability factors lower than one leads to a decrease of the available capacities of a certain technology for each time slot in the model. Thus, in order to cover a given load, and especially the annual peak load in the model, a higher total capacity must be installed. A drawback of this approach is that units can never be operated at their nominal capacity, even at times when the capacity of the unit is completely available. Consequently, other units in the model must be operated at a higher load, or additional units must be operated, which is not the case in reality. Depending on the power plant structure, this unrealistic dispatch can lead to errors in the determination of variable expenses and the expenses for fuels.

In order to avoid this drawback, an alternative way to guarantee sufficient reserve capacities is frequently chosen. In this case, a factor is specified, which determines the margin that the installed capacities in the energy system must lie above the maximum load. Equation (7.26) guarantees, that the installed capacity at any time exceeds the system load in a region reg by the factor $(1 + Reserve)$. The factor thus represents the installed capacities in the system that are unavailable due to unplanned outages, revisions, or the provision of ancillary services[132]. Further, renewable capacities with low availabilities, as e.g. solar or wind power units, can be excluded from the calculation of the total available capacity.

$$\frac{(1+Reserve)}{h_{seas}} \cdot \left(\sum_{proc \in DEMPROC_{reg,electr}} PL_{proc,seas,t} \cdot \Omega_{proc,t} \right) \leq \sum_{unit \in GENUNIT} \left(Cap_{unit,t} \cdot Avai_{unit,t} \right) + \sum_{unit \in WINDUNIT} Capsec_{unit,t} \quad (7.26)$$
$$\forall seas \in SEAS; \quad \forall t \in T; \quad \forall reg \in REG$$

However, for increasing installed capacities of technologies with fluctuating electricity production, their contribution to system reserves, i.e. their secured capacity or capacity credit, is not negligible any more. In the model, the capacity credit of wind power contributing to the coverage of reserve requirements is considered, while the

[132] The different categories of unavailable capacities can be estimated from system adequacy reports as e.g. [VDN 2003a], [TSOI 2004], [NORDEL 2003], [NORDEL 2005].

contribution of solar power is not included due to its expectedly continued low relevance throughout the modelled time horizon. For capacities with fluctuating electricity output, the capacity credit can be determined from the feed-in time series (see e.g. chapter 8.6.3.2 and [Dena 2005, p. 248]). While for Germany and Spain it is possible to determine the secured capacity from the AEOLIUS wind power input time series, for the other countries such detailed information is not available. Instead, the findings of the Dena study are generalised by making the conservative assumption that not more than 6% of the installed wind power capacities can be regarded as secured. Although a general transferability of the results from the German conditions to other countries is not necessarily given, the deviations caused by this generalisation can be expected to be small due to the generally low share of secured capacities in comparison to the overall installed capacities. In addition, the dependence of secured capacity on the required level of supply security is low for the usually required high security levels (>97%).[133]

7.3.3.4.2 Stipulation of sufficient tertiary reserve

In addition to the above approach ensuring system adequacy for the annual peak load, the following approach to represent reserve requirements in the model is realised in order to account for requirements to cover the uncertainties resulting from possible power plant failures, as well as the forecast errors of the load. With equation (7.27) it is ensured that sufficient tertiary reserve capacities are provided. While the principle of this approach can be applied to all qualities of reserves, i.e. primary, secondary and tertiary reserves, only tertiary reserves are accounted for in the model due to the restrictions of calculation times. Moreover, tertiary reserves are also most affected by fluctuating renewable electricity feed-in.

The overall level of required reserve capacities $Rdem_{(pr/sr)tr,reg,seas,t}$ in each region for each reserve type is determined using the current UCTE rules and system adequacy forecasts [UCPTE 1998], [UCTE 2004b], [VDN 2003b], [UCTE et al. 2001] and [Fingrid 2006], [Østergaard 2003], [NGC 2005]. The additional reserve requirements from wind power production $Rdem^{wind+}_{(pr/sr)tr,reg,seas,t}$ can be determined from [Dena 2005, p. 264 ff.].

$$\sum_{unit \in UNIT_{reg}} Rcap_{(pr/sr)tr,unit,seas,t} \geq Rdem_{(pr/sr)tr,reg,seas,t} + Rdem^{wind+}_{(pr/sr)tr,reg,seas,t} \qquad (7.27)$$
$$\forall seas \in SEAS; \quad \forall t \in T; \quad \forall reg \in REG$$

[133] Determining the secured capacity as the sum of the independently calculated secured capacities of the conventional capacities and that of the installed wind turbines implies a simplification. Actually, a recursive convolution analysis needs to be conducted for the conventional and renewable units in order to derive an exact value (compare e.g. [Dena 2005]). However, this type of analysis is only possible if individual units are modelled in a mixed-integer approach. Due to the resulting problem size and calculation times such an approach is not feasible in the case of PERSEUS-RES-E, where aggregated technology classes are used instead.

$Rcap_{(pr/sr)tr,unit,seas,t}$ denotes the power plant capacity that is effectively available for reserve purposes within the required maximum response times for the individual reserve types. It is always lower than or equal to the maximum capacity $Rcap^{\max}_{(pr/sr)tr,unit}$ that a unit can provide for reserve purposes (equation (7.28)). The latter value can e.g. be determined on the basis of load change gradients[134].

$$Rcap_{(pr/sr)tr,unit,seas,t} \leq Rcap^{\max}_{(pr/sr)tr,unit}$$
$$\forall seas \in SEAS; \quad \forall t \in T \tag{7.28}$$

Equation (7.29) prevents for each power plant, that the available capacity exceeds the sum of the capacities used for production and for all types of reserves ($Rcap_{tot,unit,seas,t}$: sum over all reserve types).

$$\sum_{proc \in PROC_{unit}} \left(PL_{proc,seas,t} \cdot \Omega_{proc,t}\right) + Rcap_{tot,unit,seas,t} \cdot h_{seas} \leq Cap_{unit,t} \cdot Avai_{unit,t} \cdot h_{seas}$$
$$\forall seas \in SEAS; \quad \forall t \in T; \quad \forall unit \in UNIT \tag{7.29}$$

7.3.4 Critical reflection of the chosen modelling approach

7.3.4.1 Underlying market concept and behaviour of market players

Compared to the situation in the real energy markets, which is characterised by different strategies of individual actors (profit maximisation, market power, etc.), the minimisation of the decision-relevant system expenditures, as stipulated in the objective function, represents a simplification, as all measures are assessed according to the same economic criteria. It is assumed that all market participants apply the same strategy, which consists of the common proceeding to cover the existing load with minimal expenditures. For this reason, the decisions made do not need to be the same as the decisions that would be optimal from the point of view of individual actors. Also strategic behaviour of single market participants, as e.g. the retention of capacities or price markups, is not considered in the approach described. While being a bottom-up model, its so called normative approach reflects a rather macroeconomic perspective on the evaluation of measures and allows to make statements on which actions should be taken from a sectoral perspective. This is what distinguishes the above approach from that of other electricity market models, such as system dynamics approaches or multi agent approaches. [Fichtner et al. 2003], [Genoese et al. 2005], present a concept for a multi agent approach and discuss the differences to an optimising approach together with a discussion of the advantages and disadvantages of both concepts.

[134] A load change rate of 8%/minute implies that e.g. a 600 MW unit can change its output by 48 MW within one minute.

However, for a long-term planning tool designed to understand evolution processes within energy supply systems, an optimising approach is quite useful. The modelling work in this case is focused on the correct representation of existing technologies, their parameterisation, and the modelling of technical, economic, and ecological restrictions, which limit the allowed solution space. With the underlying concept of perfect foresight, the marginal costs determined for electricity generation and CO_2 emission reduction can be interpreted as lower bounds for the future evolution of electricity and certificate prices.

7.3.4.2 Investment and disinvestment decisions in the model

A general problem related to the use of linear optimisation models is the occurrence of so called bang-bang effects. This term is used to characterise the fact that small variations of the input parameters can cause extreme changes of the model results. The underlying reason for this phenomenon is that out of two alternatives always the one leading to the lowest value of the objective function will be chosen. A typical example in optimising linear energy system models is a situation, where the power generation costs of two technologies in the same load range differ only marginally. In this case a slight variation e.g. of energy carrier prices can cause a change of total costs that inverts the relative advantage of the technologies, resulting in completely different investment decisions, although there is only a slight difference in the values of the objective function of both scenarios.

Thus, in an extreme case, this effect can lead to a power plant portfolio, which after the decommissioning of existing power plants is dominated by a single technology. Such a result is in contradiction to the intended application-oriented decision support. Usually, and among others due to the uncertainties related to the evolution of framework conditions, utilities will aspire a well balanced generation portfolio. The high investments related to the construction of power plants are an important reason for this behaviour. Investment decisions, which later prove to be wrong due to changed framework conditions inevitably cause high financial losses. Fuel price developments or energy policy measures which substantially differ from the developments anticipated in the planning phase can be examples for such critical changes of the framework conditions.

Various options exist to reduce the problems arising from bang-bang effects. Due to a detailed modelling of key technical characteristics, as e.g. load change capabilities, as well as through the specification of load profiles for different regions and energy carriers, only a limited number of relevant units compete in the resulting load ranges in PERSEUS-RES-E.

Moreover, in the case of politically motivated or other exogenously given limitations of a free optimisation, implausible results can be excluded by additional restrictions. Among others this is the case for the politically motivated phase-out of nuclear power generation, but also for constraints concerning the expansion of technologies with a limited possible total expansion, as e.g. for hydro power or other renewable energy carriers in general. However, it has to be taken into account that the solution space is further confined by such specifications.

Another option to limit the influence of bang-bang effects is to modify the methodological approach in order to account for uncertainties, i.e. using a stochastic programming approach. Such an approach has been realised e.g. by [Göbelt 2001]. However, problems related to an adequate quantification of the necessary parameters (expected values, standard deviations, risk preferences, etc.) can occur. Moreover, in order to model the branches of a decision tree, binary variables are necessary, which would lead to a significant increase of the model size and the necessary calculation times. Thus, instead of integrating stochastic influences directly into the model, an adequate variation of input parameters was realised in the framework of a scenario analysis.

The modelling alternatives described can support a technological diversification of model results in energy system analysis. However, it is not possible to avoid this general problem of linear optimisation completely, i.e. the fact that the results derived are strongly based on the individual alternatives. Thus, with a view on the results of the optimisations, it should be taken into account that they must be interpreted as general indications for the future development of the analysed energy system under the given framework conditions. Nevertheless, in a comparative analysis of the model results for different scenarios a robust strategy can be derived.

7.3.4.3 Price elasticity of electricity and heat demand

The driving force in the described modelling approach is the demand for electricity and heat. It is implicitly assumed that the demand reacts inelastically to changed prices, i.e. that there is no influence of price changes on the level of demand. It is argued that low or no price elasticities exist due to the fact that both heat and electricity can not be stored in larger quantities and can be substituted only to a very limited extent. While this has been empirically proven for short time horizons, in the long term a slightly negative price elasticity can be assumed (see e.g. [Dennerlein 1990], [Dahl et al. 1994] and [Wietschel et al. 1997a]). The reason is that rising prices over a longer time horizon can lead to energy efficiency measures being implemented in order to achieve a more efficient use of energy. In order to account for these dependencies it is possible to integrate energy saving measures or so called demand side management (DSM) options as well as price-dependent demand functions into the model approach (cf. [Wietschel 1995, p. 95 ff.], [Wietschel et al. 1997a], and [Rentz et al. 2006]).

While no price-dependent reactions of demand are directly accounted for in the developed modelling approach, the effects of a changed level of demand on the utilisation of conventional and renewable energy carriers can be assessed by the possibility to flexibly define alternative developments of demand levels in different scenarios.

7.3.4.4 Price information based on system marginal costs

Information on the future development of prices for electricity, CO_2 emission certificates and green certificates for renewable electricity can also be derived from the model output. This is accomplished based on the opportunity costs (system marginal costs) of the electricity demand that has to be met, and the imposed emission restrictions introduced, respectively. When making use of the price information it is necessary to have a closer look at system costs. With electricity price information derived as described above it should be carefully considered whether and how the change of the objective function value is correlated to the demand, which is specified for discrete time sections of each period during the time horizon of the optimisation.

Two cases can be differentiated and are desribed in the following. The first case comprises the vast majority of regarded time sections of the characteristic days that the load profile is based on. Exceptions occur only for the peak load segment, which shall be considered in more detail below. For covering an additional unit of load in this majority of time sections, there are always sufficient free capacities available remaining in the system. The price information derived for the opportunity costs is based on the short-term marginal costs of these available capacities.

In some of the peak load time segments, a different situation may be faced. An additional unit of load might possibly require further capacities, necessitating a new investment. This may lead to the occurrence of price peaks much higher than the peaks of the other time sections. Furthermore, investment decisions usually affect several time periods of the model. This means reservation might exist against a complete allocation of these costs to a single time section.

However, during situations of capacity shortage, extreme price peaks on the electricity market might not always be due to the costs of marginal power stations that occur by covering this load. Instead, peak prices can also result from the marginal profit of the last consumer. This marginal profit is determined by the costs of a possible load shedding and the resulting production losses, for example. Furthermore, at higher levels of scarcity speculative influences may become increasingly important. As a consequence of the normative perspective of the modelling approach, neither speculative influences on prices nor strategic actions are considered in the context of this work. System marginal costs can be used as economically plausible price information as long as the existence of perfect markets is assumed to be given. System marginal costs can be influenced by given restrictions like fuel supply limitations or the integration of a stock exchange.

8 Structure and data basis of the energy system model

In the following sections the assumptions and data employed for the long-term optimising energy system model are specified. This involves the representation of the electricity systems in the EU-15 Member States and those of relevant neighbouring regions in the model as well as the chosen model structure.

8.1 System boundaries and geographical scope

The countries represented by the model regions in the PERSEUS-RES-E model are depicted in Figure 32. Besides the EU-15 Member States also Switzerland and Norway as well as the four new EU Member States Poland, the Czech Republic, Slovakia, and Hungary are endogenously modelled. The geographical system boundaries beyond the EU-15 were chosen to cover regions that are relevant in terms of power production, power exchange, and CO_2 emission trading. In the model the above countries are represented by 25 regions, generally one region for each country.

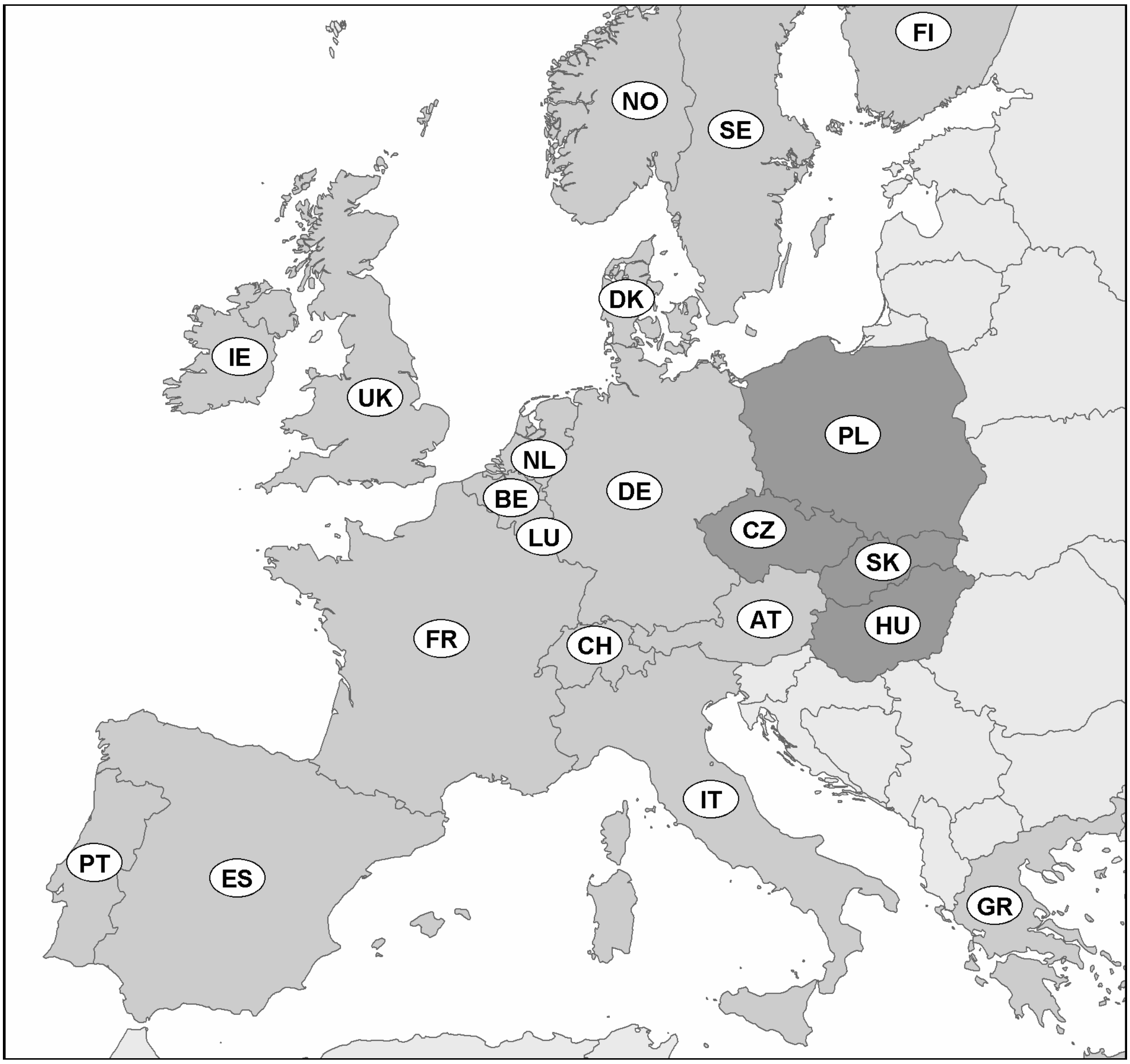

Figure 32: Geographical scope of the PERSEUS-RES-E model

As the only two exceptions, Denmark and Germany consist of several different regions. In the case of Denmark these are the two interconnected islands Funen and Jutland, and in the case of Germany the four regions coinciding with the former demarcation zones of the four grid operators. Import and export power flows based on historic power exchange data are considered as links to those countries adjoining to the endogenously modelled countries[135].

8.2 Time horizon and temporal resolution

For the long-term energy system optimisation with PERSEUS-RES-E a time horizon of 20 years from the base year 2000 until the year 2020 was chosen. With the choice of the base year 2000 a calibration of the model using statistical sources is possible. The end year 2020 coincides on the one hand with the upper limit for a reasonably accurate assessment of the available mid-term potentials of RES-E generation for the EU-15 (cf. chapter 3.4). On the other hand, the covered duration is long enough to assess the important restructuring developments that can be expected as a result of the large amount of capacities reaching the end of their lifetime in this period in combination with the economic and political framework conditions, such as emission resctrictions, the evolution of fuel-prices, etc.[136].

Due to restrictions concerning the available computing power (RAM) and acceptable computation times it is not possible to model this long time frame in a temporally highly resolved manner, e.g. each hour of the time horizon[137]. Instead, characteristic years are chosen to represent freely selectable periods of the modelled time horizon. In the developed model, equally long periods with a duration of five years are used. The load profile for each of these periods is represented by characteristic days. For a reasonably accurate modelling of the load profile, a total of 36 characteristic time intervals, or time slots, are distinguished for each characteristic year. As shown in Figure 33, these time slots cover the more volatile load profile of working days with a higher resolution (six time slots) than the less variable load profile on weekends (three time slots). Moreover, each season of a year (winter, spring, summer, autumn)

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[135] The PERSEUS-RES-E model and also the complementary simulation model AEOLIUS were developed in the framework of the project 'Large-scale integration of renewable energy carriers into the European electricity system'. The project was financed by the European Institute for Energy Research (EIfER) and carried out by a consortium of the Fraunhofer Institute for System and Innovation Research (ISI), the Bremer Energie Institut (b.e.i.), and the French-German Institute for Environmental Research (DFIU) at the University of Karlsruhe (see [Klobasa et al. 2004], [Pfaffenberger et al. 2005] and [Rentz et al. 2005b]).

[136] Beyond this time horizon the realisable renewable potentials, but also the technology options of conventional electricity generation along with their technical and economic properties are subject to high uncertainties. These uncertainties result from the strong dependence of the possible options on further technological developments and breakthroughs. However, within the chosen time horizon it is possible to assess the optimised adaptation of the electricity system to major structural changes like the end of life of significant conventional capacity shares and e.g. the nuclear phase-out.

[137] This limitation is the reason why fluctuating electricity production can not be adequately modelled in the same, long-term approach. Instead, the complementary simulation approach AEOLIUS has been developed and is coupled with the long-term model via a soft-link.

is represented by a different set of characteristic working days and weekend days, according to the variations in electricity consumption induced by changes of temperature and daylight hours throughout the year. Further, a restriction in the model code ensures the correct succession of time intervals which, among others, allows to determine the associated load change costs.

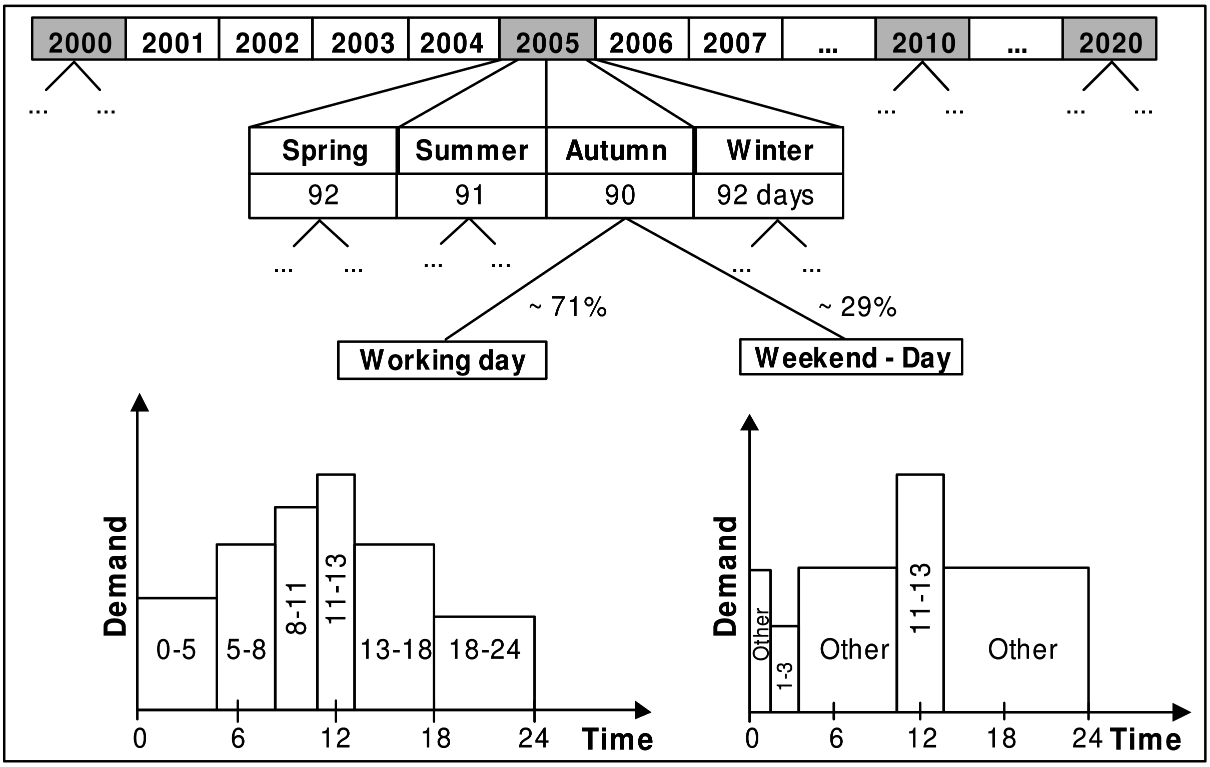

Figure 33: Temporal resolution of the modelled time horizon

8.3 Structure of model regions

All endogenously modelled countries, with the exception of Germany and Denmark, which each consist of several regions as described above, are composed according to the structure described in the following and depicted in Figure 34. Each of these model regions (designated as '*xxx')* is composed of five sectors, the fuel supply '*xxx-regional-fuelmarket*', renewable power generation '*xxx-renewables*', power and heat generation by public utilities '*xxx-utilitysupply*', industrial heat and power generation '*xxx-industrialsupply*', as well as the demand sector for power and heat '*xxx-demand*'.

Fuels from indigenous resources and those supplied from outside the region are differentiated by the use of the producers '*xxx-indigenous resources*', and the '*xxx-regionalfuelnode*'. From these two distribution nodes, the producers containing the energy conversion units within the sectors '*xxx-renewables*', '*xxx-utilitysupply*', and '*xxx-industrialsupply*' are provided with input energy carriers. Within these producers the input energy carriers are converted to the useful energy forms of electricity and heat. In the case of heat the pipeline transport, which due to losses is limited to shorter distances, is directed directly to the heat consumers[138], while the generated electricity is fed into a transmission grid node '*xxx-internalgridnode*'. From this grid node the different consumers are supplied with power. This includes the amount of power consumed by pumped storage power plants '*xxx-pumpedstorage*'. Furthermore, this node is connected to the interconnection lines with neighbouring regions. The parameterisation of these flows allows to model the existing interconnector capacities. Their utilisation is subject of the optimisation and determined by the cost differences between the two regions and the transmission losses.

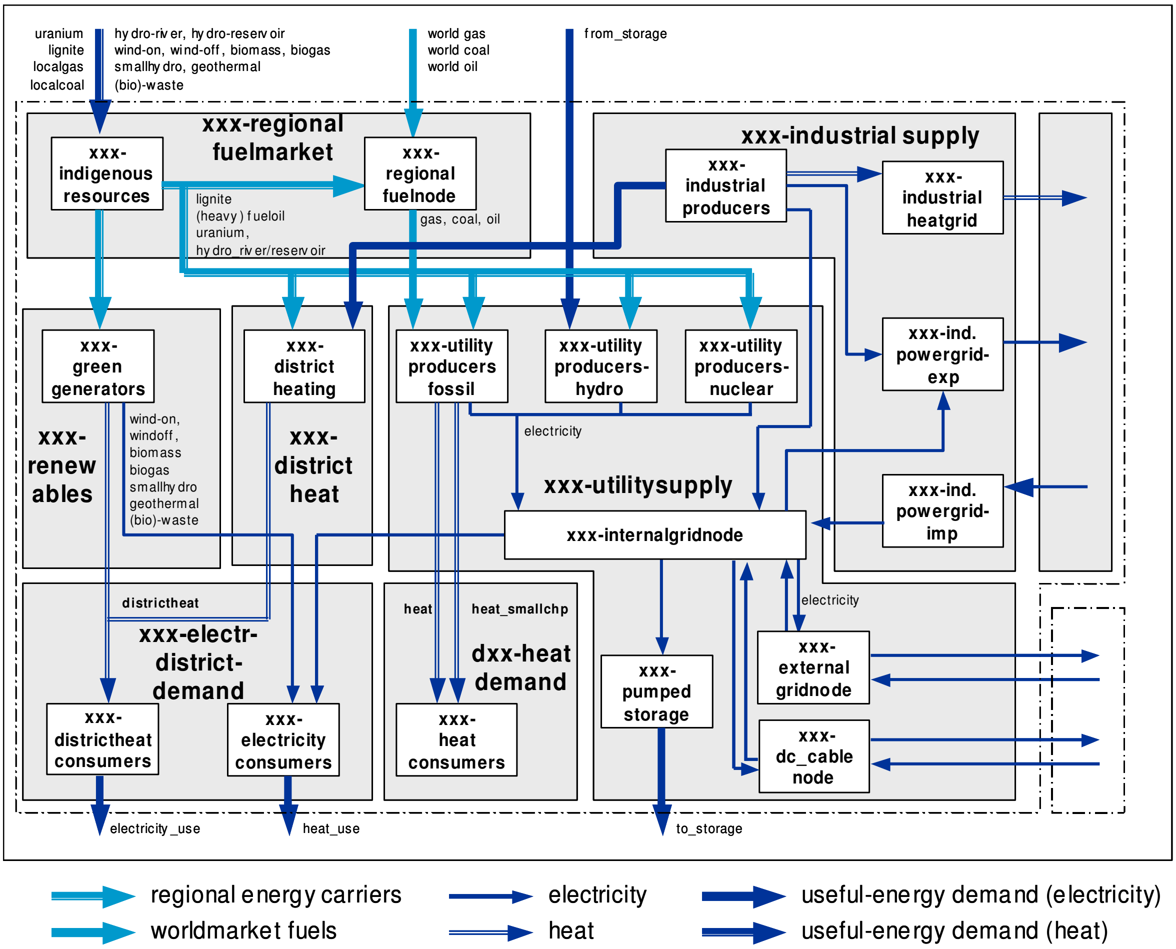

Figure 34: Structure of the endogenous model regions

8.4 Modelling and parameterisation of transmission grids

The existing physical limitation of power exchange through the interconnector capacities in the model, including the HVDC[139] sea cables, is realised by specifying a restriction of the maximum amount of energy that can be transmitted during each

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138 A differentiation is made between heat supplied by district heating plants for local heating networks and the heat provided by larger units to industrial consumers or long-distance heating networks. For both types of heat different demand profiles and trends for the future evolution of the demand are modelled.

139 **H**igh **V**oltage **D**irect **C**urrent.

time slot. Different from the capacities of the power production units, which are optimisation variables, the interconnector capacities in the model are exogenously given parameters and not part of the optimisation. The values used are based on UCTE online statistics[140], annual reports by NORDEL, and information on the NTC[141] values by [ETSO 2002].

From a modelling point of view it would be possible to include the possibility for a freely optimised extension of interconnector capacities. Additional nodes containing units of a certain, limited transmission capacity could be inserted into each interconnecting flow. Investments and fixed costs that would be necessary for an extension of these capacities would then have to be considered in the target function. However, this procedure is problematic for two reasons. Firstly, the extension or addition of interconnector capacities does not depend on purely economic reasoning, but also on political decisions. Further, the calculation of the necessary investments is not always straightforward, as the extension of the interconnector itself may necessitate the reinforcement of upstream or downstream parts of the grid. A more suitable way to examine grid extension options is thus by alternative scenario calculations.

Table 11: Electricity transmission losses (cf. [Enzensberger 2003, p. 94])

Region	Losses
A	6.0%
B	5.0%
CH	8.1%
CZ	20.0%
DE	4.3%
DM	4.0%

Region	Losses
DSW	4.0%
DW	4.0%
DKE	5.5%
DKW	5.5%
E	8.2%
F	7.0%
FIN	4.3%

Region	Losses
GB	7.4%
GR	9.0%
H	12.8%
I	6.5%
IRL	9.1%
LUX	2.0%
N	7.4%

Region	Losses
NI	9.1%
NL	4.1%
P	9.2%
PL	13.3%
S	7.8%
SK	7.9%

Apart from the installed capacity of the interconnectors the transmission losses associated with the interregional power exchange need to be taken into account. On the 380 kV voltage level of the UCTE grid the average losses amount to about 10% per 1000 km[142]. Transmission and distribution within each region are also subject to losses, with the major source of losses being the transformation of voltages between the different voltage levels. National electricity balances, e.g. in [Eurostat 2004] or [UNIPEDE 1999], can be used to determine these values for each country. The

[140] Available on www.ucte.org. In addition, the foreseeable additions and reinforcements of transmission lines to be realised are taken into account in the model.

[141] Net Transfer Capacities. The NTC value is determined from the Total Transmission Capacity (TTC) minus a safety margin called Transport Reliability Margin (TRM).

[142] Average values in the same order of magnitude are also used in other studies (cf. e.g. [Pfaffenberger et al. 1990], [Hoster 1996]). The losses are dependent on a number of factors as e.g. the actual amount of power transmitted and the ambient temperature, reaching up to 25% under full load [Oeding et al. 2004, p. 311].

values used for the base year are summarised in Table 11, expressed as a percentage of the sum of the domestic electricity generation and the regional electricity exchange balance.

Next to the above physical parameterisation, the power exchange options between model regions are also economically characterised by transmission fees. While up to 2003 cross-border transits of electricity were characterised by inhomogenous tariffs [ETSO 2003a], the existing tariffs were reduced and homogenised by the introduction of a system of quantity-based entry-exit charges [ETSO 2003b][143]. Thus, from the year 2003 onwards, a uniform charge of 0.05 cent/kWh is implemented in the model, while the formerly existing tariff structures are represented by higher charges up to 0.15 cent/kWh in the base year 2000[144].

8.5 Conventional electricity generation

In the following, all aspects of the parameterisation of conventional electricity generation will be introduced, including the fuel supply as well as the economic and operational characteristics of different conversion technologies.

8.5.1 Fuel supply options and fuel prices

Due to the fact that fuel costs represent a considerable share of power production costs, the determination of suitable assumptions for the development of energy carrier prices is a key challenge especially for long-term strategic analyses of the power sector. Forecasts for world market developments and price projections are published in regular intervals by a number of institutions, such as the European Commission, the International Energy Agency (IEA), the OECD, or the United States Department of Energy (DOE). Although based on an extensive amount of data, these forecasts can differ substantially from each other as well as from one volume to the next[145].

Table 12: Worldmarket price trends for fossil energy carriers (cf. [Enzensberger 2003, p. 100])

World market price [$cent_{2000}/kWh_{therm}$]		(2000) Data	2005	2010	2015	2020
Fuel oil	Reference trend	(1.73)	1.32	1.32	1.42	1.53
Natural gas	Reference trend	(1.11)	1.10	1.12	1.21	1.31
Coal (worldmarket)	Reference trend	(0.42)	0.47	0.47	0.48	0.49

143 Electricity fed into the interregional transmission grid is charged according to the amount of energy, and - different from the incurred transmission losses - is not related to the transport distance.

144 See [Enzensberger 2003, p.95].

145 [Enzensberger 2003] deals with these differences by deriving a price band for each technology.

For the energy carriers coal, natural gas, and fuel oil the price developments used in the model calculations are shown in Table 12. To account for the growing importance of natural gas for power production and the uncertainties involved in the development of oil and gas prices[146], this parameter can be varied in a scenario analysis to identify the sensitivity of model results over the possible price range.

Both the taxation of energy carriers and transporting the fuels to the point of use in the respective power stations cause an additional fuel cost component, which is accounted for based on the location of the power plants[147]. The values in the model differ from 0.0 - 0.2 cent/kWh_{therm} for hardcoal, with the lower value applying to Poland and the higher one for Austria and Switzerland, respectively. For natural gas, the range is between 0.0 cent/kWh_{therm}, as e.g. for the Netherlands, up to 0.3 cent/kWh_{therm}, as e.g. for Italy.

For nuclear power plants the future fuel costs will depend on the developments on the market for uranium. Reliable price forecasts for this market are difficult due to political influences and limited competition, which complicates the free formation of prices (cf. [IEA 2001, p. 149]). According to [IEA 2001, p. 148] a practically constant development is assumed for the uranium price in the model. Including the costs for the supply and disposal of fuel elements it is set to 0.40 cent/kWh_{therm} for the model-based analysis in this work[148].

Similar to nuclear power plants, lignite power plants supply base load electricity at low variable costs. But contrary to nuclear power generation, lignite power plants have very high specific CO_2 emissions. Due to the higher water and ash content of lignite in comparison to hard coal, it can not be economically transported over longer distances. Thus, lignite power plants are built in the immediate vicinity of the mines. No price statistics exist for lignite (cf. [Prognos 2000, p. 203]] as it is not traded on a market, but is either used in company-owned power plants or by customers with long-term contracts. In the model calculations, data established by [Enzensberger 2003, p. 102] from press reports and expert opinions is used, which in the case of Germany varies between 0.38 cent/kWh_{therm} and 0.46 cent/kWh_{therm}.

8.5.2 Technology data

Technology classes are used to represent the power plant portfolios of the modelled European regions. Within each technology class the total installed capacity of a group of technically and economically comparable units and their individual

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146 The demand for natural gas is increasing also in other branches of the energy industry. In the transport sector, it may also be used either as a direct substitute for oil or in the longer term as a feedstock for hydrogen generation (compare e.g. [Ball 2006]). [Perlwitz et al. 2005] use an energy system model for the endogenous analysis of the interdependencies between the gas market (demand, resources, reserves, transport capacities) and the European electricity market.

147 Estimations of this price component, which are used in the described model, have been carried out by [Grobbel 1999] and [Enzensberger 2003] for the different European countries.

148 The effects of alternative price developments, e.g. due to higher costs for the disposal of nuclear wastes, can be analysed in different scenarios.

processes is represented, all of which can be described by an identical set of characteristic parameters. All units are assigned to a technology class based on the following criteria: the units' location, i.e. the model region, the type(s) of energy carrier(s) used, the applied conversion technology, and the range of the capacities of the units. This proceeding allows to reduce the absolute number of modelled conversion units and thus serves as a means to confine the model size and the resulting calculation time to an acceptable level. Each of the units is described by a set of parameters as listed in Table 13.

Table 13: Techno-economic parameterisation of the modelled power production units

<table>
<tr><th rowspan="2"></th><th rowspan="2" colspan="2">Technical data</th><th colspan="2">Economic data</th><th rowspan="2">Ecological data</th></tr>
<tr><th>Parameters</th><th>Restrictions</th></tr>
<tr><td rowspan="3">Unit</td><td colspan="2">Installed capacity</td><td>Investments</td><td rowspan="2">Restriction of free (de-) commissioning</td><td rowspan="3"></td></tr>
<tr><td colspan="2">Availability</td><td>Fixed expenditures</td></tr>
<tr><td colspan="2">Technical lifetime</td><td>Economic lifetime</td><td>Predetermined commissioning</td></tr>
<tr><td rowspan="7">Process</td><td>Input 1</td><td rowspan="3">Respective share of total input</td><td rowspan="3">Other variable costs (excl. fuel)</td><td rowspan="3">Restriction to Baseload operation</td><td rowspan="7">Emission factors (specific CO_2 emissions)</td></tr>
<tr><td>Input 2</td></tr>
<tr><td>Input 3</td></tr>
<tr><td>Output 1</td><td rowspan="3">Respective share of total output</td><td rowspan="4">Load change costs</td><td rowspan="3">Fixed output share of operating mode(s)</td></tr>
<tr><td>Output 2</td></tr>
<tr><td>Output 3</td></tr>
<tr><td colspan="2">Efficiency</td><td>Full-load hours</td></tr>
</table>

The parameterisation of the existing conventional power plant capacities in the model as well as the age structure of the individual technology classes in the different model regions is mainly based on data from [Eurostat 2002], [Enzensberger 2003] and [UCTE 2004c]. Moreover, model regions were cross-checked with national statistics and amended or corrected where necessary. The decommissioning of existing capacities constructed in past years is administered by the help of a vintage approach. This means that the existing power plant types have been grouped according to technology classes, each of which was installed in a given past time period. Each of these technology classes is modelled with a maximum technical lifetime, after which this power plant type is assumed to reach the end of its lifetime and needs to be replaced. The structure of the modelled technology classes is mainly based on [Klatt et al. 1999], [Meller et al. 2002], [UCTE 2000a] and [UNIPEDE 2001]. The remaining technical and economic data in the model originate from an energy sector data base maintained at the Institute for Industrial Production (IIP), which contains generic data of energy conversion technologies. Originally based on [IEA 1998b] and [GEMIS 2002] this database has been continuously amended and updated based on a number of technical publications as well as interviews and estimations by industry experts.

8.5.3 Expansion options

Furthermore, the model contains all relevant technology options for future capacity additions, as summarised in Table 14.

Table 14: Conventional expansion options (source: IIP technology data base)

Technology	Year	Block size [$MW_{install}$]	Net efficiency [%]	Specific investment [€/$kW_{install}$]	Fixed costs [€/(kW*a)]	Additional variable costs[149] [cent/kWh_{el}]
Natural gas						
Combined cycle (small)	2005	300	58.5	410	14	0.05
	2010		59.5	405		0.05
	2020		59.5	405		0.05
Combined cycle (large)	2005	800	59	400	14	0.05
	2010		60	395		0.05
	2020		60	395		0.05
Gas turbine (peak load)	2005	150	35	260	6	0.15
	2010		36	260		0.15
	2020		37	260		0.15
Hard coal						
Pulverized, subcritical steam generator	2005	700	42.5	750	36	0.15
	2010		43	750		0.15
	2020		43	750		0.15
Pulverized, supercritical steam generator	2005	700	46	825	36	0.15
	2010		46.5	825		0.15
	2020		46.5	825		0.15
Lignite						
Pulverized, subcritical steam generator	2005	900	40.5	900	38.5	0.2
	2010		41	900		0.2
	2020		41	900		0.2
Pulverized, supercritical steam generator	2005	900	43.5	1000	38.5	0.2
	2010		45	950		0.2
	2020		45	950		0.2
Nuclear						
Boiling water reactor	2005	1000	33.5	1275	42.5	0.05
	2010		34	1275		0.05
	2020		34.5	1275		0.05
European pressurized water reactor (EPR)	2005	1700	35.5	1250	42	0.05
	2010		36	1250		0.05
	2020		36	1250		0.05

[149] Excluding fuel costs, these are accounted for in the cost parameterisation of energy carrier flows.

In order to account for likely technological improvements, the units available in later periods are partly attributed lower investments and cost components, and also higher efficiencies where these are expected.

Along with hydrogen-based power generation technologies, technologies for CO_2 capture and storage (cf. e.g. [COORETEC 2003]) from conventional fossil power plants have not been regarded as expansion options within the modelled time horizon. Their realisation on a large scale, preferentially in combination with coal-based IGCC (Integrated Gasification Combined Cycle) processes, is not expected to take place before 2020 (cf. e.g. [Ewers et al. 2005]). Instead, it is assumed that up to then technological progress in terms of fuel efficiency and CO_2 mitigation is most economically achieved by more advanced conventional combustion processes without a gasification stage.

8.6 Renewable electricity generation

In the following, the methodological and data-related aspects of the parameterisation of renewable electricity generation will be introduced. This includes the fuel supply, as well as the economic and operational characteristics of different renewable energy conversion technologies. The following renewable energy carriers with their potentials and costs for electricity production are included in the model database and later on in the analysis of the model-based market penetration scenarios:

- biodegradable fraction of municipal solid waste (MSW);
- biogas (fermentation);
- conventional geothermal electricity production;
- HFR/HDR[150] geothermal electricity production;
- hydro power small scale (< 10 MW);
- hydro power large scale (> 10 MW);
- landfill gas;
- sewage gas;
- solar photovoltaics;
- solar thermal electricity;
- solid biomass (wood, energy crops, agricultural residues);
- tidal energy;
- wave energy;
- wind energy onshore ;
- wind energy offshore.

[150] **H**ot **D**ry **R**ock / **H**ot **F**ractured **R**ock

8.6.1 Resources and costs of renewable electricity generation

In order to determine the possible future penetration of renewable energy resources for electricity production, their realisable potential first needs to be known.

As the major basis for a sufficiently detailed representation of renewable energies in the PERSEUS-RES-E model the results of a comprehensive assessment of renewable sources of electricity in the EU-15 by [Klobasa et al. 2004] are used. The mid-term potentials as well as the costs for the utilisation of these potentials in each Member State were assessed for a total of 15 renewable energy sources (cf. chapter 3.4). Thus, a coherent classification and comparable figures for the energy systems of the modelled countries are available as input data to the model. Using this comprehensive data basis allows a sophisticated evaluation of different options and possibilities of an integration of renewable energy carriers in the modelled regions.

The characteristics of the methodology used to derive updated potential and cost data[151] can briefly be characterised as follows[152]:

In most cases a 'top-down' approach is used, e.g. for wind energy and photovoltaics. This means that the mid-term potential has been derived starting with the consideration of the total available energy flow of the energy carrier. Based on this upper limit, the realisable mid-term potential can be determined step by step, by taking into consideration the existing barriers or limitations, such as the technical feasibility, social acceptance, planning aspects, and the possible growth rate of the industry. For other renewable energy technologies, a 'bottom-up' approach has been more successful, such as e.g. for geothermal electricity. Such a bottom-up assessment is carried out by looking at every single site where energy conversion appears to be possible, deriving the cumulative potential based on the individual assessments.

A summary of the realisable mid-term potentials for annual electricity production up to the year 2020 by country and by energy carrier is given in Figure 35 and Figure 36[153]. The overall potential in all EU-15 Member States amounts to about 1,546 TWh/a realisable electricity production in 2020. In absolute terms, the largest potentials are located in Germany and France. When related to electricity consumption, the largest potential shares of renewable energy sources can be found in Ireland and Austria. In both countries the available renewable electricity potentials are large enough to supply between about 15% (Austria) up to about 37% (Ireland) more electricity than is currently demanded.

[151] In the ElGreen report, this potential is called the 'mid-term potential'.

[152] The underlying assessment is based on the methodology that has been used in the ElGreen project [Haas et al. 2001b], and later in a refined version also for the Green-X project [Huber et al. 2004].

[153] In addition to the potentials shown in the figures the potentials for geothermal electricity generation from Hot Dry Rock and Hot Fractured Rock installations in Germany as determined by [Paschen et al. 2003] have been considered. While the size of these potentials (about 290 TWh/a) is of great significance, technological barriers have to be overcome to actually realise them (cf. chapter 9.3.6).

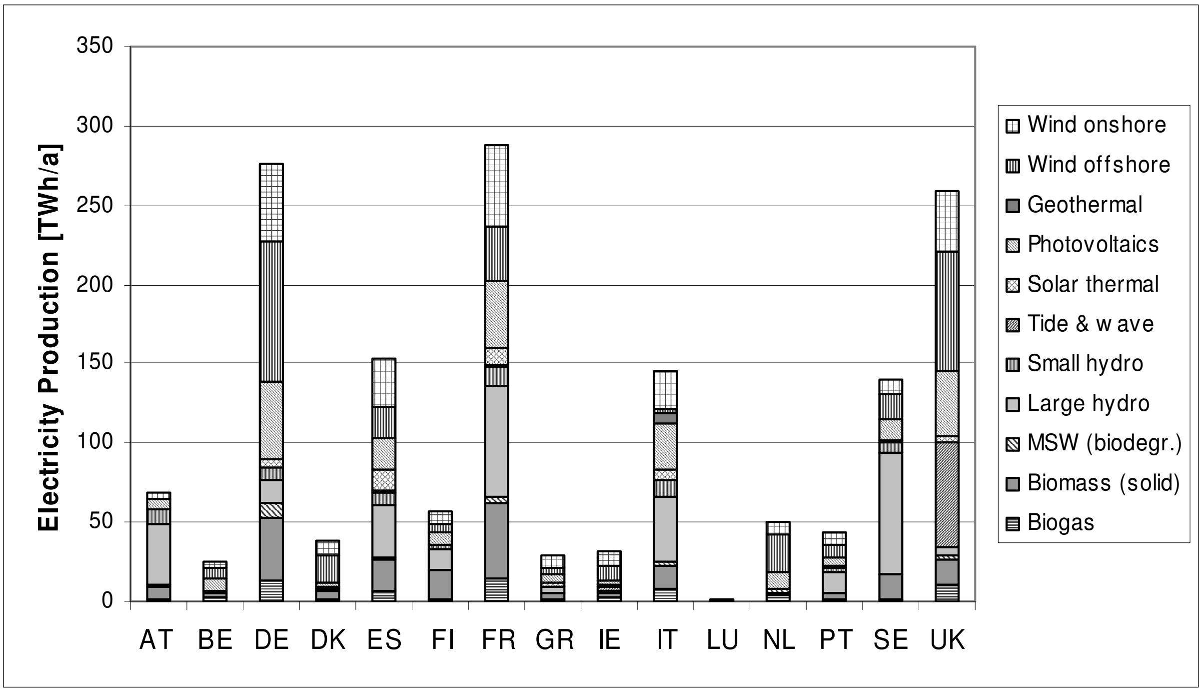

Figure 35: Renewable electricity potentials in the EU-15 by country (based on data from [Klobasa et al. 2004])

For the individual categories of technically available renewable energy carrier potentials static cost-resource curves are used to describe the relationship between the size of each potential and the costs for its utilisation at a given point in time. These curves need to distinguish between existing installations already in operation and those potentially to be installed in future periods. While for existing units the costs are represented by short-term marginal costs, for new plants the long-term marginal costs, i.e. full costs, are relevant[154].

In order to have consistent information on all renewable electricity technologies in the EU-15 Member States already realised until the end of 2002, the base year for the potential analyis, the values for renewable electricity generation by source and by country were taken from the annual Eurostat energy statistics [Eurostat 2004], for the years 2000 until 2002. Additional information on renewable electricity use was derived from [IEA 2004b].

The realisable additional mid-term potentials used for each renewable energy source in the model-based approach indicate the maximum potential that is additionally achievable for the time horizon up to the year 2020, assuming that all existing barriers can be overcome and all driving forces are active, i.e. with no dynamic delay of the realisation of the potentials (cf. chapter 3.4.1).

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[154] Complementarily, dynamic cost-resource curves are characterised by the possibility that the costs as well as the available potential for electricity generation can change from one year to another, with the difference in the values compared to the previous year depending on the realised new installatios of the previous year as well as the possibly changed economic and political framework conditions for the current year.

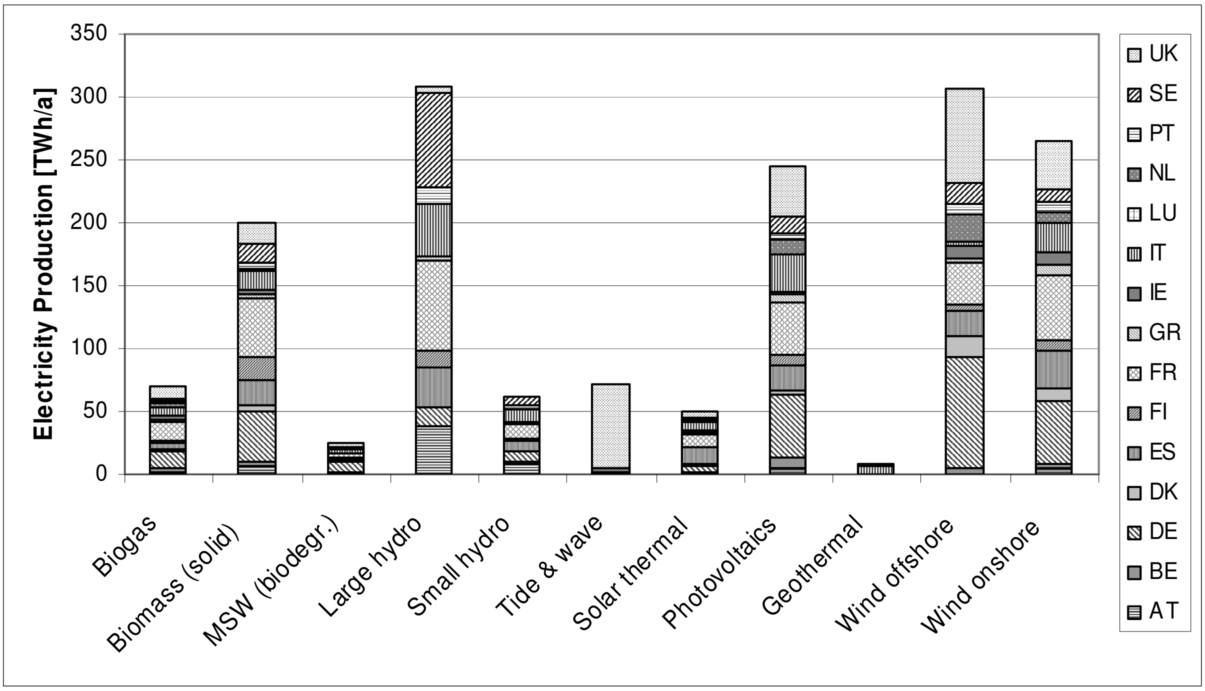

Figure 36: Renewable electricity potentials in the EU-15 by energy carrier (based on data from [Klobasa et al. 2004])

Taking into account the fact that RES-E installations at different locations are slightly different from each other, the resulting theoretical cost-potential curve, which sorts all potentials in a least cost order, comparable to a merit order curve, is continuous. For the practical use in a linear long-term optimisation model these curves must be linearised. By grouping sites with similar characteristics (e.g. wind power sites with a similar range of full-load hours and the same investment and operating costs) to a technology band, a stair function results. The basic principle of these renewable electricity supply curves is thus that each convex supply curve is partitioned into n production contingents, which each are available at a price p_n. This is illustrated in Figure 37 for several renewable energy carriers in France.

Compared to previous PERSEUS models and comparable linear modelling approaches, where renewable electricity is modelled either as a predetermined expansion path or as comparatively coarse cost-resource curves, PERSEUS-RES-E features a very detailed representation of renewable sources with regard to the number of individual potentials and their costs in each modelled region. At the chosen level of aggregation the model takes into account an average of about 100 different potentials of renewable electricity sources in each EU-15 Member State, along with the corresponding technical and economic data. Due to the linear nature of the PERSEUS modelling approach, each step of the cost-potential curves is modelled as a separate expansion option, in addition to the already existing capacities. Within the model structure, each of these expansion options is created as an optional unit in the producer *xxx-renewables*, which exists in each modelled region. Each of the units contains a process, which is characterised by the parameters typical for the energy carrier used.

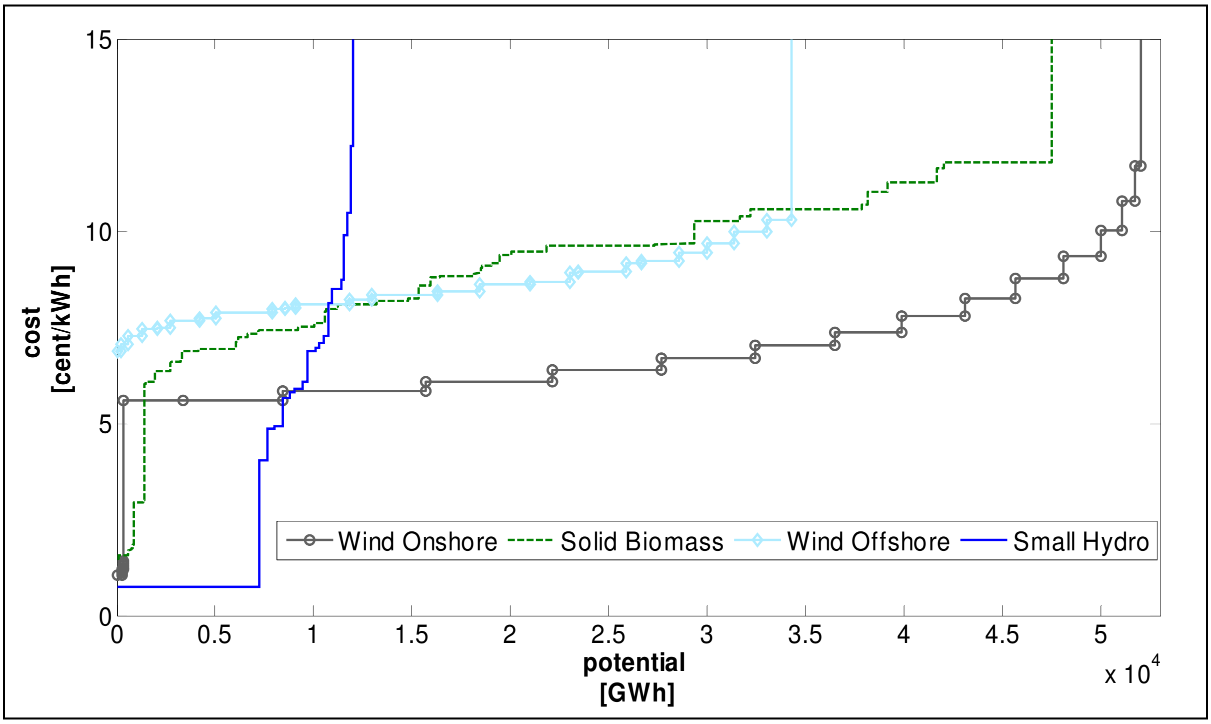

Figure 37: Exemplary cost-potential curves in France (based on data from [Klobasa et al. 2004])

The potentials of the majority of renewable energy technologies in the model are characterised by technology-specific average full-load hours and by specific variable costs for each potential. In order to take into account investments and fixed costs, these are levelised over the full-load hours during the expected lifetime of the installations and included as a component of the specific variable costs, i.e. the variable costs taken into account represent the long-run marginal costs (full costs) of each potential. Thus, the RES-E technologies' potentials in the model are typically represented by the following parameters:

- technology-specific average full-load hours [h/a];
- maximum realisable capacity of the potential [MW];
- efficiency [%];
- long-run marginal costs (specific variable costs plus investments and fixed costs levelised on technology specific full-load hours [cent/kWh][155]);
- economic lifetime [a];
- technical lifetime [a].

For the wind energy potentials more differentiated values have been integrated:

- full-load hours for each potential [h/a];
- specific investment [€/kW];

[155] Including levelised investments and fixed costs distributed over the economic lifetime of a typical plant.

- specific fixed costs [€/kW];
- specific variable costs [cent/kWh][156].

This is owing to the fact that the electricity yield and the costs for the exploitation of wind energy potentials are very dependent on the location and on the type of wind turbine used. The wind energy potentials in each country are thus differentiated by the value of the achievable full load hours and wind turbine size. As for the modelled conventional technologies, different cost components are considered, including specific investments and fixed costs for different wind turbine types, as well as variable costs for operation and maintenance.

The following table gives an example for the parameters taken into account to characterise an economically favourable portion of the French onshore wind resources, which is characterised by an average of 2,050 full-load hours per year.

Table 15: Exemplary characterisation of a portion of the French onshore wind potential (characterised by the turbine type and full load hours)

f-pot-wind_on_2	Unit	Value
Typical turbine size	[kW]	1,500
Specific investment	[€/kW]	1,050
Total investment	[million €]	1.575
Operation & maintenance costs	[€/kW]	36.75
Variable costs	[cent/kWh]	1.14
Full-load hours	[h/a]	2050
Efficiency	[-]	1
Electricity generation	[MWh/a]	3,075
Economic lifetime	[a]	20
Technical lifetime	[a]	20
Total size of unrealised potential	[GWh]	310

The availability of potentials is limited by a maximum capacity defined for each unit, resulting from a division of the given potential (GWh) by the appropriate value for the annual time of operation (full load hours).

In order to achieve more flexibility concerning the model size and level of detail an aggregation of the detailed potential and cost data can be applied, most favourably to the less significant potentials. An MS Excel software tool has been developed, which is used for a selective aggregation of the potentials and corresponding cost data of the 15 renewable energy technologies in each country of the EU-15. Since the algorithm for this aggregation is flexible regarding the size and number of aggregation intervals, it is ensured that the characteristic features of the cost-potential curves are represented for each energy source in all of the EU-15 countries,

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[156] Excluding levelised investments.

for which the potentials have been assessed. While large potentials as well as those with a very broad cost spectrum are represented in greater detail, smaller and thus less significant potentials may be represented in an aggregated way in order to increase computation efficiency. For similar reasons, a trade-off between the level of detail in modelling the renewable electricity sources and the geographical scope of the model is reasonable.

8.6.2 Financial incentives for renewable electricity generation

Next to the purely cost-based assessment of the utilisation of renewable energy sources all over the EU-15, the model-based analysis can also be used to assess the effectiveness of the currently existing variety of different national financial incentives.

As a data basis, the EU Commission staff working document COM(2004)366 [EC 2004b] was used. Beginning with the year 2003, i.e. the first year after the base year for the determination of the mid-term RES-E potentials, the incentives are introduced into the model. For reasons of comparability and due to the often unknown future development of the height of the incentives, their levels were left as indicated in the above document throughout the modelled time horizon. As the only exception, the degression prescribed in the German feed-in law was implemented[157]for the German tariffs, which are significantly higher than in other countries for a number of RES-E sources. In order to account for construction lead times and technological or logistical barriers, especially for less proven technologies like offshore wind or geothermal power production, the possible absolute utilisation as well as the exploitation rate of potentials are restricted (cf. capacity and flow limitations described in section 7.3.3.3). Generally, the incentives are modelled as negative specific costs on the flows of the renewable energy carriers, i.e. the incentives are subtracted from the total costs of the utilisation of the potentials, reducing the RES-E power production costs. As described above, the latter are given by the investments, fixed, and variable costs in the case of wind energy and for all other potentials expressed as a single variable cost component. Generation-based incentives like fixed feed-in tariffs and premiums are taken into account as well as capacity-based incentives like investment subsidies and tax cuts, which are levelised on the energy yield of the installations. In the cases where different tariffs are applicable, e.g. depending on the capacities of installations, an average value was chosen for the representation in the model. Table 16 gives an overview of the different incentives taken into account in the PERSEUS-RES-E model.

No cost savings have been assigned to the use of RES-E technologies quota-based schemes. Instead, as the most appropriate representation of a successful quota system, the fulfilment of the 2010 targets is required by a constraint in the model in these countries. Thus, in the sense of the green certificate scheme design, the cheapest potentials are used to reach the given quota. However, this idealised

[157] Between 1% and 5%, depending on the RES-E source [EEG 2004].

assumption does not take into account the case that penalties or buy-out fees can be paid for non-compliance, which eventually could result in non-compliance with the RES-E targets in those countries. Also, capacities can be installed, but not operated e.g. under a tendering scheme or when investment support is granted.

Table 16: Financial incentives for renewable electricity used in PERSEUS-RES-E (based on [EC 2004b])

	Financial incentives [cent/kWh]														
	AT	BE	DK	FI[158]	FR[159]	DE[160]	GR[161]	IE[162]	IT[163]	LU[164]	NL[165]	PT[166]	ES[167]	SE[168]	UK[169]
Small hydro	4.7	---	---	4.2	6.75	7.15	7.4	---	---	2.5	8.95	7.2	6.49	---	---
Solarthermal	---	---	---	---	---	59	7.4	---	---	---	---	---	12	---	---
Photovoltaics	53.5	---	---	---	15	59	7.4	---	---	50	8.95	41.0	39.6	---	---
Wind onshore	7.8	---	4.8 [170]	6.9	6.13	8	7.4	---	---	2.5	7.0	4.3 – 8.3[171]	6.21	---	---
Wind offshore	---	---		6.9	6.13	8.5	7.4	---	---	---	8.95		6.21	---	---
Geothermal	7.0	---	---	---	7.75	11.3	7.4	---	---	---	---	---	6.49	---	---
Biomass	13.1	---	5	4.2	5.45	9.0	7.4	---	---	2.5	7.6	6.2	6.85	---	---
Biowaste	9.7	---	1	4.2	3.75	9.0	7.4	---	---	2.5	2.9	6.2	6.05	---	---
Biogas	13.4	---	4	4.2		9.0	7.4	---	---	2.5	2.9	6.2	6.05	---	---
Sewage gas	4.5	---	4	4.2	5.75	7.15	7.4	---	---	2.5	2.9	6.2	6.05	---	---
Landfill gas	4.5	---	4	4.2	5.75	7.15	7.4	---	---	2.5	2.9	6.2	6.05	---	---
Tidal, Wave	---	---	---	---	---	---	7.4	---	---	---	8.95	22.5	6.49	---	---

8.6.3 Fluctuating renewable electricity generation

8.6.3.1 Hydropower feed-in

Relevant parameters influencing the available run-of-river hydro power production and the inflow to storage reservoirs are the annual precipitation characteristics as

158 Plus investment subsidy: wind 30%; others 40%.
159 For installations up to 12 MW, guaranteed for 15 or 20 years, rates are adjusted for inflation.
160 2002
161 7.8 cent/kWh on the islands and 7.0 cents/kWh on the mainland; Investment subsidies of 30%.
162 Tendering system.
163 Green certificate system with mandatory quotas.
164 Investment subsidies of up to 40%.
165 2004
166 2003
167 2003
168 Green certificates, aim is 17% renewable electricity by 2010; intermediate regulations until 2007.
169 Green certificate system with mandatory demand, grants for renewable energy installations, exemption from Climate Change Levy.
170 For new installations.
171 <2600 h: 4.3 cent/kWh; 2400 – 2600 h: 5.1 cent/kWh; 2200 – 2400 h: 6.0 cent/kWh; 2000 – 2200 h: 7.0 cent/kWh; <2000h: 8.3 cent/kWh

well as the snow melting process in mountaineous regions. The resulting annual energy yield is subject to variations, which in Germany are around 20% [Quaschning 2000]. In arid regions, as e.g. in Spain, larger variations of more than 50% can occur (see [IEA 2004b], [Eurostat 2005]). The comparatively slow and well predictable seasonal variations of hydro power production are taken into account in PERSEUS-RES-E as seasonally differentiated production coefficients. These production coefficients are determined from the average power output during a specific season of the year, which is related to the average power output during the whole year[172].

8.6.3.2 Wind power feed-in

When taking into account the fluctuation-induced effects of randomly available renewable electricity generation technologies like wind energy in a long-term, optimising power system model like PERSEUS-RES-E, three relevant aspects need to be distinguished:

- secured capacities of wind turbines (the so-called capacity credit);
- additional reserve capacity requirements; and
- efficiency losses induced in the operation of conventional power plants.

To model the effects in PERSEUS, the following procedure has been chosen:

Firstly, the **secured capacity** of wind power plants can be derived from statistical analyses, as e.g. in [Dena 2005] for the German wind power sector. Comparably profound figures are not yet available for other countries with high wind energy growth rates. For Germany and Spain the figures for the secured capacity of wind power can also be derived directly from the wind power time series used in the AEOLIUS model (cf. Figure 38 for Germany). The introduction of offshore wind power capacities from 2010 onwards, which show higher availabilities and full-load hours than onshore turbines, can be perceived in the rising available capacities throughout the range of probabilities. However, in the range of the highly reliable availabilities (97% probability and above), which are the basis for the determination of secured capacity, the difference is comparatively small.

The secured capacity value is added to the secured capacity of conventional power plants in the PERSEUS-RES-E calculations (see chapter 7.3.3.4.1). The secured capacity depends on the geographical distribution of the wind parks, i.e. the overall share of different types of onshore and offshore wind parks installed, and the required level of the security of supply[173].

[172] In a more detailed modelling approach for Swiss hydro power by [Möst 2006] monthly differentiated values, the so called Pardé coefficients, are used.

[173] A required security of supply of e.g. 97% implies that only that amount of wind turbine capacity can be counted as secured capacity, which is available in more than 97% of the hours of a year.

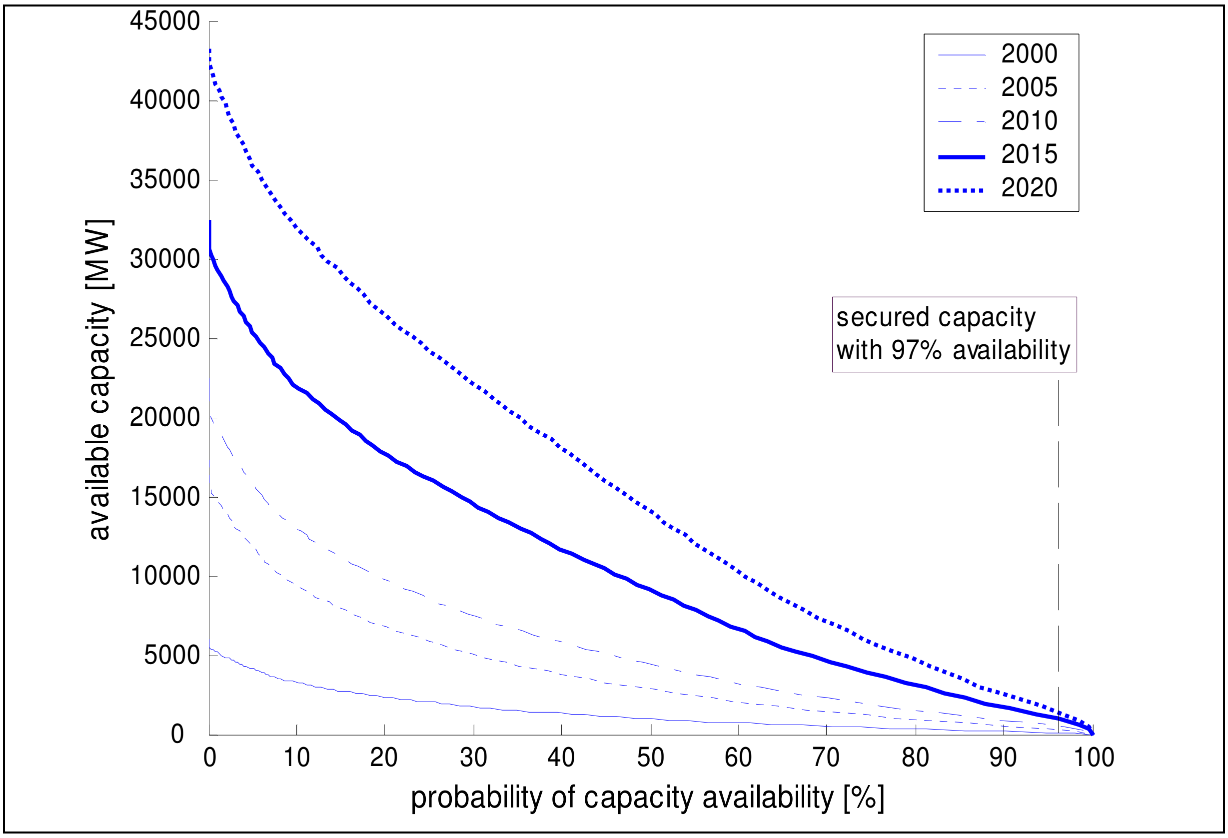

Figure 38: Secured wind power capacity (good wind year) in Germany as a function of capacity availability, derived from AEOLIUS wind power time series

Due to the geographical variations and differing wind speed distributions the secured capacity share is usually a non-linear function of the total installed wind turbine capacity. Taking into account that the secured capacity is quite low[174] and not very sensitive to the required security of supply [Dena 2005], the effects of wind energy for the substitution of conventional capacities are comparatively low when compared to other, freely dispatchable renewable electricity sources[175]. Although the relationships must be considered to depend on the country-specific circumstances of available wind potentials, it seems reasonable to assume that a similar tendency as in Germany also applies for the relationship in other countries. Thus, the requirements

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[174] Also other studies have examined the secured capacity of wind power installations. According to [Sontow 2000] the contribution of wind turbines to the secured capacity is about 5 – 26 % of the installed capacity, depending on the penetration, the optimisation of revision times and the wind park locations.

[175] When comparing the values for the secured capacity that can be derived from the wind model time series [Sensfuß et al. 2003] to values that have been derived from extensive wind turbine monitoring data (e.g. those of ISET for the Dena study [Dena 2005] p. 248], where, secured capacities lie above 5% up to 50.000 MW of wind power installed) it can be seen that the secured capacity calculated from the wind model time series is lower, i.e. it underestimates the contribution of wind power to the security of supply. This can be explained by the characteristic sites used in the caculations. The wind speed measurements at these sites are taken as representative for characteristic types of wind parks. When extrapolating the characteristics, the influence of simultaneously low wind speeds at the 22 characteristic sites (for Germany) is greater than when a larger number of sites is considered. In the latter case, the underlying higher number of geographically different locations with more differentiated wind speeds prevent the occurrence of such pronounced dips in the wind power time series.

have been applied to all countries in the model that make increased use of wind energy.

Secondly, the additional **reserve requirements** for wind power need to be taken into account in PERSEUS-RES-E. As drafted earlier in chapter 4.3.1, wind power feed-in has impacts mostly on the tertiary reserves. With the currently existing overcapacities in many European countries the provision of sufficient tertiary (and also secondary) reserve is possible. However, it has to be assured that these requirements are also met for the future energy system structures obtained by the optimisation model.

For each modelled time period the total amount of tertiary reserves required is introduced as a restriction into PERSEUS-RES-E (cf. section 7.3.3.4). This total amount takes into account both the general requirements and the additional requirements due to wind energy use[176] in the respective period. The appropriate total reserve requirements derived for each period are introduced into the model in an inequality constraint, which demands that the total tertiary reserve provided by the electricity system must be greater than the total required tertiary reserve at each time. While base load technologies with low load change flexibility and high load variation costs are regarded not to contribute to the reserve requirement, intermediate load technologies are regarded to contribute partly, and peak load technologies to contribute significantly to the coverage of necessary reserves.

Finally, also the **efficiency losses** in the conventional plant portfolio need to be taken into account in the long-term model. While wind power production replaces the use of conventional fuels, each produced unit of electricity can not substitute a complete equivalent of conventionally generated electricity. This incomplete replacement is mainly caused by inefficiencies in conventional power production induced by the fluctuating nature of wind power production.

The losses are due to more frequent load-variations, including an increased number of plant start-ups and shut-downs, and the operation of conventional capacities at reduced output levels in order to provide the necessary reserve (cf. chapter 6.6.2). As shown in the description of the calculations with AEOLIUS in this section, this changed operation characteristics leads to a reduced fuel-efficiency, as fuel consumption increases at partial load operation. Such behaviour necessitated by the provision of sufficient reserve capacity consequently results in an increased fuel consumption. This fuel consumption does obviously not directly contribute to the satisfaction of electricity demand, but nevertheless produces costs and emissions that need to be accounted for.

The amount of conventional fuels, which as a consequence of the fluctuating character of the wind energy feed-in can not be substituted, can be quantified with AEOLIUS and used for a corresponding penalisation of wind energy production (in terms of higher costs and emissions as compared to the complete substitution

[176] As determined from the AEOLIUS wind power feed-in time series or alternatively from [Dena 2005].

possible in the case of non-fluctuating renewable generation). Thus, even if a direct respresentation of the above effects in PERSEUS-RES-E is not possible due to the lower temporal resolution, they can be integrated making use of the AEOLIUS simulation results. For the case of Germany this is illustrated in Figure 39. Several new model elements are necessary to represent the efficiency losses, such as the producer *d-windlosses* with the unit *d-windloss*, which contains a process also named *d-windloss.*

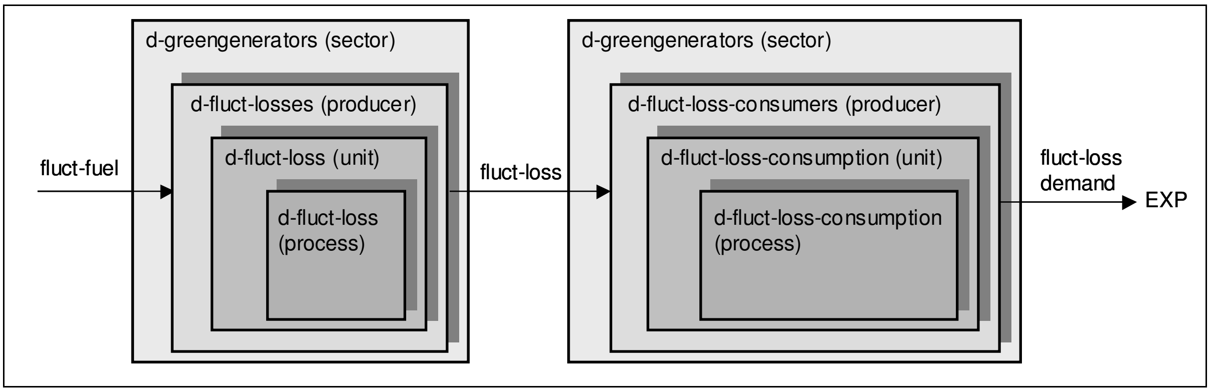

Figure 39: Modelling of fluctuation-induced efficiency losses in PERSEUS-RES-E

In addition, a demand flow is necessary to reproduce the less efficient conventional electricity generation in the model. This demand flow as well as the plant and process representing the fluctuation-induced fuel consumption and emissions are parameterised with data obtained from AEOLIUS simulation runs. With the electricity sector capacity structure of future periods determined by PERSEUS-RES-E, this structure is used in AEOLIUS to determine the fluctuation-induced emissions and costs[177]. To take this information into account in long-term energy system optimisation it is fed into a new PERSEUS-RES-E model run. The parameterisation in PERSEUS-RES-E is done as follows: The export flow *windloss_demand* is set equal to the amount of wind power production in region *xxx* in each period. Furthermore, the process *xxx-windloss* needs to be associated with the specific fluctuation-induced costs [cent/kWh] and emissions [g CO_2/kWh] of wind electricity production in each period as determined by AEOLIUS.

8.7 General framework conditions for the scenarios

The realisation of RES-E capacities until the end of 2002, which is the base year for the calculations of the mid-term potentials, is fixed in the model framework

[177] Another result of the adaptation of plant operation to an increasingly fluctuating residual load is increased thermal wear of power plant components due to frequent temperature changes. However, the resulting costs in terms of more frequent maintenance or component failure / exchange are hard to quantify and thus not accounted for in the model. A possible way to account for them would be in the fixed and / or variable costs of the virtual plant introduced to represent the fuel consumption and the emissions related to the reserve coverage. Another possibility would be to account for them in increased costs for the plants able to provide the reserves. However, the data availability and difficulties to isolate this effect would make a parameterisation extremely vague.

conditions. Any further expansion beyond the potentials realised in that year[178] is subject to optimisation. The future framework conditions like emission restrictions, renewable electricity quotas or financial incentives for renewable electricity generation determine how much of the available potential is realised in the upcoming optimisation periods.

8.7.1 Electricity demand and load structure

The electricity and heat demand to be covered by the generation units is the driving parameter of the model. For each modelled region the development of electricity demand over the time horizon as well as the load profiles are specified in order to take into account the interregional structure and the load characteristics of the individual regions. In Table 17 the assumed development of the annual electricity demand in the modelled regions within the time horizon of the model is summarised.

Table 17: Electricity demand in the model regions (based on [UNIPEDE 2001], [EC 1999], [IEA 2002a], [EIA/DOE 2002], [Prognos 2000], EIA Country Analysis Briefs (http://www.eia.doe.gov/cabs) and Fossil Energy International Country Reports (http://www.fe.doe.gov/international).

Model region		Electricity demand [TWh/a]		
		2000	2010	2020
AT	Austria	53.2	63.5	71.5
BE	Belgium	79.3	97.6	110.0
CZ	Czech Republic	52.5	62.9	68.9
DK	Denmark	32.4	35.5	38.5
FI	Finland	76.2	89.3	98.1
FR	Frankreich	411.0	478.0	588.4
DE	Germany	500.0	524.0	539.1
GR	Greece	43.5	60.4	74.8
GB	Great Britain	335.6	408.2	468.0
HU	Hungary	33.4	37.0	41.2
IT	Italy	278.6	372.0	474.3

Model region		Electricity demand [TWh/a]		
		2000	2010	2020
IR	Ireland	20.3	29.6	36.6
LU	Luxemburg	5.4	5.9	6.6
NI	Northern Ireland	7.4	9.0	10.3
NL	Netherlands	99.7	131.9	164.4
NO	Norway	106.5	117.8	129.6
PL	Poland	108.0	128.6	148.7
PT	Portugal	38.7	48.4	57.8
SK	Slovakia	26.7	31.4	41.2
ES	Spain	195.9	263.8	331.4
SE	Sweden	134.9	144.2	144.6
CH	Switzerland	52.4	60.1	67.1

While a total increase of 37.9%, or an annual average of 1.6%, is expected for the electricity demand in all modelled countries, the increase varies significantly from region to region. The modelled load profiles were derived from load data of the transmission system operators as well as from information available from utilities. For regions within the UCTE area the data is derived from the annual UCTE statistics[179] from 1994 to 2002. For the NORDEL regions the corresponding data sources are the

[178] The realised potentials were derived from Eurostat statistics [Eurostat 2005]. For wind energy the realised potentials until 2003 were given as fixed in the model.
[179] These can be found online on www.ucte.org.

NORDEL statistics[180] from 1999 to 2002. In order to eliminate the influence of load characteristics in a specific year, averages for the load characteristics were determined from these statistics. These load profiles are the basis for the modelled load levels within the temporal structure of the characteristic days of the model, which is described in chapter 8.2.

8.7.2 CO_2 emission allowances and certificate trade

Compliance with the regulations of the Kyoto Protocol and the Emission Trading Directive of the European Union are implemented as an additional restriction in the PERSEUS-RES-E model.

CO_2 emission allowances for the electricity industry in each country in the period from 2005 to 2007 are allocated based on the provisions of the National Allocation Plans [EC 2005d][181]. For this first trial period, sectors obliged to participate in the EU Emission Trading scheme have received emission allowances, which are usually based on historic emissions in a given base year. However, the differentiation of obliged sectors in the national allocation plans differs from country to country, which complicates the assignment of adequate amounts of emission rights to the uniformly specified sectors in the model. The latter in combination with the diverging allocation rules, which partly also include ex-post adjustments of the allowances, necessitates assumptions and generalisations when determining the allowances to be assigned in the model.

Only the emissions of the trial period from 2005 until 2007 are regulated, at the time of the calculations for this work the national allocation plans for the first commitment period from 2008 until 2012 were not completely available, and the requirements for future post-Kyoto commitment periods are not yet known.

Due to this lack of information concerning regulations, assumptions need to be made for the emission allowances in the period from 2008 until 2012 and from 2013 onwards. For the first Kyoto commitment period the 1990 emissions of the electricity industry minus the required reduction in accordance with the Kyoto Protocol and the EU Burden Sharing Agreement are allowed. For some countries (United Kingdom, Poland, Hungary) where the allocated amount for the first commitment period would be higher than that for the trial period, it has been assumed that the allowances in this period will not be increased above the assigned amount in the trial period. In the reference case it is further assumed that the allowances from 2013 onwards follow a linear extrapolation of the reduction rate that is required by the Kyoto commitments between 1990 and the first commitment period 2008 to 2012. The emission allowances for the modelled regions in the different time periods are summarised in Table 18.

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180 [NORDEL 1999], [NORDEL 2000], [NORDEL 2001], [NORDEL 2002].

181 For the time being, the other five greenhouse gases included in the Kyoto Protocol [UNFCCC 1997] are not regulated under the ETS Directive [EC 2003b]. Due to their limted relevance for the energy sector they are not considered in the following.

Table 18: Emission allowances for electricity generation (own calculations based on [IEA 2005b], [Eurelectric 2003] and National Allocation Plans [EC 2005b])

Country	Emissions in PERSEUS-RES-E [Mt CO_2/a]	Emission allowances [Mt CO_2/a]		
	2000	2005 - 2007	2008 - 2012	2020
Austria	13.717	11.731	10.745	9.942
Belgium	30.186	31.637	23.478	22.526
Czech Republic	63.488	59.119	42.583	40.731
Denmark	23.590	20.860	17.707	15.354
Finland	20.126	17.785	15.844	15.844
France	44.204	44.265	43.456	43.456
Germany	309.580	309.140	266.043	230.683
Greece	53.058	62.149	38.964	42.860
Hungary	24.401	18.235	18.235	13.069
Ireland	15.386	13.299	10.373	10.970
Italy	150.775	130.680	95.196	91.887
Luxembourg	0.000	0.000	2.927	2.358
Netherlands	55.126	37.937	38.056	36.841
Poland	166.577	154.655	154.655	112.386
Portugal	25.722	24.598	16.957	18.759
Slovakia	7.947	11.722	9.941	9.508
Spain	105.769	104.919	67.894	72.321
Sweden	10.443	7.009	6.887	7.019
United Kingdom	180.076	147.252	147.252	109.121
Total	**1300.171**	**1206.991**	**1027.191**	**905.637**

As a further parameter of the certificate trading scheme a penalty for non-compliance with the emission reduction obligations is taken into account in the model. In accordance with the Emission Trading Directive, the penalty is set to 40 €/tCO_2 for the first period between 2005 and 2007, while 100 €/tCO_2 have to be paid from the beginning of the first Kyoto commitment period in 2008 and onwards.

In the short to medium term the emission reduction options in the already existing power plant portfolio (e.g. fuel switch options) will be decisisve for complicance with the given emission constraints. In the longer term, the available technology options for the replacement or the expansion of existing capacities will be most important.

8.7.3 Discount rate

A diversity of choices and views concerning the discount rate to be used in energy system analysis calculations can be found in the relevant literature. For studies within policy consultancy and policy evaluation, common values chosen are between 3%

and 5%[182]. Such values represent a mean, risk-free real interest rate on the capital markets.

Contrasting to that, energy models developed to derive sectoral investment strategies as well as market models with a detailed modelling of the behaviour of actors use considerably higher discount rates with typical values between 8 %/a and 12 %/a[183]. The higher discount rate in these models is intended to account for an adequate rate of return for the additional market risk of the investment next to the risk-free capital market interest rate (cf. [Starrmann 2000, p. 94]). This value does thus more strongly reflect the decision behaviour of market actors/participants as well as the higher market risks of liberalised markets. Using a common percentage value for this risk premium does implicitly include the assumption that different power plant types/technologies bear comparable investment risks (cf. [Hoster 1996, p. 53 ff.]). Especially the influence of future fuel price risks needs to be critically discussed with regard to this assumption. The price development of different kinds of fuels has been characterised by notably differing volatilities in the past. However, deriving risk evaluations for future developments from these historic observations is at least problematic, especially in view of the general uncertainties with respect to the future developments of energy markets as well as supply structures. Due to unavailable data, which would allow a sector or technology specific differentiation of the market risk, the discount rate used for this work is based on an average, long-term interest rate of stock markets (cf. [Hoster 1996, p. 53 f.]). For the calculations a constant discount factor of 10 %/a is used throughout the time period covered by the model.

8.8 Implementation and analysis options

The code of the PERSEUS-RES-E model is programmed in GAMS (General Algebraic Modelling System [Brooke et al. 1998]). The concept of this programming language, which allows a code syntax similar to the formulation of mathematical problems, is specially suited for large and complex models. As the input files are combined to a description of the problem in the standardised MPS format, using different types of solvers is possible without any need to change the model itself. Thus, a variety of commercially available solver software can be applied. For the developed model the solvers CPLEX 8.0 and CPLEX 9.0 were used.

The model has been implemented as a PC version that can be run on most commercial PCs. Due to its complexity and the resulting large problem size, it requires state-of-the-art hardware components.

[182] For the joint modelling experiments conducted in the framework of the German Forum for energy system modelling (cf. e.g. [MEX IV 2004]), real discount rates of about 4 %/a are used.

[183] Compare e.g. [Hoster 1996, p. 53 f.]: 8 %/a, [Starrmann 2000, p. 94 f.]: 10 %/a, and [Grobbel 1999, p. 220 ff.]: 12 %/a. Concerning the necessity of higher interest rates to be considered in liberalised markets also refer to [Bunn et al. 1997b, p. 307 f.].

The model input parameters necessary to reproduce the energy supply system are handled via a Microsoft Access based data management system (see [Göbelt 2001] p. 105ff.]), which permits easy data handling and a fully automated link to the mathematical module. A graphical user interface is provided by the database system, helping to control all functions of the PERSEUS model system, except for the analysis of results. Model results are made available as formatted and structured text files by GAMS, which can be further processed in external MS Excel modules.

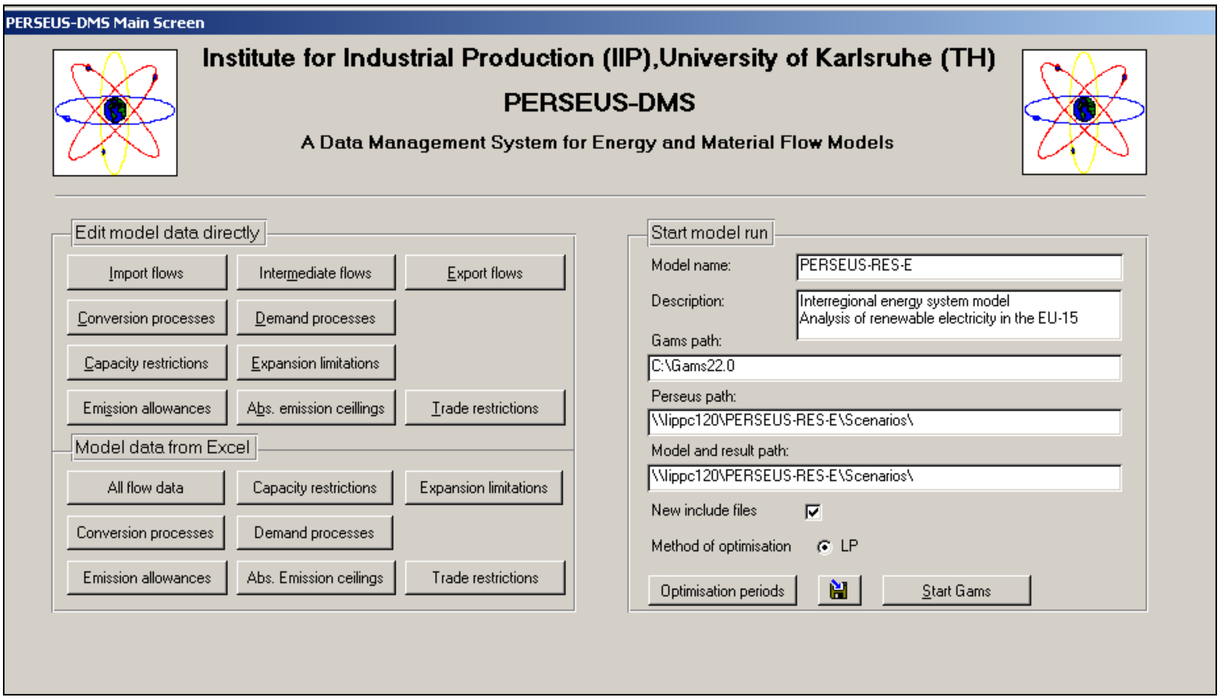

Figure 40: PERSEUS Data Management System (Main Screen)

The size of the linear optimisation problem is mainly determined by the number of optimisation periods. When five optimisation periods are considered, equal to a modelled time horizon from the year 2000 up to the year 2020 in steps of five years, the resulting mathematical problem consists of about 1.0 million variables, 1.1 million equations, and 6.0 million non-zero elements. Depending on the specifications for the scenarios, calculation times on a PC with 3.0 GHz processor and 2 GB RAM range from 30 minutes to several hours.

9 Model-based analysis of the role of renewable energy sources for electricity generation in the EU-15

In this chapter, the results obtained with the previously described PERSEUS-RES-E model are presented. Further, additional information obtained from AEOLIUS is used to integrate the effects of fluctuating power power production from wind energy (cf. chapter 5) in Germany and Spain. Starting with the key framework assumptions and the definition of a reference scenario, the resulting future evolution of the European electricity sector under alternative framework conditions is described. The general focus of this analysis will be on the possible role of renewable generation technologies and their interaction with conventional power generation in the EU-15 Member States. Moreover, the results for exemplary Member States with quite diverse power sectors will be discussed more specifically. This includes Germany with its favourable renewable electricity feed-in law and its geographical situation in the centre of Western Europe, which makes it a hub for inter-regional electricity exchange. Moreover, France and Spain are included[184]. While Spain, similar to Germany, has a fossil-dominated generation mix, its possibilities for electricity exchange are limited. Contrary to that, the French power sector is characterised by an extensive use of nuclear power and low CO_2 emissions. Besides the capacities and the power production shares of conventional and renewable technologies, the CO_2 emissions, and the resulting interregional power exchange, also the expected cost developments are summarised. This includes marginal power production costs, the costs of RES-E use, and the marginal CO_2 reduction costs. Special consideration is further given to the German electricity sector within the context of the surrounding regions.

The existing structure of the European electricity supply systems is still largely the result of national energy policies from the time before the idea of a single and liberalised European electricity market started to take shape. While this is one major reason for the heterogenous structures of today's electricity systems, another reason is the differing indigenous availability of primary energy sources, such as local coal or hydro power resources, as well as the geographically determined variation of efforts necessary for the transport of different kinds of imported fuels. Out of various political and economic considerations (see chapter 2), the framework conditions for the energy supply infrastructure have changed during the last two decades. These changed framework conditions include the lost competitiveness of indigenous coal versus imported coal, moratoria or phase-out regulations for nuclear power, the international climate change mitigation process, as well as the promotion of renewable energy sources. Seen in this context, the structural changes in the electricity sectors of the European countries described in the following scenarios

[184] Together with the United Kingdom, these are the countries with the largest mid-term potentials for renewable electricity generation in the EU-15 (cf. chapter 3.4).

reflect the adaptation of the electricity system on the way to achieve a cost-minimised supply infrastructure in the future, under different existing or expected framework conditions.

9.1 Definition of a reference scenario

For the reference scenario, the following assumptions are made for the current situation and the future development of the European electricity sector:

No requirements are made as to the amount of renewable electricity production to be achieved in 2010. While the renewable capacities installed until the end of 2002 are considered as fixed in the model, no mandatory targets or promotion schemes are considered for the use of renewable electricity sources. This scenario thus represents a situation in which renewable and conventional technologies compete with each other on a free market with CO_2 emission caps as the only restriction.

A relatively stringent emission reduction path is introduced, essentially based on an extrapolation of the EU-Burden Sharing Agreement. With the Emission Trading Scheme beginning from 2005, the utility sectors in the modelled regions are equipped with emission allowances derived from the National Allocation plans and linearly decreasing allowance volumes from 2013 onwards, as described in chapter 8.7.2. In the case that these allowances are not sufficient to cover the emissions of power production in this country, additional CO_2 emission rights can either be purchased from sectors that do not fully use their own allowances, or a penalty has to be paid. As the total emissions in the participant countries' sectors are limited to the sum of emission allowances of all countries (cap-and-trade system) and a perfect market for electricity as well as for CO_2 emission certificates is assumed in the optimisations, emission reductions are chosen to be realised where they are cheapest. This implies a close interconnection between the markets for emission certificates and power, as power production from countries with an emission intensive power sector can partly be shifted to countries that produce electricity with less CO_2 emissions, even if production costs are somewhat higher.

Assuming business-as-usual policies in the EU-15 Member States, the option to construct new nuclear power plants is limited to France, Finland, and Great Britain. Furthermore, the construction of new nuclear capacities is an allowed option in the new Member States Poland, the Czech Republic, Slovakia, and Hungary. In all other modelled countries new nuclear capacities may not be constructed. Moreover, for Germany the phase-out treaty for nuclear electricity generation is considered, which limits the amount of nuclear power that may be produced from the year 2000 onwards to a total of 2623.3 TWh (cf. section 2.2.2.3).

For the different conventional energy carriers the price development indicated in section 8.5.1 is given, additionally incorporating their availability and the regionally differentiated price surcharges for transport and taxes. For the renewable potentials the regional energy-carrier specific cost curves as described in section 8.6.1 are used. All interconnector lines between the model regions are considered and parameterised according to the currently installed transmission capacities plus foreseeable expansions. Each line is characterised by its NTC values, as described in chapter 8.4.

9.2 Evolution of the European electricity system in the reference scenario

9.2.1 Structure of power generation and of the capacity mix

In Figure 41 the forecasted mix of capacities and power generation from the different energy carriers in the EU-15 is depicted for the modelled time horizon from the year 2000 to 2020. Together with Table 19 it gives an overview over the restructuring process in power generation that is expected to take place in the different European regions. This restructuring process is not only limited to shifts in the importance of the different generation technologies, but also affects electricity imports and exports between the regions. The latter are examined more closely in section 9.2.2.

In order to avoid having too many categories in the following figures, the 15 renewable energy carriers are partly aggregated for the representations. Where not split up into more detail, “wind” contains both onshore and offshore wind power, and “biogas” summarises the energy carriers biogas, landfill gas and sewage gas. Similarly, if not specified separately, “biomass” stands for solid biomass and the biodegradable fraction of municipal solid waste and “solar” includes both photovoltaics and solar thermal applications. The “hydro” category includes both small scale and large scale hydro power installations, while “geo+other” contains conventional geothermal and hot dry rock installations, as well as wave and tide installations.

While the demand in the EU-15 increases continuously throughout the time horizon, an only marginally increased total installed capacity in 2005 indicates a more intensive utilisation of existing capacities, before new capacities are constructed. When comparing the beginning and the end of the modelled time horizon, the entire additional demand encountered until 2020 is covered by new natural gas fired capacities. The increasingly stringent emission restrictions introduced by the ETS and afterwards (as described in chapter 8.7.2) are triggering this structural change to the more expensive, but less emission-intensive energy carrier natural gas. Moreover, the capacities as well as the production of existing CO_2-intensive technologies are to a very large extent replaced by natural gas. Compared to the base year 2000, power production from lignite is reduced by 126 TWh in 2020, equivalent to a decrease of 71%. The corresponding values for fuel-oil are 124 TWh or 99% less, and for hard coal the decrease is 269 TWh or 61%.

The electricity production share of natural gas fired power plants grows more strongly than their capacity share until 2010. This means that these units are operated at increased full-load hours. Thus, natural gas fired units do not only generate peak load electricity as before, but also take over a share of the intermediate load. After 2010 and partly after 2015 the average utilisation decreases again in those countries with a strong wind energy growth. This is due to the provision of additional tertiary reserves, for which flexible gas fired power plants with a comparatively low capital intensity are the favoured choice. In countries with no or less wind energy use the increased full-load hours up to 5000 full-load hours and more can be observed throughout the whole time horizon[185].

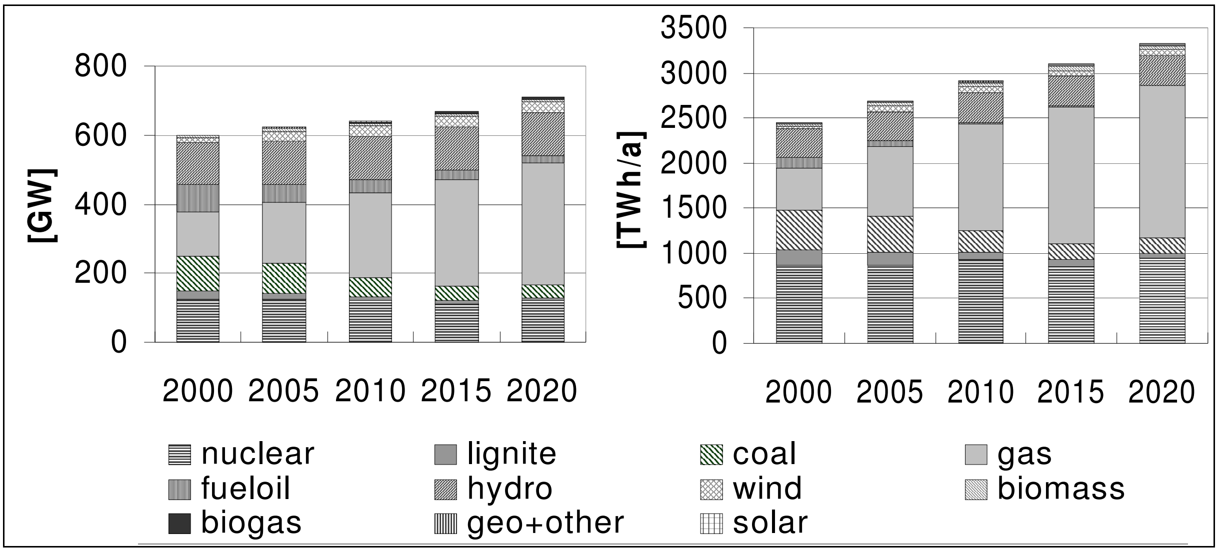

Figure 41: Evolution of installed capacities and power production in the EU-15 (REFERENCE)

Only a small dip occurs in the nuclear capacities in 2015, caused by the German nuclear phase out. This gap is almost completely filled up again in 2020, and the missing nuclear production is overcompensated due to an increased production of the existing reactors and new ones constructed in other countries, mainly in France and the United Kingdom, but also in Finland and the four modelled new EU Member States. The installation and the use of renewable capacities does not increase significantly, as without financial incentives or quota obligations only the cheapest additional potentials are sufficiently economical to compete with other options of CO_2 abatement. Compared to the base year 2000, these potentials (mainly biomass, biogas, some wind, and small hydro) lead to a total of about 85 TWh (+22%) of additional renewable electricity production in the EU-15 by 2020[186].

In the following, the developments in the power sector of some selected EU-15 Member States will be described in more detail.

For Germany (see Figure 42) the optimisation results indicate that the existing capacities in the base year could be reduced from about 112 GW to about 107 GW in 2005 by utilising the most efficient available capacities up to the possible maximum full load hours. From 2005 until the end of the time horizon there are only minor

[185] The effects of additional reserve requirements by increased wind power capacities are drafted in more detail in chapter 9.3.5.

[186] This figure already includes the renewable electricity production realised until the end of 2002, which is fixed in the model.

changes in the total installed capacity. Hard coal and lignite capacities are replaced by natural gas fired units.

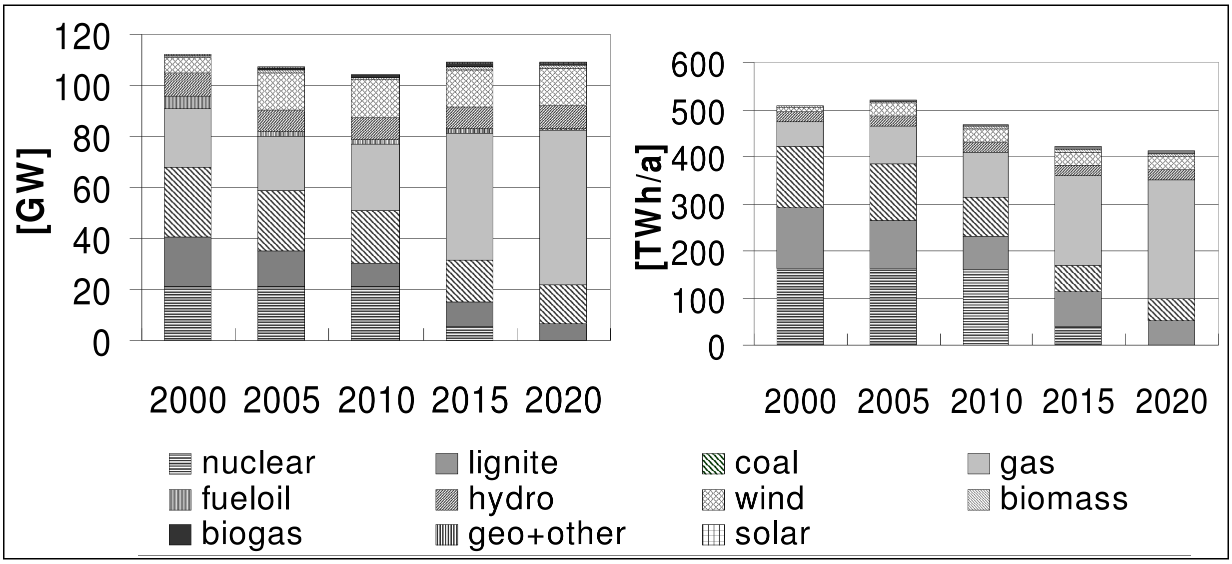

Figure 42: Evolution of installed capacities and power production in Germany (REFERENCE)

The same is true for the nuclear capacities with their CO_2-free power production, which are decommissioned partly in 2015 and fully in 2020. Although the extensive construction of natural gas fired capacities compensates for the decommissioned fossil and nuclear capacities and leads to 251 TWh of electricity produced from natural gas in 2020, this type of power plant does not reach the same amount of full-load hours as the base load nuclear technology. This fact is reflected in the evolution of total power production, which from 2000 to 2005 rises only slightly from 514 TWh to 526 TWh and then continuously decreases to a minimum of 414 TWh in 2020. As a result of the beginning certificate trade and later the increasingly CO_2-intensive power production due to the nuclear phase-out, less CO_2 intensive power imports are the most favourable option to cover the remainder of the electricity demand in Germany. Imports reach a maximum value of almost 149 TWh in 2020, while CO_2-intensive coal production is cut to 49 TWh, i.e. 62% less than the initial production of 130 TWh in 2000. Almost identically, power production from lignite decreases by 61% from 132 TWh in 2000 to 51 TWh in 2020.

The results for France show that French overcapacities are reduced by 11 GW in 2005, from an initial capacity of 114 GW in the base year (see Figure 43). From then onwards capacities remain practically constant at 101 GW to 103 GW until 2015, despite a continuously increasing power production over the whole time horizon. This is mostly due to an increased utilisation of power plants up to the maximum possible operating hours and the construction of more efficient power plants in later periods. A significant increase of total capacity happens in 2020, when with 116 GW the capacity installed in the year 2000 is slightly exceeded. About 13 GW of nuclear capacities are constructed in this last period, and about 7 GW of gas fired capacities.

While power production from coal almost completely disappears from 2010 onwards and the few existing oil fired capacities are reduced continuously over the whole period, the construction of new gas fired capacities compensates part of this loss. They are used to substitute part of the heat production formerly covered by the oil-fired plants and, due to their flexibility (especially when compared to nuclear power plants) and with gas being less expensive than oil, also for peak load and intermediate load electricity generation. The production of nuclear power in France increases notably (by 85 TWh) in 2010 and by another 73 TWh in 2020. Apart from the already installed RES-E capacities no significant additional development of renewable electricity use takes place (70 TWh in 2000 vs. 74 TWh in 2020).

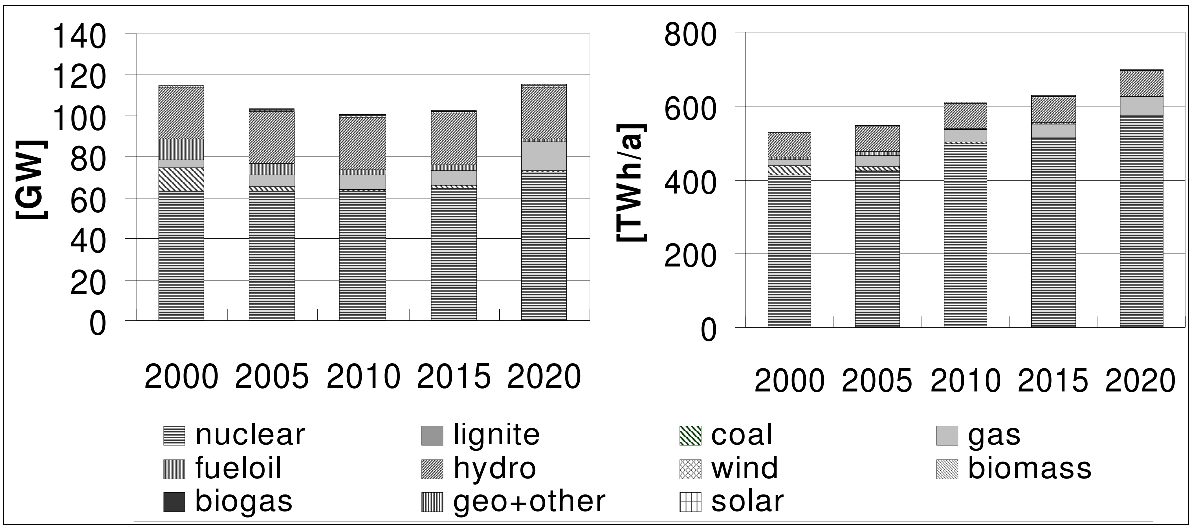

Figure 43: Evolution of installed capacities and power production in France (REFERENCE)

Total power production is higher than the domestic demand throughout the whole time horizon, and thus exports remain on a high level between 54 TWh (2015) and 88 TWh (2010). Although a lot of electricity is exported, capacities and production are further increased in the later periods. This is due to the the ability to produce comparatively inexpensive and practically CO_2 free electricity from the extensive use of nuclear technology. This electricity is exported to practically all of its neighbours, most of it to those countries with more CO_2 intensive power sectors, such as Germany, Italy and Spain.

Figure 44 shows the evolution of the power sector in Spain. Despite a relatively emission-intensive power production, capacitiy and production increase to fulfil the rising demand. Different from Germany, which, concerning emission intensity, is in a worse situation due to the nuclear phase-out, the limited possibilities for power exchange make more indigenous power production necessary in Spain. This makes the country become one of the largest purchasers of emission certificates (see section 9.2.4).

Emission-intensive existing lignite capacities are decommissioned until 2010 and not replaced by more efficient ones. Their production and the increased demand is covered by newly constructed natural gas fired capacities. Their share in the electricity mix grows from 3 GW and 18 TWh in 2000 to 18 GW and 85 TWh in 2010, and finally to 32 GW and 139 TWh in 2020.

Existing hard coal fired power production capacities (about 11 GW) are utilised up to the maximum possible full-load hours from 2005 onwards. About 2 GW are decommissioned in 2015 and replaced by 3 GW of modern and more efficient units in 2020.

The existing nuclear capacities and production remain almost constant throughout the time horizon, with the exception of the oldest boiling water reactor capacities, which are partly decommissioned in 2015. Although they do not deliver a noteworthy contribution to power production any more, a part of the oil fired capacities (oil fired gas turbines) remain in the mix until 2020, as they can satisfy a part of the general tertiary reserve requirements and those necessary for wind power production.

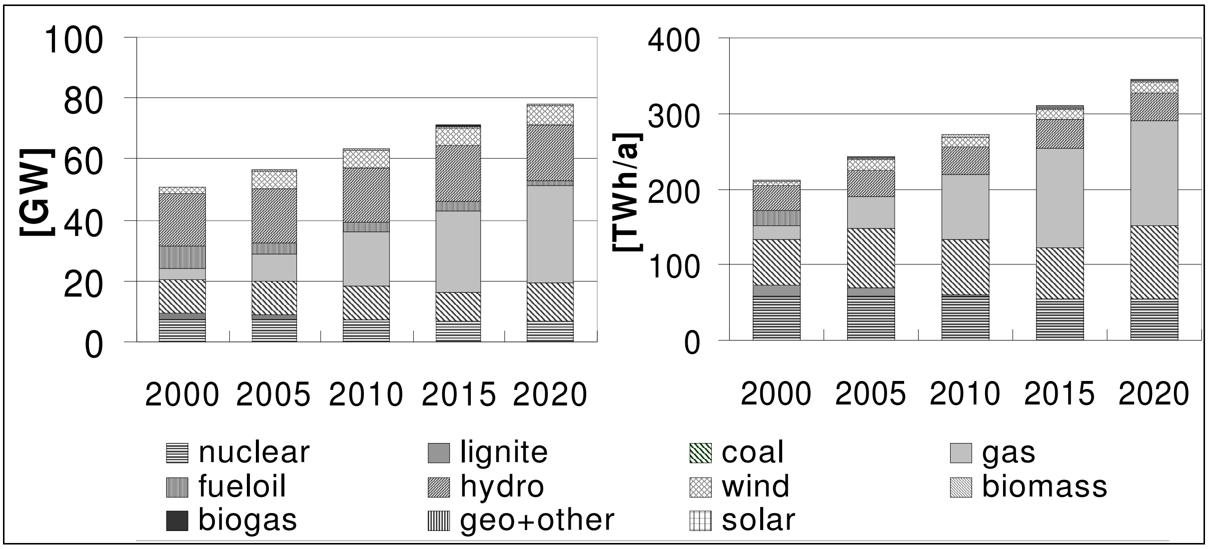

Figure 44: Evolution of installed capacities and power production in Spain (REFERENCE)

As already observed for the other countries above and for Europe as a whole, wind energy capacities and renewable electricity use in general are not or only marginally expanded beyond the realised capacities in 2002 without incentives or mandatory targets for renewables implemented.

9.2.2 Interregional power exchange

As an interrelated aspect of the capacity structure and the power generation mix in each region the power exchanged by imports to and exports from the modelled regions is interesting to be analysed. Generally, power is exported from a region, when the marginal costs of power generation in this region are lower than those in a neighbouring region (cf. section 9.2.3). This relative advantage can also be limited to specific load segments or hours of the day, e.g. comparatively low priced base load production by lignite or nuclear power plants and less expensive peak load generation by storage or pumped storage hydro power plants instead of using gas turbines. Since the introduction of the European emission trading scheme, the relative economic advantage of power generation options in neighbouring regions is increasingly influenced by differences in the CO_2 intensity of power generation options.

In Table 19 an overview is given over the development of the balances of imports and exports from 2000 to 2020. The countries with increasing electricity imports usually are those with an emission intensive electricity sector and with no or a relatively more expensive access to less CO_2-intensive options of fuel supply and capacity expansion. Depending on their emission allowances, they are usually able to sell emission certificates in return (e.g. Germany, cf. section 9.2.4). Vice versa, regions with less expensive options for an emission-reduced generation of electricity produce power in excess of their own demand, with the excess power being exported. In turn they may need more CO_2 certificates to cover the additional emissions (e.g. the Netherlands). Within the existing restrictions of transmission capacities and fuel availabilities power production is thus relocated in a way that produces more power where production is less emission intensive. However, some countries with restricted transmission capacities and CO_2 intensive power production have no possibilities for the import of large amounts of less CO_2-intensive power. Instead, they have to produce power themselves in a more emission-intensive way and buy the necessary certificates on the market. This is the case e.g. for Spain and Italy.

Table 19: Electricity production and electricity exchange balances in the EU-15 (REFERENCE)

	Power production [TWh/a]			Power exchange balance [TWh/a]		
	2000	2010	2020	2000	2010	2020
AT	57.6	62.9	66.4	-4.6	0.3	4.7
BE	81.3	101.4	126.0	5.0	3.5	-9.0
DK	34.0	38.9	49.0	0.3	-1.3	-8.1
FI	65.7	86.9	107.6	13.9	6.4	-5.0
FR	537.2	617.5	705.5	-73.5	-88.4	-63.1
DE	513.9	472.9	414.0	13.2	78.6	148.7
UK	350.2	441.5	508.3	14.3	4.8	1.8
GR	48.0	70.2	86.3	0.0	-2.6	-3.9
IE	21.2	33.1	43.2	1.4	-0.3	-2.6
IT	258.2	353.9	457.5	39.6	52.2	51.7
LU	1.3	9.3	17.9	5.6	-1.4	-10.3
NL	83.9	147.1	189.4	20.0	-9.5	-17.8
PT	41.7	58.5	69.1	1.6	-5.0	-5.3
ES	215.5	273.2	345.7	3.7	14.8	15.5
SE	154.8	166.9	153.3	-7.4	-9.8	3.9

As an example for the changing inter-regional power flows, the imports to and exports from Germany in the years 2000 and 2010 are shown in Figure 45. Germany is a central hub for the power exchange flows in the EU-15. Without CO_2 restrictions in place in the base year 2000, Germany imports a total of 32 TWh from Denmark, Poland, the Czech Republic, Austria, and, most importantly, from France. Exports totalling almost 19 TWh go to the Benelux region and to Switzerland.

As indicated already the CO_2 emission restrictions and the phase-out of nuclear power make electricity production in Germany less attractive than power imports from neighbouring regions with less emission-intensive and cheaper power production options. Already in 2010 Germany imports a net total sum of almost 79 TWh from its neighbours[187]. The largest share of German power imports comes from France, but additionally Germany can import electricity from other neighbouring countries, which have an electricity production that is less expensive despite CO_2 restrictions.

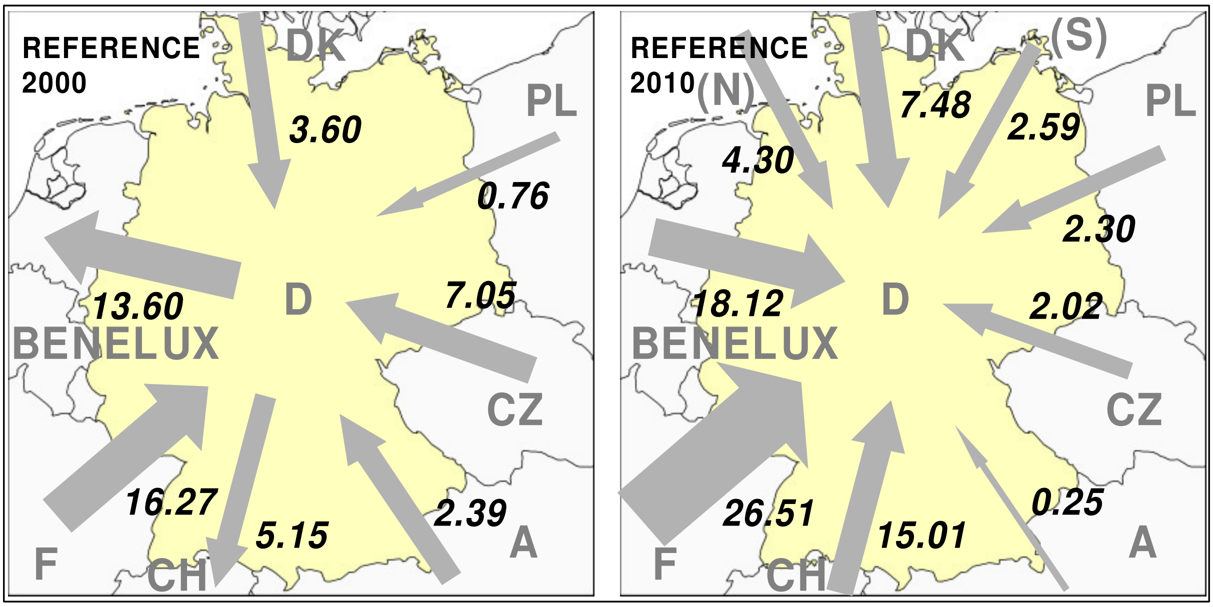

Figure 45: Development of the German electricity exchange balance (REFERENCE)

9.2.3 Marginal costs of power production and of CO_2 emission abatement

The marginal costs of power production in the individual time slots of the model can be used as an indicator for the expected development of power prices. They are derived from the shadow price of the restriction that stipulates the coverage of electricity demand (see also chapters 7.3.2.2.1 and 7.3.4.4). As the focus of the analysis is on the long-term development of the market environment in the European electricity sector and not on the forecast of short-term price developments, a weighted annual average of the marginal costs is used in the following descriptions.

[187] Switzerland does not participate in the ETS, and consequently no CO_2 restrictions can be assigned to its electricity sector. Instead, it is intended to regulate emissions by a CO_2 tax, which is not yet fixed. Thus, an assumption needs to be made about the restrictions of the Swiss electricity sector. Two cases have been distinguished in the model calculations. By default, emissions are left unrestricted in the calculations. In this case, natural gas fired power plants are built and the electricity is exported. If it is alternatively assumed that the CO_2 tax will be able to stabilise the emissions on the level of the year 2000, the electricity exports from Switzerland to Germany are partly substituted by additional electricity production in Germany and partly by increased imports from its neighbouring regions. In this case the leakage of CO_2 emissions is prevented and leads to an increase of the marginal CO_2 abatement costs by a maximum of +5.5% or 1.3 Euro/tCO_2 in 2015.

In Table 20 the evolution of marginal costs in the EU-15 is shown. The increasing tendency that can be observed is not only caused by rising fuel prices, but also by the restrictions on CO_2 emissions that have to be fulfilled.

Table 20: Evolution of marginal costs of power production in the EU-15 (REFERENCE)

	2000 [cent/kWh]	2005 [cent/kWh]	2010 [cent/kWh]	2015 [cent/kWh]	2020 [cent/kWh]
AT	1.79	2.74	3.47	3.67	3.91
BE	2.22	3.18	3.61	3.93	4.17
DK	1.81	3.08	3.63	3.96	4.24
FI	2.40	3.45	3.84	3.90	3.98
FR	1.58	2.72	3.03	3.92	4.00
DE	1.94	2.97	3.76	4.22	4.58
UK	2.88	2.99	3.37	3.78	3.74
GR	3.84	3.70	4.09	4.38	4.67
IE	3.38	3.35	3.77	4.03	4.31
IT	4.17	4.03	4.41	4.71	5.03
LU	2.29	3.23	3.67	3.98	4.22
NL	2.36	3.17	3.63	3.93	4.17
PT	2.98	3.43	3.89	4.27	4.60
ES	2.77	4.08	4.71	5.08	5.31
SE	1.79	3.15	3.58	3.89	4.16

Already from 2005 the natural gas fired power generation capacities are not only used for peak load generation, but are operated at significantly higher full-load hours (above 4000 full load hours per year in many European countries) to provide intermediate load power. This leads to increased costs of power generation, and since intermediate load units set the marginal price for some time slots, the increase is also reflected in the development of the annual average marginal costs. Those countries with the least emission-intensive energy systems, as e.g. France, are able to meet the CO_2 restrictions more easily than countries with a fossil-based generation system like Germany, Spain or Italy. Consequently, the increase of marginal costs in the latter countries is higher throughout the whole modelled time horizon.

The marginal reduction costs for CO_2, which can be interpreted as an indicator for the future certificate prices, are shown in Table 21.

Table 21: Marginal costs of CO_2 emission reductions (REFERENCE)

	2005-2007	2008-2012	2013-2017	2018-2022
Marginal CO_2 abatement costs [€/tCO_2]	9.9	20.4	23.7	25.4

Different from the physically restricted power flows among the regions, the exchange of CO_2 certificates has no technical limits. As no regulations by trade limits are introduced in the scenarios the price can reach an equilibrium all over Europe. Along with a growing relative shortage of emission allowances due to the rising electricity demand in the European countries, marginal reduction costs increase from 9.9 € in 2005 up to 25.4 € in 2020.

9.2.4 CO_2 emissions and emission allowance trading

Contrary to the increase caused in the marginal power production costs, the CO_2 restrictions have a positive impact on the total and specific emissions of electricity generation in the countries participating in the European ETS.

Despite a decline of specific emissions in most EU-15 countries in future periods, the increasing electricity demand causes the total amount of emissions in the EU-15 to rise throughout the modelled time horizon. Significant reductions only occur in the United Kingdom. However, the majority of emission reductions necessary to comply with the overall emission cap is carried out in the four new Member States included in the model, which all become sellers of emission rights (see Table 22).

Table 22: Emissions and certificate trading balances in the ETS participant countries (REFERENCE)

	Emissions [$MtCO_2/a$]		Certificate trading balance [$MtCO_2/a$]	
	2010	2020	2010	2020
AT	13.6	14.3	2.9	4.1
BE	27.1	37.4	3.7	14.6
CZ	46.5	31.2	3.9	-10.0
DK	19.1	20.9	1.1	4.5
FI	19.1	17.7	3.3	1.9
FR	31.5	31.1	-12.0	-12.4
DE	217.3	218.5	-72.9	-49.4
UK	152.3	115.1	5.0	-24.8
GR	24.4	29.4	-14.6	-13.5
HU	8.5	6.0	-9.7	-11.8
IE	16.4	18.2	6.0	7.3
IT	133.3	161.1	38.1	68.4
LU	2.6	5.7	2.0	5.2
NL	69.5	78.5	31.5	41.4
PL	130.2	64.7	-24.5	-86.2
PT	15.4	18.2	-1.5	-0.6
SK	4.9	3.3	-5.0	-6.3
ES	111.1	137.7	43.2	65.7
SE	11.2	14.4	3.3	6.5

Due to a radical restructuring from inefficient, coal and lignite based electricity generation to new natural gas and nuclear power plants, the countries are able to cut their emissions below the assigned allowances. Poland is the most important seller of emission certificates.

Both France and Germany are net sellers of certificates. In France this is achieved by using even more nuclear power and almost no additional coal and oil fired generation. In the German electricity sector, the nuclear phase-out is compensated by stepping up the power production from natural gas and a substantial increase of power imports. At the same time, coal and lignite power production are heavily reduced. With their limited options for further electricity imports and their continued CO_2 intensive electricity production, Spain and Italy become the most important certificate buyers.

9.3 Evolution of the European electricity system in the scenarios

9.3.1 Definition of the scenarios

The future use of renewable energy technologies in power generation, which will determine their mid-term market penetration, does not only depend on the technical and economic characteristics of the technologies themselves as compared to conventional power generation technologies, but also on a number of other general framework conditions. Often these framework conditions are of a political nature, as e.g. in the case of CO_2 restrictions, renewable targets, or the German nuclear phase-out. They can also be of an economic nature, as e.g. in the case of the fuel price development, or of a technological nature, when technological barriers exist that may either be overcome or remain limiting in the modelled time horizon. Any change in the development of one of these framework conditions or their combination has effects on the relative competitiveness of energy technologies in general, and that of renewable electricity generation in particular.

It is thus the aim of this model-based analysis to characterise the economically optimised future evolution of the power system under a range of possible developments of those framework conditions. A scenario-based approach, wich takes its starting point in the current general political, technological, economic and ecological conditions in the relevant European and national contexts, has been chosen to achieve this goal. The set of scenarios chosen to characterise the influence of a variety of external restrictions and conditions on the European power system is listed in Table 23.

The scenarios introduced can be divided into three thematic sets. In the first set of scenarios, the influences of the major parameters related to emission reductions on the electricity system in general and especially on renewable electricity use are analysed in more detail. First of all, this is the given CO_2 restriction itself, and secondly the influence of different price developments for natural gas as the most favoured conventional CO_2 reduction. These two scenarios in the first set allow to identify, whether and to what extent renewable electricity potentials become viable in a purely cost-based competition, i.e. without promotion, only under CO_2 restrictions and extreme price increases for CO_2 reduction options in conventional power generation.

In the second set of scenarios, the cost-minimised distributions of renewable and conventional electricity use across the model regions and over time for different design options of targets and incentives for the use of renewable electricity are derived. This allows also to assess the influence of the promotion of renewable electricity use on marginal costs of power generation and CO_2 abatement, as well as the additional costs caused by the renewable electricity use.

In a third set of scenarios, the technical aspects of the integration of fluctuating renewable electricity as well as modelling aspects are investigated more closely.

Table 23: Scenario definitions

Criterion	Scenario	Description	Objective
CO_2 restrictions	REFERENCE	Emission allowances 2005 to 2007 according to NAPs. 2008-2012 according to Kyoto obligations. Linear extrapolation from 2013-2020.	Analysis of CO_2 restrictions on the power generation mix and power exchange.
	CO_2_UNLIMITED	No ETS, CO_2 emissions unlimited during the modelled time horizon 2000-2020	
Natural gas price	REFERENCE	Evolution of fossil fuel prices on the world market as given in Table 12 on p. 132.	Analysis of the influence of increasing prices for natural gas on the rentability of RES-E and on the generation mix in general.
	GAS+50	Linearly increasing surcharge on the world market gas and oil price from 0% to +50% between 2000 and 2015. Constant price surcharge of +50% after 2015.	
	GAS+75	Linearly increasing surcharge on the world market gas and oil price from 0% to +75% between 2000 and 2015. Constant price surcharge of +75% after 2015.	
RES-E targets	REFERENCE	No RES-E targets for 2010 or 2020. No continuation of RES-E incentive schemes in the EU-15 from 2003 onwards. Installed RES-E capacities as of December 2002 are considered and the tapping of additional potentials is allowed.	Analysis of the influence of national or European targets on the use of RES-E potentials (type of RES, country, time period).
	TARGETS_2010	Country-specific targets for 2010 in line with the RES-E Directive.	
	TARGETS_national	Country-specific targets for 2010 in line with the RES-E Directive. For 2020 a binding overall EU target of 1,166 TWh from renewable sources is implemented.	
	TARGETS_EU	EU-wide targets for 2010 (according to the sum of the country-specific targets in the RES-E Directive) as well as for 2020.	

Criterion	Scenario	Description	Objective
RES-E incentive schemes	REFERENCE	No RES-E targets for 2010 or 2020. No continuation of RES-E incentive schemes in the EU-15 from 2003 onwards. Installed RES-E capacities as of December 2002 are considered and the tapping of additional potentials is allowed.	Analysis of the influence of financial incentives.
	INCENTIVES	Continuation of current RES-E incentive schemes in the EU-15 Member States from 2003 until the end of the modelled time horizon. Installed RES-E capacities as of December 2002 are considered, the tapping of additional potentials is allowed. For countries with quantity-based incentives, the fulfilment of the 2010 targets according to the RES-E Directive is stipulated, based on the actual cost of the potentials without financial incentives.	
Fluctuation-induced effects	REFERENCE	Additional reserve demand due to wind energy use taken into account, as in all previous scenarios. Fluctuation-induced losses not taken into account.	Quantification of fluctuation-induced reserve capacity demand and efficiency losses.
	NO_RESERVE	Same conditions as specified for TARGETS_EU, but no additional reserve demand taken into account.	
	TARGETS_EU_FLUCT	Fluctuation-induced efficiency losses are taken into account.	
Limitation of the expansion rate of RES-E use	REFERENCE	Linearly increasing bound on the allowed maximum utilisation [GWh] of available mid-term potentials from 2003 to 2020. In addition, the capacity expansion rate [MW/a] is limited to 150% of a linear increase between 2003 and 2020.	Analysis of the influence of unrestricted vs. limited RES-E expansion rates.
	TARGETS_EU_INF	Linearly increasing bound on the allowed maximum utilisation of available mid-term potentials from 2003 to 2020. No limitation of the annual expansion rate. Otherwise same conditions as specified for TARGETS_EU.	

9.3.2 Influence of CO_2 restrictions

In order to enforce the implementation of climate change mitigation activities under the Kyoto Protocol, the European Union has introduced an emission trading scheme (cf. chapter 2.2.2.1). Due to the induced shortage of CO_2 emission allowances under this scheme, CO_2 emissions must be managed as a new production factor by the obliged actors. As a major emitter of CO_2 the energy sector is particularly affected by the restrictions on CO_2 emissions and the price for CO_2 emission allowances, which is based on the marginal costs for CO_2 mitigation options as an indicator. The influence that differently stringent reduction policies have on the price of emission allowances can be quantified by the model, along with the influences of this limitation on the capacity structure of the electricity system.

The substantial structural changes in power generation induced by increasingly stringent limitations of the allowed CO_2 emissions have already been discussed in the description of the REFERENCE scenario. Due to the lower emission factor compared to other fossil generation options, the use of natural gas for power generation is favoured with increasingly strict limitations of emission allowances. Simultaneously, the utilisation of more carbon intensive technologies, i.e. lignite and coal fired power plants, decreases. A gradual substitution of lignite and coal fired capacities by natural gas fired combined-cycle power plants can be observed in most model regions. Along with higher full load hours for the natural gas combined-cycle capacities and a decreasing utilisation of coal fired capacities this indicates that power production based on coal and lignite is pushed out of the intermediate load and at least partly also out of the base load range.

In order to assess the effects of emission limitations in the REFERENCE scenario on the power generation structure it can be compared to the power generation structures resulting from a scenario without any CO_2 limitations (i.e. without the ETS). The resulting effects shall be exemplified in the evolution of the power generation mix in the EU-15 and in Germany, which are depicted in Figure 46.

With no CO_2 restrictions in place, the increasing electricity demand is almost exclusively covered by fossil fuel based electricity generation. Within the EU-15 the use of lignite increases by 125 TWh (+70%), that of coal by 345 TWh (+78%), and that of natural gas by 761 TWh (+166%) throughout the modelled time horizon. Also the use of nuclear energy is influenced by the level of the emission restrictions. In the REFERENCE scenario, additional nuclear power plants for base load power production are constructed in those regions where this option is not excluded. In the case of no emission restrictions, i.e. with the possibility to emit CO_2 for free, no additional nuclear capacities are built and the existing ones are gradually decommissioned as they reach the end of their technical lifetime. Thus, nuclear power production decreases by 213 TWh, or 25%, from the year 2000 until 2020.

Instead, capacities fired by lignite, coal and natural gas are built, as they provide the economically most attractive coverage of base load and intermediate load under these conditions. More efficient lignite power plants are constructed from 2010 onwards, with a total production of 303 TWh in 2020, compared to 178 TWh in the year 2000. In the contrary case of very strict emission reduction obligations, more CO_2 free nuclear power capacities are constructed where possible in the EU-15 and especially in the four new Member States in the model, along with the increased utilisation of natural gas as the least carbon intensive fossil fuel. Without emission restrictions, the share of electricity produced from natural gas reaches a value of only 35% in 2020, compared to 51% in the REFERENCE case. In Germany the phase-out of 21.3 GW of nuclear capacities producing roughly 160 TWh/a takes place in the time periods 2015 and 2020. The missing generation capacity is compensated mainly by new lignite capacities (+11 GW/+86 TWh) in 2015 and +2 GW/+18 TWh in 2020) and new coal capacities (+6 GW/+49 TWh in 2020). The remainder is substituted by new natural gas fired capacities (+8 GW/+32 TWh in 2015 and +4 GW/+7 TWh in 2020). This allows power production in Germany to remain on a much higher level with a corresponding reduction of power imports compared to the REFERENCE scenario.

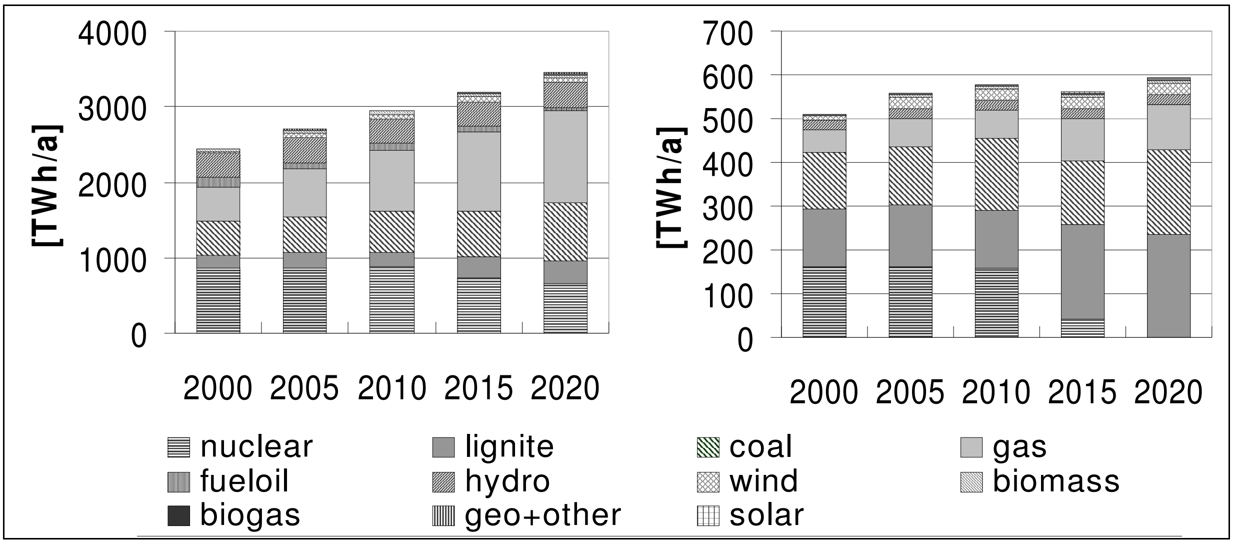

Figure 46: Evolution of the power generation mix in the EU-15 and Germany without CO_2 restrictions (CO_2_UNLIMITED)

The results of the REFERENCE scenario have shown that even under the assumed and comparatively strict CO_2 reduction path renewable electricity production is not an economically attractive option, and that apart from the already installed capacities no significant development of renewables takes place. This very small effect that the CO_2 restrictions have on the additional development of renewable electricity sources can be quantified when comparing their development to that in the CO_2_UNLIMITED scenario. Even in this scenario without emission restrictions the rising fuel prices alone allow the development of a very small amount of low-cost renewable potentials between 2002 and 2020 (+4.3 GW / 18 TWh, mostly from biogas and wind onshore). Thus, when compared to the same period in the REFERENCE scenario, this means a total of only 12 TWh of additional RES-E are used throughout the EU-15 as a result of the CO_2 restrictions introduced.

If no CO_2 restrictions are applied, only 2.5 TWh more renewable electricity from biomass and biogas sources are produced in <u>Germany</u> in 2020 when compared to 2002. With an additional 5 TWh the corresponding increase in the REFERENCE scenario with emission restrictions is only slightly higher.

The unrestricted production factor CO_2 emissions in the scenario CO_2 _UNLIMITED also has effects on the power exchange balances of the modelled regions. Especially countries with a CO_2-intensive power production, and even more so if they also have ambitious emission reduction targets, produce significantly more electricity themselves, which allows to reduce imports. Besides Italy and Spain, Germany is an example for such a country, with the additional challenge to substitute its CO_2-free nuclear power generation. The differences of the power import and export flows between the two scenarios are shown graphically in Figure 47.

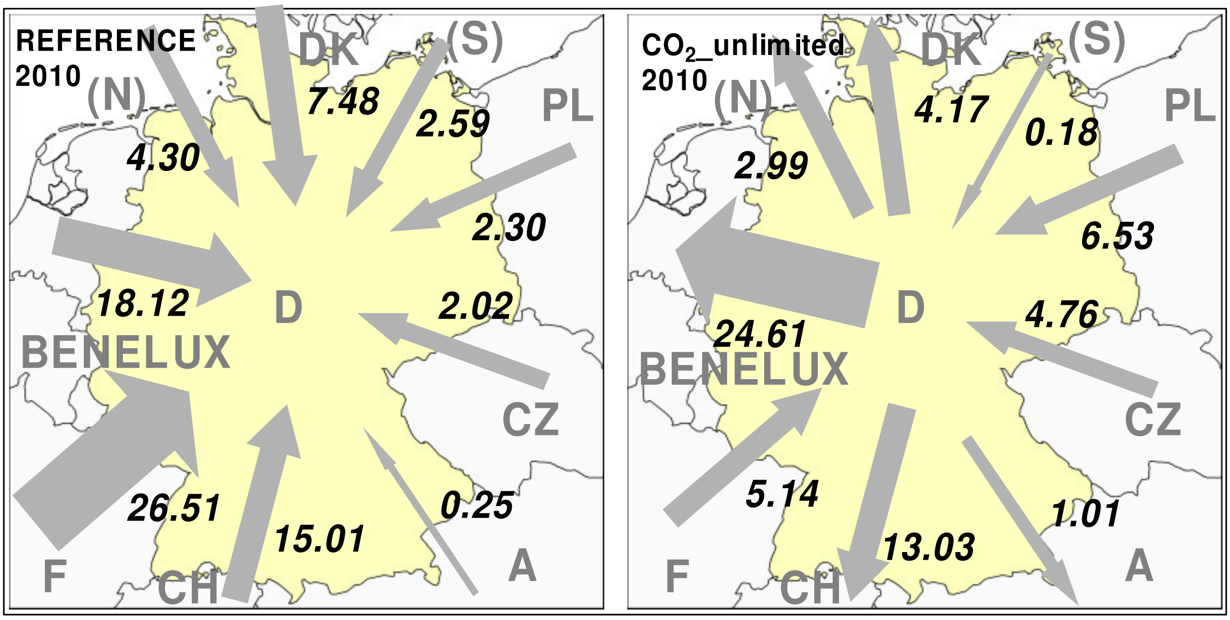

Figure 47: Development of the German electricity exchange balance (CO_2_UNLIMITED vs. REFERENCE)

In contrast to the high imports in the REFERENCE scenario, which reach a total of more than 78 TWh in 2010, Germany would produce power in excess of its own electricity demand in the CO_2 _UNLIMITED scenario, allowing it to export a net total of 29 TWh of electricity in 2010. The largest exports in this case go to the Benelux region and to Switzerland, while imports from France are much lower. After a decrease to less than 4 TWh of exports in 2015 due to the phased out nuclear capacities, the level of exports rises again to 27 TWh in 2020.

Also in France total power production is higher than the domestic demand throughout the whole time horizon, and exports remain at a high level between 70 TWh and 75 TWh until 2010. However, as the construction of new nuclear capacities is not attractive under the unrestricted framework conditions and domestic demand continues to rise, exports are diminished from 2010 onwards and reach a level of 17 TWh in 2020.

Without CO_2 emission limitations in the CO_2_UNLIMITED scenario, the increase of marginal power production costs across the EU-15 is significantly lower than in the REFERENCE case. Instead of an EU-15 average of about 4.3 cent/kWh and a maximum of 5.3 cent/kWh in Spain, which are reached in the 2020 period of the

REFERENCE scenario, the maximum average marginal costs in the 2020 period of the CO_2_UNLIMITED scenario stay below 4.1 cent/kWh at an average of about 3.4 cent/kWh. Also in France and Germany the increase is lower. Beginning with 1.6 cent/kWh in the year 2000, marginal costs in France increase to 3.4 cent/kWh in 2020. Starting at a higher level of 2.0 cent/kWh in the year 2000, the increase in Germany to 3.3 cent/kWh is more moderate than in France. Generally, the increases are partly caused by increasing fuel prices, but also by the growing shortage of power plant capacities, which requires a more frequent operation of the most expensive power plants in the peak load range.

Total emissions in the modelled ETS participant countries diverge significantly in 2020. Instead of a total of about 1,476 Mt of CO_2 in the REFERENCE scenario, 1,798 Mt of CO_2 are emitted in the same period of the CO_2_UNLIMITED scenario. This corresponds to an increase of total CO_2 emissions of almost 22%. With about 3%, the corresponding difference in 2010 is much smaller, as the adaptation of the power plant portfolios to the CO_2 restrictions in the REFERENCE scenario is just about to begin in this period. The largest total differences between the two scenarios occur in Germany and Poland. Without CO_2 restrictions, Germany would emit 140 Mt (65%) more CO_2 in 2010 and 246 Mt (113%) more in 2020. For Poland, the corresponding values are an additional 66 Mt (51%) of CO_2 emissions in 2010 and 108 Mt (167%) more CO_2 in 2020. Only in Belgium, Denmark and Luxemburg the CO_2 emissions do not increase further.

With its generation mix dominated by nuclear power, France shows very low specific emissions at around 55 gCO_2/kWh in the year 2000. Specific emissions increase to 88 gCO_2/kWh due to a slightly increased use of coal from 2005 to 2015, and a moderately increased natural gas use in 2015 and 2020, as well as a lower power production than in the REFERENCE scenario. As German nuclear power production is predominantly replaced by power from lignite in 2015 and further coal and gas capacities are added in 2020, the specific emissions of the German power sector increase notably from slightly above 500 gCO_2/kWh in the year 2000 to 670 gCO_2/kWh in 2020[188]. In the Spanish power sector the already relatively large coal fired capacity share in the year 2000 is further increased throughout the modelled time horizon. This leads to a moderate increase of specific emissions from 408 gCO_2/kWh in the base year 2000 to 477 gCO_2/kWh in 2020. With values above 800 gCO_2/kWh the highest specific emissions occur in Greece and Poland, as there are no incentives to replace inefficient lignite and coal fired plants under these framework conditions.

[188] All figures concerning the specific CO_2 emissions of power generation are related exclusively to the amount of CO_2 released by the power production processes in the model, the emissions related to the coupled processes of heat generation are not included. This leads to lower values than often found in statistics, where heat-related emissions for practical reasons are counted together with those of power generation processes.

9.3.3 Influence of the natural gas price

As shown in the REFERENCE scenario, the construction of natural gas fired power plants is the economically most attractive choice among the available fossil fuel generation technologies in order to fulfil the given obligations for a mitigation of CO_2 emissions. However, this option is also subject to a high uncertainty concerning the price of the primary energy carrier natural gas. This makes the future development of the natural gas price a crucial parameter for the capacity additions and the future composition of the capacity mix. Through a variation of the gas price in this scenario, the influences on the capacity and generation structure of the European electricity sector as well as on the marginal costs of power generation and CO_2 mitigation can be identified[189].

The aim is to assess to what extent a significantly more expensive conventional CO_2 mitigation option makes the use of renewable electricity more attractive, even without incentive mechanisms in place. The gas price developments in the GAS+x scenarios differ from that in the REFERENCE scenario by a gas price markup of x% from 2015 onwards. From 0% in the year 2000, the gas price markup increases linearly up to x% in the year 2015.

In comparison to the REFERENCE scenario, the high increase path of the natural gas price in the GAS+75 scenario is indeed able to trigger an increased use of renewable electricity (cf. Figure 48), especially in Germany and Spain, but also in other EU-15 countries. It is mostly additional wind and biomass potentials, which are realised in 2020 (+170 TWh) as they are the comparatively least expensive ones. To a much smaller extent renewable electricity use is increased already in 2015 (+73 TWh). The 50% gas price increase only leads to a marginally higher utilisation of renewable electricity than in the REFERENCE scenario (+4 TWh in 2015 and +13 TWh in 2020). However, even with the stronger gas price increase of 75%, the additional renewable potentials that become economically attractive until 2020 stay 8 TWh below the amount that would be necessary to reach the 2010 targets of the RES-E Directive. Altogether, natural gas fired electricity production in 2020 decreases by 580 TWh (34%) in the GAS+50 scenario, and by 1062 TWh (63%) in the GAS+75 scenario.

Throughout the EU-15 Member States, but especially in the countries with an extensive use of natural gas and without the possibility to expand nuclear power production (e.g. Germany, Italy and Spain), shares of the otherwise installed natural gas fired capacities and their power production are instead taken over by hard coal based electricity generation. The hard coal fired power generation remaining in 2020 increases from a marginal 5% in the REFERENCE scenario to 13% in the GAS+50

[189] For an analysis of these interdependencies between the European markets for natural gas, electricity and CO_2 certificates the model version PERSEUS-EEM has been developed (cf. [Perlwitz et al. 2005]). This model incorporates a detailed endogenous representation of the supply options for natural gas.

scenario and 20% in the GAS+75 scenario. The use of lignite remains practically unchanged.

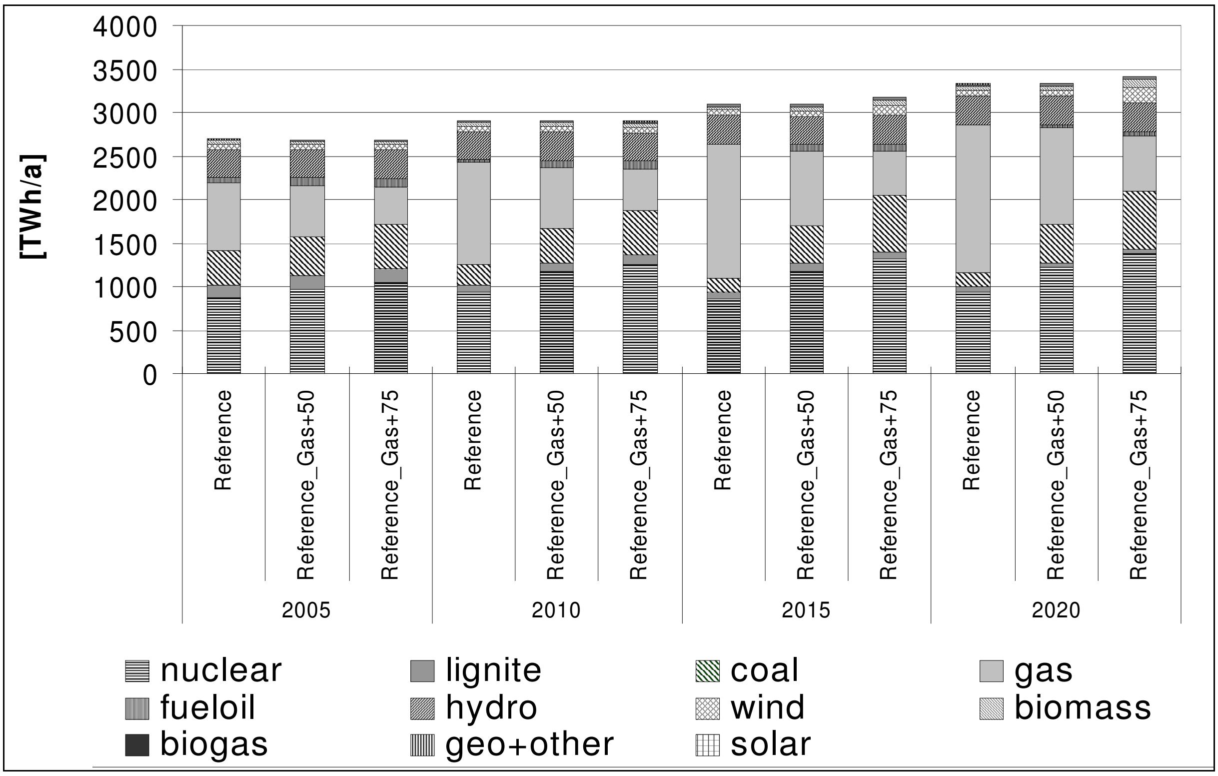

Figure 48: Structure of electricity production in the EU-15 (GAS+50 and GAS+75 vs. REFERENCE)

Moreover, power production from the increasingly expensive primary energy carrier natural gas is limited by more CO_2-free nuclear power generation in Europe from 2010 onwards. The share of nuclear power in the EU-15 generation mix in the year 2020 increases from 28% in the REFERENCE scenario to 37% in the GAS+50 scenario and to 40% in the GAS+75 scenario. New nuclear reactor capacities are constructed in all EU-15 Member States that are allowed to do so, especially in the United Kingdom, where 40 GW are added until 2020 in the case of a 75% increase of the gas price. In France, up to 13.5 GW more nuclear capacities are constructed until 2020, and up to 2.5 GW in Finland under the assumed gas price increase. Also in the new Member States nuclear generation reaches a higher importance in this case, while coal fired generation is increased in those countries that are not allowed to construct new nuclear capacities. Despite the increased economic attractiveness of nuclear power production in the later time periods with higher gas prices and stricter CO_2 limitations the use of the remaining allowed production of nuclear power plants in Germany is not shifted to later periods.

In the GAS+50 scenario, the shifted importance of technologies used for power production only leads to a slight regional dislocation of power production, and a corresponding adjustment of power exchange flows among the regions. Especially in 2020 the higher natural gas prices in the GAS+50 scenarios lead to a shift of power production from countries that rely heavily on natural gas in the REFERENCE scenario, as e.g. Belgium, Denmark and Germany, to regions that can use more nuclear power as Finland, France and the United Kingdom, or coal based power as Spain. In the GAS+75 scenario the above tendencies become more distinct. The only exceptions from this are Germany and the Netherlands. In Germany, the extremely high natural gas price makes not only the continuation of old coal fired capacities attractive, but also the construction of new coal fired capacities from 2015 onwards. Power production from these capacities mainly reduces the import of electricity from natural gas fired power plants in the Netherlands, which are not economic any more at the high costs for the energy carrier. In exchange for the less expensive power production from coal, the German surplus of emission certificates is reduced, so that less certificates can be sold.

Next to the capacity and production mix, also the marginal costs of power generation and of CO_2 mitigation are affected by the increasingly expensive natural gas supply. As natural gas fired power plants under the given CO_2 restrictions are operated not only in the peak load range any more, but also in intermediate load, an increase of the fuel price does directly affect the annual average marginal generation costs. Throughout the EU-15 countries, the average of about 4.3 cent/kWh in the 2020 period of the REFERENCE scenario increases to 5.6 cent/kWh in the GAS+50 scenario, and to 7.9 cent/kWh in the GAS+75 scenario. Moreover, it can be observed that the increase is greater in countries which do not have the option to expand their nuclear power production. In most European countries more than 9 cent/kWh are reached in the 2020 period of the GAS+75 scenario, while marginal generation costs stay below 5 cent/kWh in France, Finland and the United Kingdom. Also countries with significant hydro power generation like Austria and Sweden experience a smaller increase of the average marginal power production costs.

Similarly, the marginal costs of CO_2 reduction increase significantly due to more expensive reduction options that need to be chosen in order to comply with the given emission reduction obligations (see Table 24). While the differences in 2005 are rather small, marginal CO_2 reduction costs in the year 2020 increase up to a maximum of almost 79 €/tCO_2 in the GAS+75 scenario, compared to about 25 €/tCO_2 in the REFERENCE scenario.

Table 24: Marginal costs of CO_2 reduction (GAS+50 and GAS+75 vs. REFERENCE)

	2005-2007 [€/t CO_2]	**2008-2012** [€/t CO_2]	**2013-2017** [€/t CO_2]	**2018-2022** [€/t CO_2]
REFERENCE	9.9	20.4	23.7	25.4
GAS+50	10.7	21.9	31.3	42.2
GAS+75	11.8	29.8	58.8	78.9

9.3.4 Influence of promotion schemes for renewable electricity utilisation

From the results of the previous scenarios it becomes clear that the cost structure of the electricity market, which of the various benefits of renewable electricity use so far only reflects CO_2 mitigation, will not lead to the politically desired increase of their utilisation. Thus, a promotion of renewable electricity use is necessary, even under the advantageous circumstances of strict emission limitations and increasingly expensive natural gas.

Various design options for the promotion of renewable electricity shall be analysed in the following. Again, the focus of the analysis will be on the EU-15 as a whole, but also on relevant exemplary Member States. Three main scenarios are examined in this section, for which the framework conditions of the REFERENCE scenario are amended by promotion instruments for renewable electricity use. This promotion is either realised by specifying mandatory targets for renewable electricity generation or by an integration of financial incentives into the model.

The first scenario consists of two cases, in which the national renewable electricity quotas for 2010 as stipulated in Directive 2001/77/EC need to be fulfilled. In the first case, which is referred to as the TARGETS_2010 case, this is the only stipulation concerning renewable electricity use. Without more ambitious longer term targets, a further increase of the use of renewable electricity in the model regions, i.e. exceeding the quotas specified for 2010, does not happen in this case. For this reason, it is not considered in detail in the following descriptions. Instead, in order to analyse the effects of continued integration efforts for renewable electricity, a longer term target for 2020 is specified in addition in the so called TARGETS_national case. Even if no binding targets have been specified yet for this period[190], as a possible target the amount of 1,166 TWh has been proposed by the European Renewable Energy Council. This stipulation corresponds to a renewable share of primary energy use in electricity generation of approximately 20%, and it is integrated as an ambitious, but feasible long term target into the model. In terms of generated electricity, this means that about one third has to come from renewable sources. The target is specified on the EU-15 level, with the model being able to choose between renewable resources all over the EU-15 for compliance, wherever their utilisation is economically most attractive. Thus, the cost-minimising approach of the model is used to indicate which renewable potentials should be utilised at what time and in which country in order to fulfil this target in a least cost way.

In the second case regarded, which is called the TARGETS_EU scenario, also the 2010 target is specified as a cumulative target on the EU-15 level[191]. Among other

[190] Cf. chapter 3.3. While no binding longer term targets have been specified on a European level, individual Member States already have such targets. An example is the policy target of the German Federal Government, which intends to use at least 20% of renewable electricity in 2020. This would be equivalent to a 4.2% share of primary energy from renewable sources [EEG 2004].

[191] In the scenario TARGETS_EU, a cost-optimised fulfilment is allowed, i.e. only the cumulative EU-15 target, but not the individual Member States' targets have to be fulfilled. This condition is

things, the results of this scenario allow to compare to what extent the national renewable burden sharing targets implemented in Directive 2001/77/EC coincide with the theoretical least cost utilisation of the available resources for renewable electricity generation.

As a third option for the promotion of renewable electricity use, the effects of the financial incentives currently used in the EU-15 Member States with price-based renewable electricity support policies are considered in the so called INCENTIVES scenario.

9.3.4.1 National targets in 2010 plus cumulative EU-wide target in 2020

In this scenario, which is called TARGETS_national, the evolution of the capacity and production mix in the EU-15 clearly reflects the two target years 2010 and 2020 (cf. Figure 49). They are characterised by a notable increase of renewable electricity capacities, totalling 242 GW in 2010 and 373 GW in 2020. Instead of new nuclear capacities constructed in 2020, as observed in the REFERENCE scenario, a continued decline of nuclear power production can be seen here.

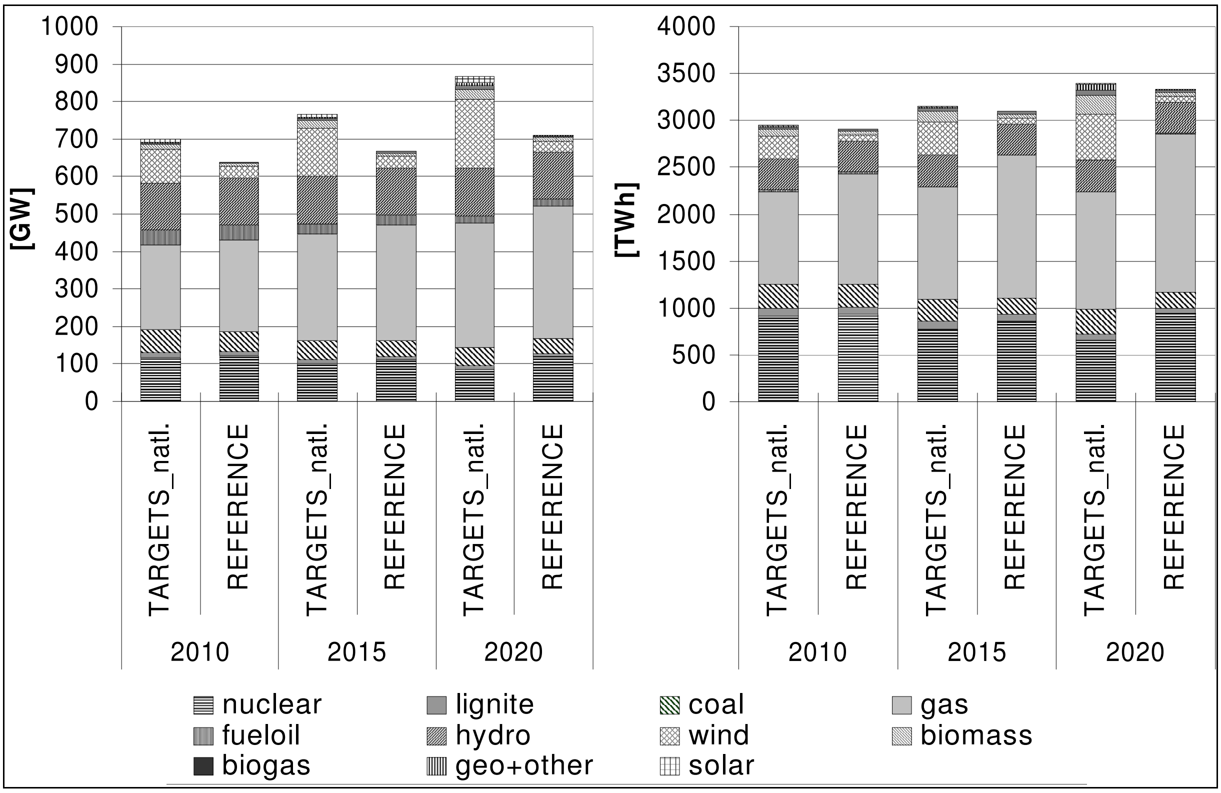

Figure 49: Structure of installed capacities and power production in the EU-15 by energy carrier (TARGETS_national vs. REFERENCE)

With 868 GW the total installed capacity in 2020 in the TARGETS_national scenario lies 158 GW above that in the REFERENCE scenario. A reason for this large

equivalent to a Green Certificate Trading System with perfect foresight and without transaction costs. The same condition is also applied for the indicative 2020 RES-E target.

increase are the comparatively low full-load hours of renewable electricity technologies, and especially those of wind energy conversion.

The evolution of renewable power production is accomplished mainly by the use of wind power resources, both onshore and offshore, as well as renewable biogenic electricity sources (cf. Figure 50). Available wind potentials are realised up to 75% (231 TWh) offshore, and to more than 90% (257 TWh) onshore. Already in 2010 104 TWh or 34% of the available offshore wind resources are utilised, and 133 TWh or 50% of the available onshore wind energy resources. Concerning biogas, the corresponding utilisation rates are 72% (51 TWh) in 2020 and 23 TWh in 2010. Solid biomass potentials are realised to a maximum of almost 88% (175 TWh) in 2020 and 66 TWh in 2010. The biodegradable fraction of municipal solid waste is exploited to more than 90% (23 TWh) in 2020 and 15 TWh in 2010.

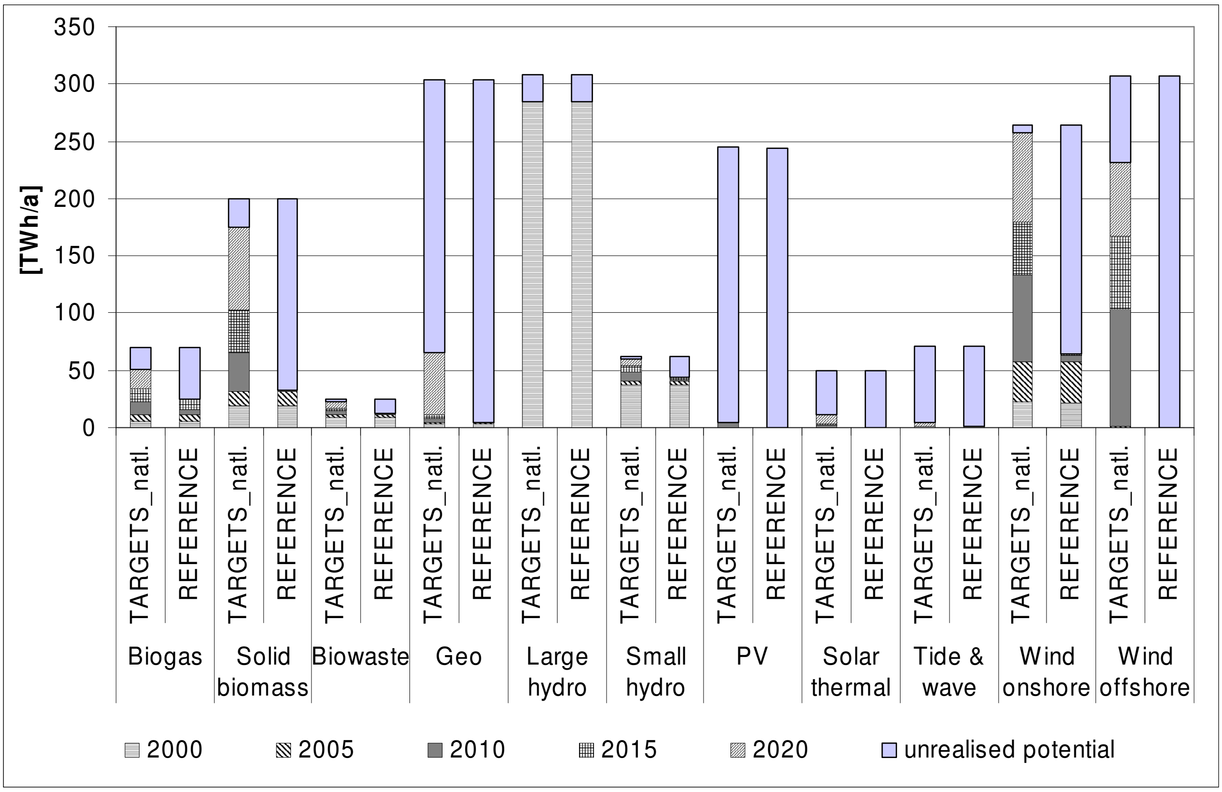

Figure 50: Evolution of renewable elecricity generation in the EU-15 by energy carrier (TARGETS_national vs. REFERENCE)

Reaching a total electricity production of 60 TWh in 2020, nearly the entire remaining small hydro potential is also developed continuously throughout the modelled time horizon. On the other hand, the assumed large available geothermal resources are only scarcely realised (65 TWh), primarily in the 2020 period. Solar potentials remain virtually untapped, with 5 TWh of PV and 11 TWh of solar thermal electricity generated in 2020. Furthermore, no additional large hydro capacities are built. Compared to the REFERENCE scenario it is mostly electricity from natural gas fired (-443 TWh) and nuclear power plants (-22 TWh) which is replaced by renewables at the end of the time horizon, while the production of electricity from hard coal is slightly higher (+89 TWh). In 2010 the corresponding values are a replacement of 200 TWh from natural gas and 22 TWh from nuclear energy, while an additional 11 TWh from coal are produced. The large untapped part of the geothermal potential is mainly made up by the German HDR potential, which is not used due to the comparatively high production costs. However, 3 TWh from this source are produced in Germany in 2010 and 58 TWh in 2020, which is in the same order of magnitude as offshore wind power production in Germany. With 7.8 GW the installed capacities necessary to reach this production in 2020 are much smaller than for offshore wind energy conversion (16.7 GW), which is due to the high full load hours of geothermal electricity generating units.

In Germany significantly more renewable capacities are installed in the TARGETS_national scenario, leading to a total installed capacity of 67 GW in 2020, compared to a stagnating renewable capacity of 26 GW in the last period of the REFERENCE scenario (cf. Figure 51). The results with an extremely steep increase of installed wind capacities reaching 25 GW onshore and 16 GW offshore in 2020 indicate that within the potentials for renewable electricity generation available across the EU-15, German on- and offshore wind energy potentials are comparatively attractive and contribute substantially to the compliance with the overall European renewable electricity target in 2020 (50 TWh onshore and 58 TWh offshore). Already in 2010 wind energy capacities in Germany contribute with 28 TWh onshore and 23 TWh offshore or a total of 75% of the renewable electricity production necessary to comply with the national renewable electricity target.

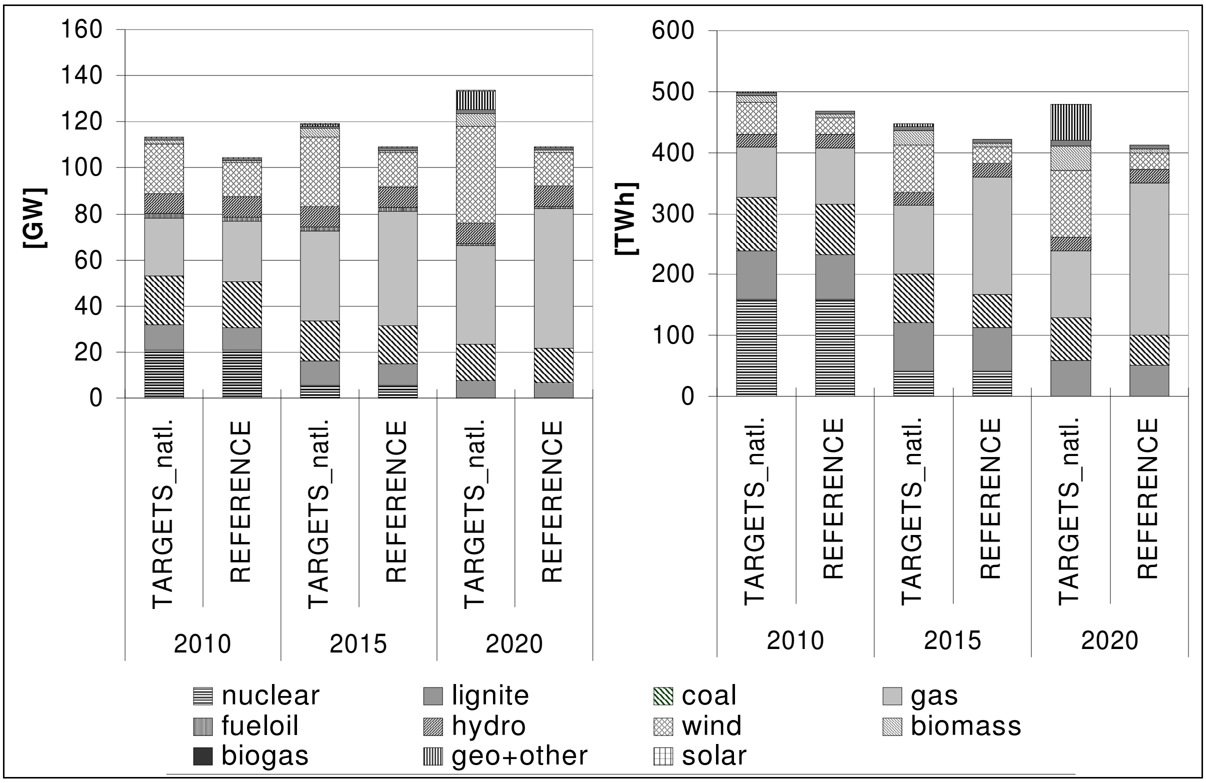

Figure 51: Structure of installed capacities and power production in Germany by energy carrier (TARGETS_national vs. REFERENCE)

As a further difference compared to the REFERENCE scenario, power production from 2010 onwards remains on a higher level also in later periods (+31 TWh in 2010 up to +66 TWh in 2020), which mitigates the amount of imports necessary mainly as a consequence of the nuclear phase-out. The mandatory use of renewable electricity leads to a significantly reduced power production from the most expensive natural gas fired capacities. Instead of 251 TWh in the REFERENCE scenario, only 110 TWh of gas fired electricity are produced in 2020. Already in 2010, only 83 TWh of electicity instead of 93 TWh are produced from natural gas. Moreover, the increased indigenous production of CO_2-free renewable electricity in comparison to the REFERENCE case allows to use more emission rights through a slightly increased power production from hard coal (+4 TWh in 2010 and +21 TWh in 2020) as well as from lignite (+8 TWh in 2010 and +6 TWh in 2020).

Figure 52 gives a more detailed overview of the temporal evolution of the utilisation of renewable electricity potentials in Germany. As mentioned above, on- and offshore wind energy resources are used most intensively. In total, the available resources are exploited up to 50 TWh (100%) onshore and 59 TWh (69%) offshore, respectively.

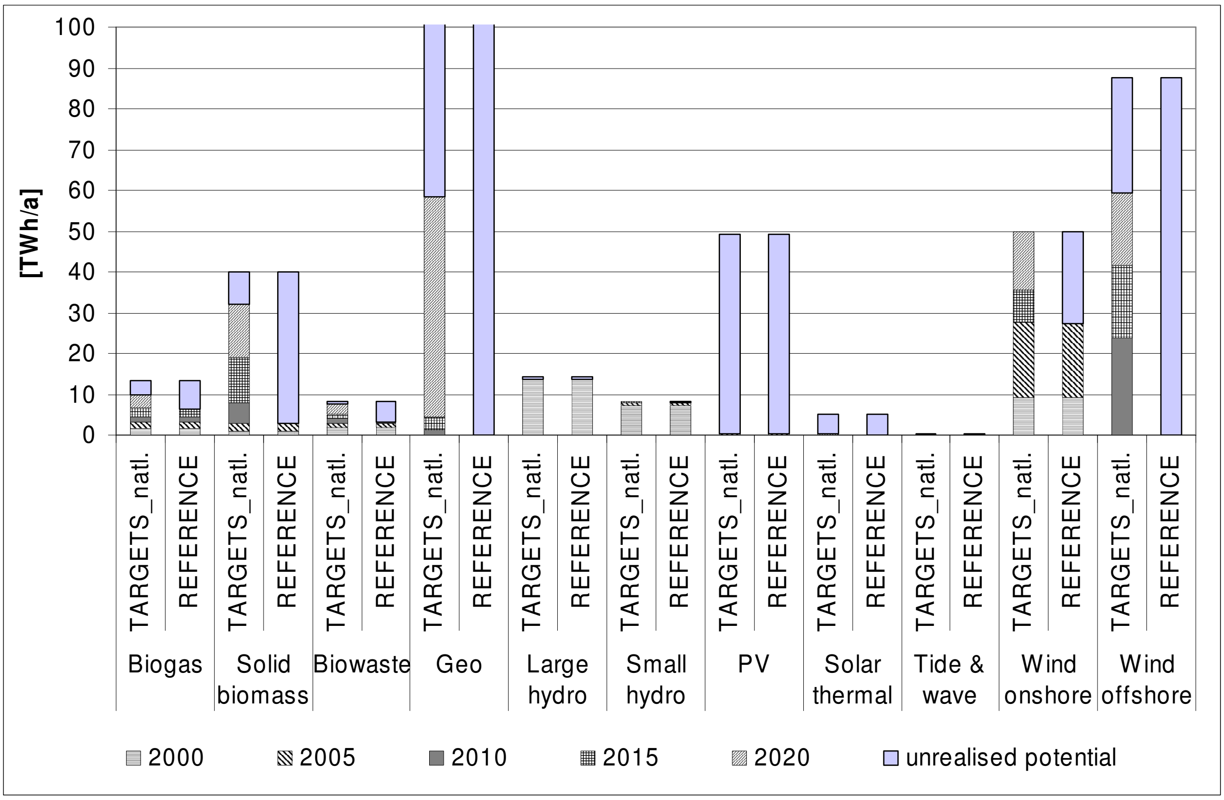

Figure 52: Evolution of renewable elecricity generation in Germany by energy carrier (TARGETS_national vs. REFERENCE)

Next to wind energy, the use of biogenic sources contributes most to the overall renewable electricity share. More than 70% of the available mid-term biogas potentials are realised (almost 10 TWh), while about 80% (32 TWh) of the solid biomass resources are utilised, along with 90% (7.5 TWh) of the available biowaste resources. Of the geothermal potential, including hot dry rock installations, 58 TWh are utilised by 2020, assuming that the technological barriers can be overcome to the degree necessary to achieve this production level. The rest of the huge potential remains untapped. Photovoltaic and solar thermal potentials are not realised due to their very high costs in comparison to the other available renewable options.

The case of Germany in 2020 illustrates that, although not yet competitive, the use of renewable electricity is more attractive for countries with a CO_2 intensive power production. In this case, the costs of renewable electricity generation are lowered due to the saved emission rights and a positive impact on the power exchange balance.

Different from Germany, France can fulfil its CO_2 target rather easily by using nuclear power, but it does also possess relatively inexpensive RES-E sources. In Figure 53 the evolution of the capacity and production mix in France are illustrated. The 2010 national target of a 21% share of renewable electricity, and also the contribution to the cumulative European target in 2020, is realised mainly by building wind farms (totalling 10 GW in 2010 and 29 GW in 2020), but also some biomass (1.5 GW and 5.2 GW in 2010 and 2020, respectively) and biogas facilities (0.5 GW in 2010, 1.9 GW in 2020).

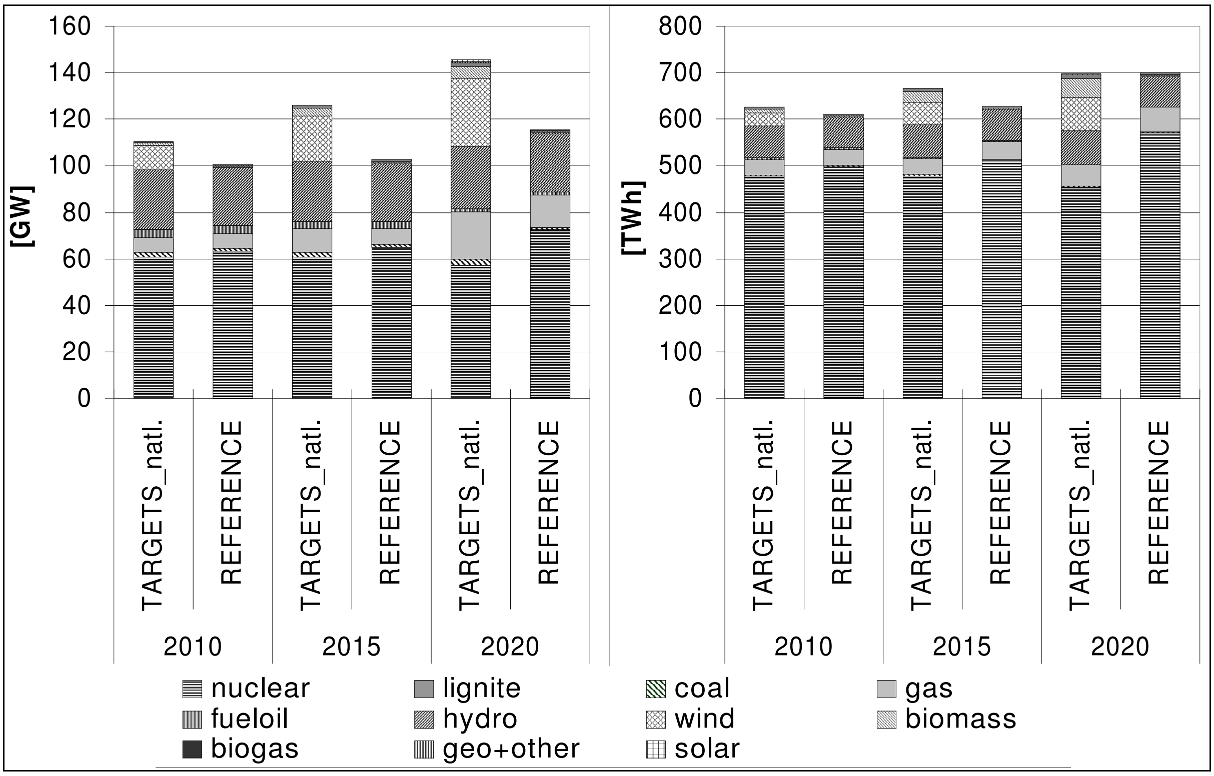

Figure 53: Structure of installed capacities and power production in France by energy carrier (TARGETS_national vs. REFERENCE)

Along with on- and offshore wind power dominating both additional capacity and production of the additional RES-E capacities realised as a contribution to the 2020 target, also more natural gas installations are commissioned from 2015, reaching a total of 20.5 GW of installed capacity in 2020. In the power plant mix dominated by nuclear power with poor load following characteristics this increase is mainly needed to provide tertiary reserves necessary for the significant wind power development.

The development of the individual renewable energy sources and their contributions to the national and the cumulative European target can be found in Figure 54. It can be seen that also solid biomass (7.5 TWh / 37.2 TWh in 2010 / 2020), small hydro power (9 TWh / 12 TWh), and biogas (2.5 TWh / 7.8 TWh) contribute significantly to the French RES-E production. The small hydro power potential (12 TWh) is fully realised under these circumstances, while the available biogas and solid biomass resources are realised to about 65% (10 TWh) and 79% (38 TWh) by the end of the modelled time horizon. The much smaller potential of biowaste is realised to almost 50% already in 2010 (1.7 TWh) and to over 80% (2.9 TWh) until 2020. At the same time, there is no development of additional potentials of large hydro power, while wave and tide installations contribute a marginal 0.4 TWh until 2020. The photovoltaic potentials remain completely untapped under both target conditions, due to their very high costs. For similar reasons, only 1 TWh of electricity is produced from solar thermal energy by 2020.

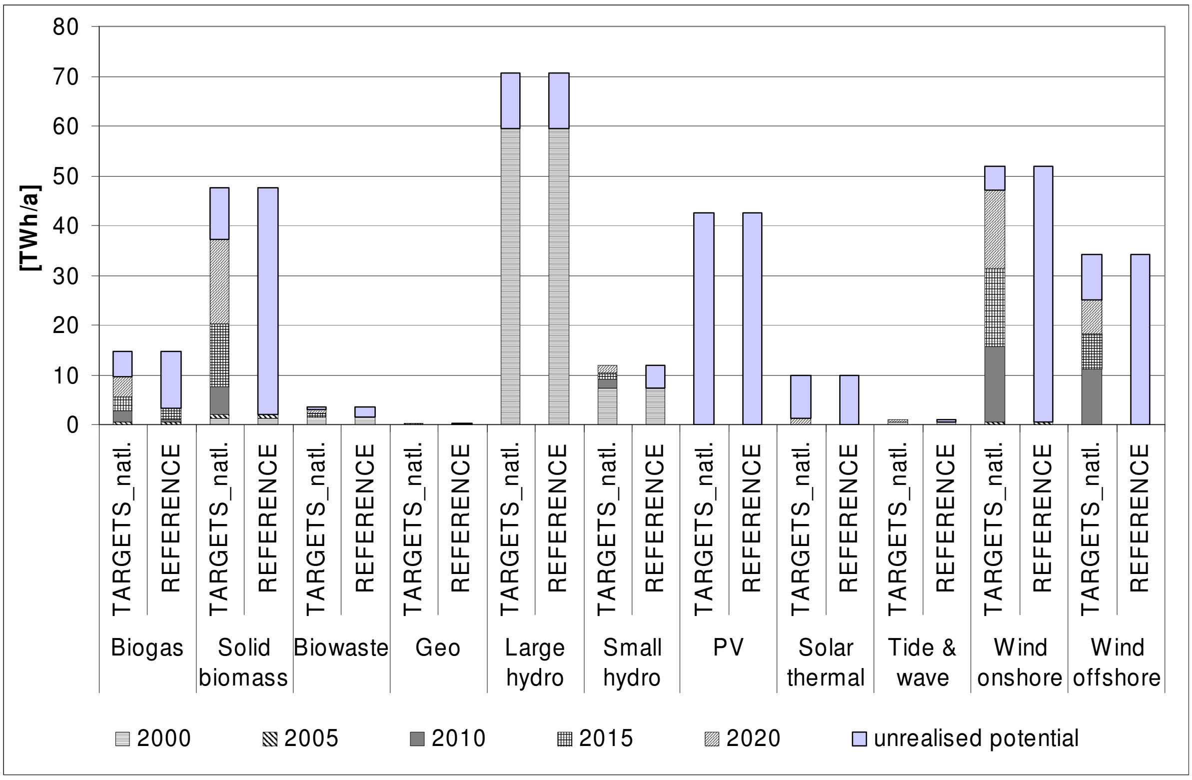

Figure 54: Evolution of renewable elecricity generation in France by energy carrier (TARGETS_national vs. REFERENCE)

It is interesting to note that in 2020 the level of power production in France remains practically unchanged compared to the REFERENCE scenario. The increase of nuclear capacities and production in 2020, which is observed in the REFERENCE case, is entirely substituted by the utilisation of renewable electricity in the TARGETS_national scenario. With 460 TWh of nuclear power production in 2020, the contribution of this energy carrier and also the remaining nuclear capacities are in fact reduced below the level of 2015 in this scenario.

Similar to Germany, the electricity sector in Spain is dominated by fossil fuels. An important difference, however, are the limited possibilities for power imports to Spain. Thus, the growing demand has to be satisfied mainly by indigenous power production. Under the given emission allowance restrictions, this fact induces a massive growth of natural gas fired electricity generation with low carbon emissions in the REFERENCE scenario. When targets for renewable electricity are specified, a large share of this gas fired generation is substituted (see Figure 55).

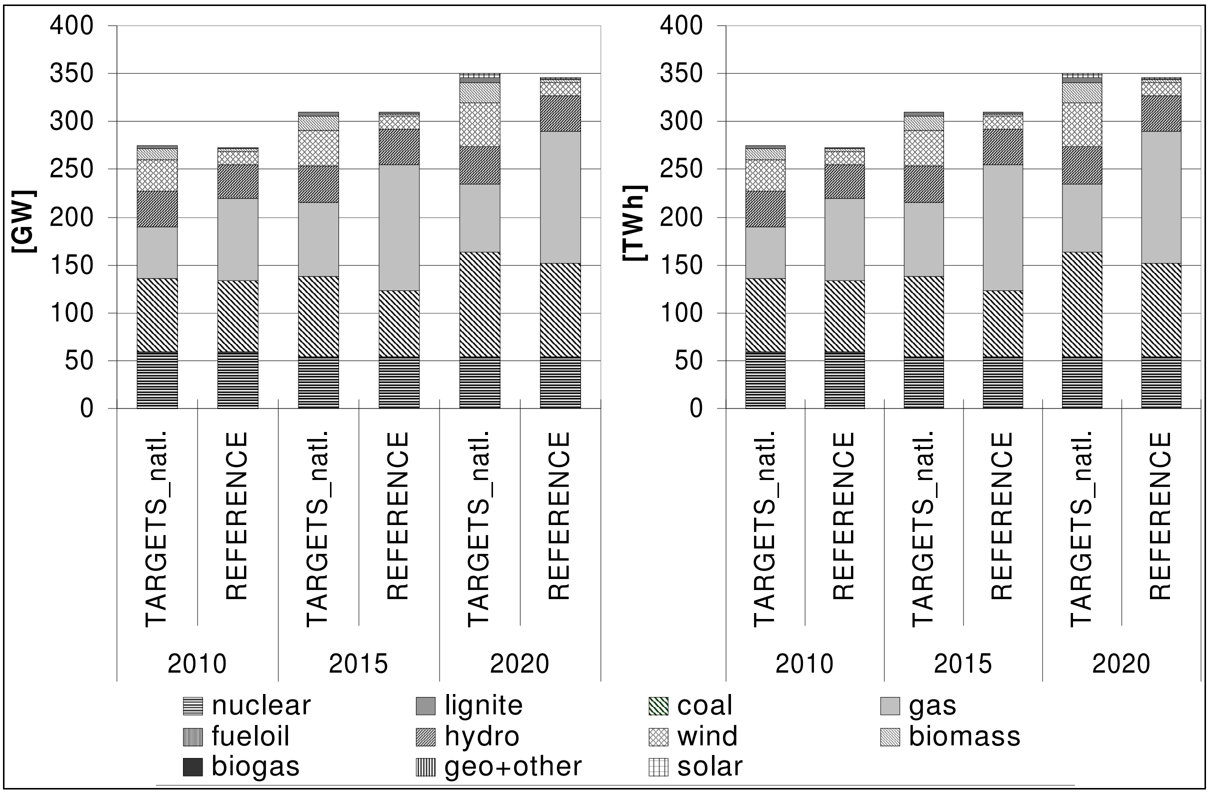

Figure 55: Structure of installed capacities and power production in Spain by energy carrier (TARGETS_national vs. REFERENCE)

In Figure 56 the temporal evolution of renewable electricity use in Spain is shown in more detail. The energy carriers that contribute mostly to the fulfilment of the 2010 target are onshore wind energy with 10.9 GW and a production of 24.8 TWh, offshore wind energy with 2.4 GW of installed capacities and 8.0 TWh produced, as well as solid biomass with 10.7 TWh produced by 1.4 GW of installed capacities. To a lesser extent also biogas (with 0.5 GW and 2.7 TWh) and small hydro power (2.9 GW and 7.4 TWh) are used. Further, the model results indicate that for a cost-optimised fulfilment of the ambitious Europe wide target in 2020 the remaining available potentials of onshore wind, solid biomass, biowaste and small hydro power in Spain should be completely utilised until the end of the modelled time horizon. Further, significant parts of the offshore wind potential (up to 15.8 TWh) are realised in this case, along with further electricity production from biogas (up to 4.9 TWh) and also solar thermal generation (up to 4.8 TWh) from 2015 onwards. Altogether, the total renewable power production of 84.5 TWh in 2010 helps to replace 30.5 TWh of natural gas fired generation and 2.7 TWh of imports. In 2020, the total renewable electricity generation reaches 116.1 TWh, which allows to substitute 5.2 TWh of electricity imports and 68.0 TWh of natural gas fired generation. Moreover coal fired generation can be increased by 1.3 TWh in 2010 and 12.2 TWh in 2020. The capacities and the production of the installed nuclear capacities in Spain is not affected at all by the increased renewable electricity share.

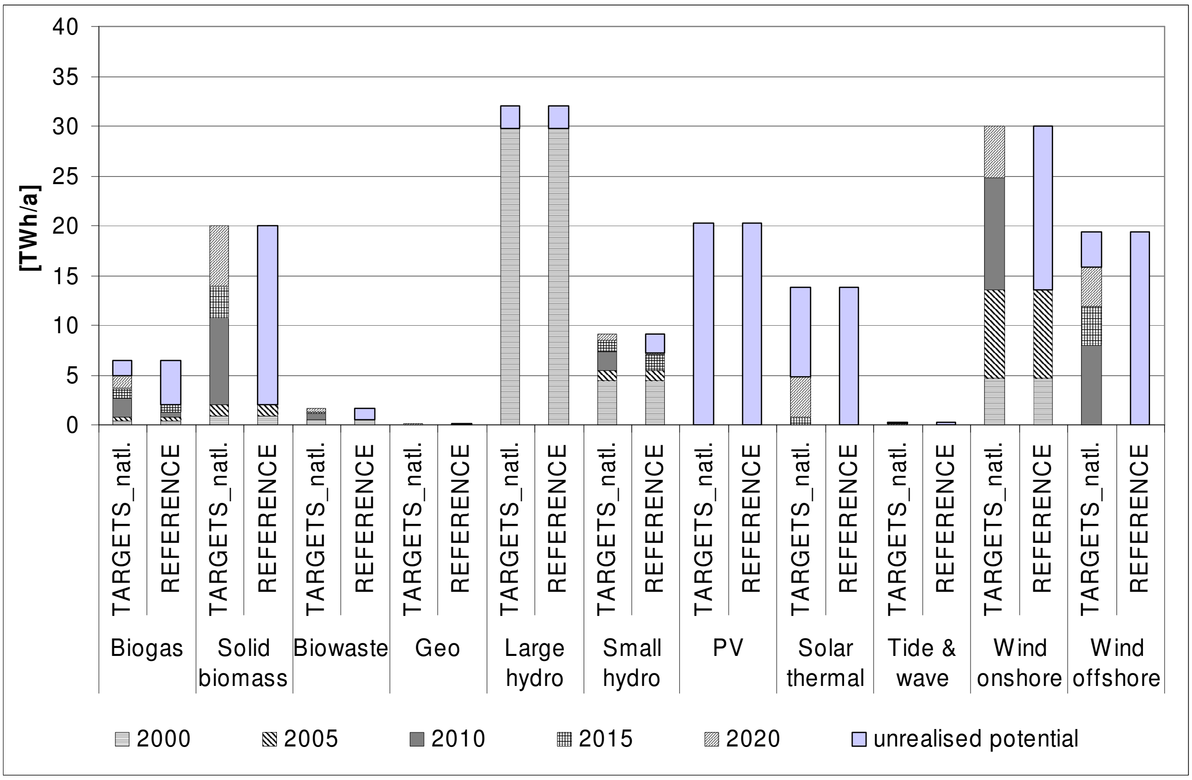

Figure 56: Evolution of renewable elecricity generation in Spain by energy carrier (TARGETS_national vs. REFERENCE)

When looking at the interregional power exchange flows in the TARGETS_national scenario, it can generally be observed that the use of CO_2-free renewable electricity lessens the power imports of countries with a CO_2 intensive electricity sector. Especially in Germany this difference is very high. With imports of about 81 TWh in 2020, 67 TWh less are imported by Germany when compared to the REFERENCE scenario in this period, corresponding to a cut in imports of about 45%. Already in 2010 the difference of the electricity exchange balances is greater than 31 TWh, equivalent to a 40% reduction of electricity imports. In Figure 59 on p. 190 a more detailed overview of the German power exchange with its neighbouring regions in the 2010 period of the TARGETS_national scenario is given, and also a comparison with those in the INCENTIVES scenario. In comparison to the REFERENCE scenario, the French power exchange balance in the TARGETS_national scenario is characterised by higher exports in 2010 (almost 97 TWh instead of 88 TWh) and 2015 (88.4 TWh instead of 54.4 TWh). In 2020, however, French power exports (61 TWh) are almost the same as in the REFERENCE scenario (63 TWh). The decline of French power exports in 2020 in relation to the earlier periods is partly due to the increased German CO_2 free renewable power production, which enables Germany to reduce its electricity imports significantly. Generally, the volume of power imports from regions outside of the EU-15 decreases in 2020 due to the mandatory CO_2-free renewable electricity generation.

The additional use of renewable electricity does have a notable effect on the emissions in countries with an otherwise CO_2-intensive power sector, as e.g. Germany and Spain. Here, emissions can be significantly reduced (-9% in 2020, both in Germany and Spain, -9% in Italy in 2010), which has a positive impact on the emission balances of these countries. Together with Italy, Spain is one of the two most important purchasers of emission allowances. In the REFERENCE scenario, the Spanish power sector requires additional certificates for 43.2 $MtCO_2$ in the year 2010. In 2020 this requirement amounts to 65.7 $MtCO_2$. The introduction of renewable electricity allows to reduce the according amounts of purchased emission rights to 33.9 $MtCO_2$ in 2010 and 51.9 $MtCO_2$ in 2020. This positive impact of renewable electricity use on the emission trading balance in turn allows to continue the existing coal fired generation on a higher level and also to install a higher capacity of new and more efficient coal fired power plants from 2015 onwards.

Contrary to that, emissions in France do not change notably, which is due to the fact that mainly nuclear power production, i.e. another CO_2-free technology, is replaced by RES-E. The emission reductions achieved by the use of renewable electricity replace the most efficient conventional emission reduction measures within the ETS participant countries chosen in the REFERENCE scenario. In particular, this is the construction of nuclear capacities in Poland in 2015 and 2020. In the TARGETS_national scenario, this expansion is reduced by 80% to 2.6 GW. Instead, new natural gas fired capacities are added, and the use of existing coal and lignite fired capacities is continued on a higher level.

For a quantification of the cost effects, including the total and specific additional costs incurred by the use of renewable electricity sources to fulfil the given targets, please refer to section 9.3.4.4.

9.3.4.2 EU-wide targets in 2010 and in 2020

The framework conditions for this scenario, which is called TARGETS_EU in the following, are basically the same as for the TARGETS_national scenario above. As the only difference, a more open restriction considering the achievement of the RES-E targets in 2010 is implemented. Instead of stipulating individually for each country that its renewable electricity target needs to be fulfilled, it is allowed in this scenario that the cumulative sum of the targets for the individual EU-15 Member States is reached, without specifying where this needs to happen. This framework condition enables the model to choose the cost-optimised solution of reaching the cumulative

European RES-E target by utilising the most cost efficient potentials on a European scale, instead of having to resort to probably more costly potentials in individual countries. Apart from predicting the situation in a possible future green certificate trading scheme, the results of this scenario can also give an indication whether the national RES-E targets for 2010 have been chosen in a way that prevents economic inefficiencies, which can occur if more expensive potentials have to be chosen in individual countries, while less expensive potentials in other countries remain unused. This alternative specification of the target fulfilment leads to a similar general development of the electricity sector as in the TARGETS_national scenario. Thus, the following description will only highlight the main differences between the two design options.

More renewable electricity potentials are realised in the 2010 period of the TARGETS_national scenario than in the TARGETS_EU scenario. Under the given restriction of the expansion rate of the potentials, it is advantageous for the fulfilment of the 2020 renewable targets to develop comparatively large and cheap renewable potentials already earlier and in excess of the sum of the national targets. This happens primarily in those countries, which in the TARGETS_EU scenario also realise a much greater share of the 2010 target, namely Germany and the United Kingdom.

Alternatively, only the fulfilment of the 2010 national targets, without the obligation to fulfil the 2020 targets, can be stipulated. This case is designated as the TARGETS_2010 scenario in Table 25. The difference between the amounts of renewable electricity production realised in this case and those in the TARGETS_EU scenario shown in the third column of the table can be interpreted as the green certificate trade balance that would occur under a uniform European green certificate trading scheme in 2010. According to this balance, it becomes obvious that Germany and the United Kingdom, which possess distinctly more inexpensive potentials than necessary to fulfil their 2010 targets, would be able to sell high amounts of green certificates. On the other hand, Italy and Spain would contribute less to a cumulative European renewable electricity target and instead buy green certificates. This is also in line with the difference found between the amounts of renewable electricity realised in the 2010 periods of the TARGETS_national scenario versus those in the TARGETS_EU scenario described above.

The development of marginal costs determined for the TARGETS_national case is hardly affected by the temporal and spatial relocation of RES-E use in the TARGETS_EU scenario. Along with a comparison to the other design options for renewable electricity promotion, the total and specific additional costs incurred by the use of renewable electricity sources to fulfil the given targets in the TARGETS_EU scenario are given in section 9.3.4.4.

Table 25: Renewable electricity generation in the EU-15 Member States for different renewable electricity target specifications

Country	2010 RES-E production [TWh]				2020 RES-E production [TWh]
	TARGETS_national	*TARGETS_2010*	*TARGETS_EU*	*TARGETS_EU – TARGETS_2010*	*TARGETS_EU*
AT	49.3	49.3	46.5	-2.8	58.3
BE	6.2	6.2	4.2	-2.0	13.4
DK	13.2	10.9	16.3	5.4	29.9
FI	29.4	29.4	30.6	1.2	44.7
FR	107.9	107.9	102.6	-5.3	190.7
DE	91.0	68.2	104.5	36.3	253.6
GR	13.3	13.3	9.8	-3.5	20.1
IE	9.3	4.3	9.4	5.1	23.0
IT	99.5	99.5	72.1	-27.4	112.5
LU	0.4	0.3	0.4	0.1	0.9
NL	12.4	12.4	14.4	2.0	33.3
PT	21.4	20.8	22.7	1.9	34.0
ES	84.5	84.5	69.7	-14.8	115.8
SE	93.8	93.8	83.2	-10.6	105.5
UK	57.6	45.1	59.5	14.4	130.3
EU-15	***689.3***	***645.9***	***645.9***	***0.0***	***1166.0***

9.3.4.3 Financial incentives

For the analysis of the INCENTIVES scenario, the REFERENCE scenario is amended to take into account the more attractive financial conditions for the use of renewable electricity potentials when feed-in tariffs or other financial incentives are granted. No mandatory targets for the use of renewable electricity are specified, except for those countries that have quota-based promotion schemes instead of price-based schemes for renewable electricity[192].

In Figure 57 the development of capacities and power production in the EU-15 is shown. More specifically, the temporal evolution of the use of renewable potentials in the EU-15 can be derived from Figure 58. Until 2010 the financial incentives provided

[192] For an overview over the incentive schemes for renewable electricity use in the EU-15 Member States and the implementation in the PERSEUS-RES-E model, please refer to Chapter 3.5 and Chapter 8.6.2.

in most countries induce a significant growth of RES-E use, comparable to that in the TARGETS_national and TARGETS_EU scenarios.

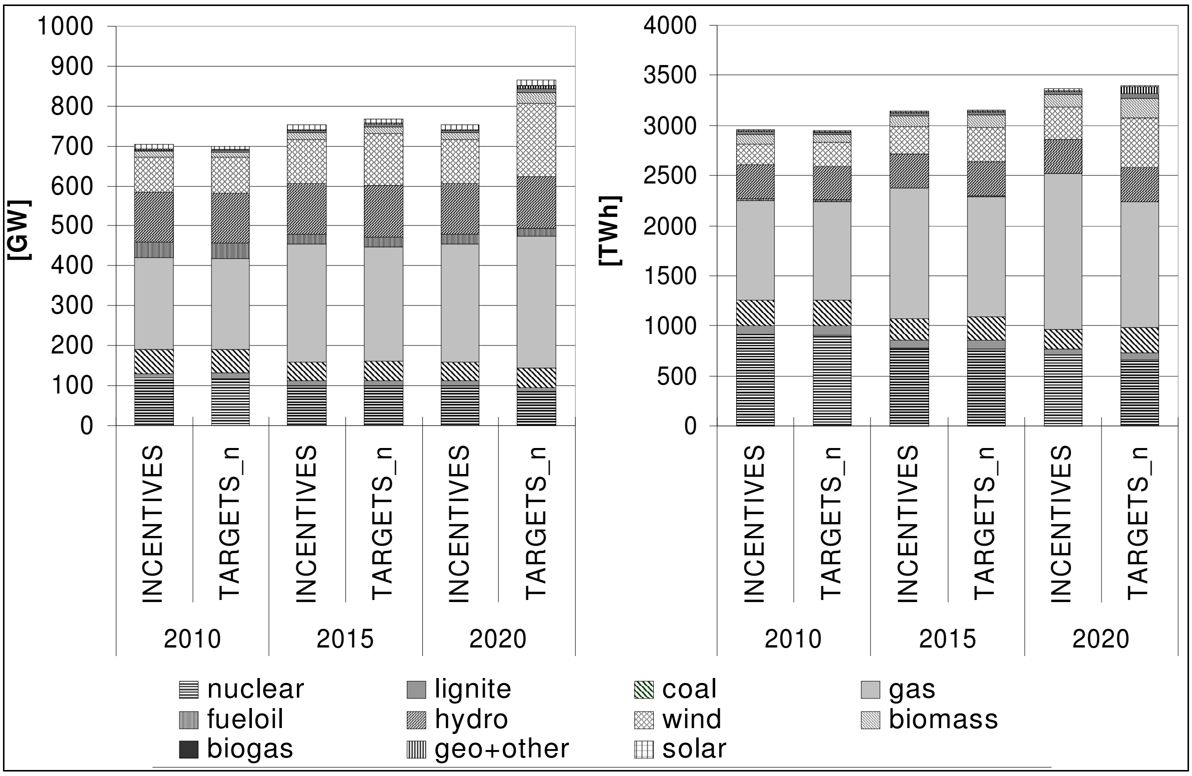

Figure 57: Structure of installed capacities and power production in the EU-15 by energy carrier (INCENTIVES vs. TARGETS_national)

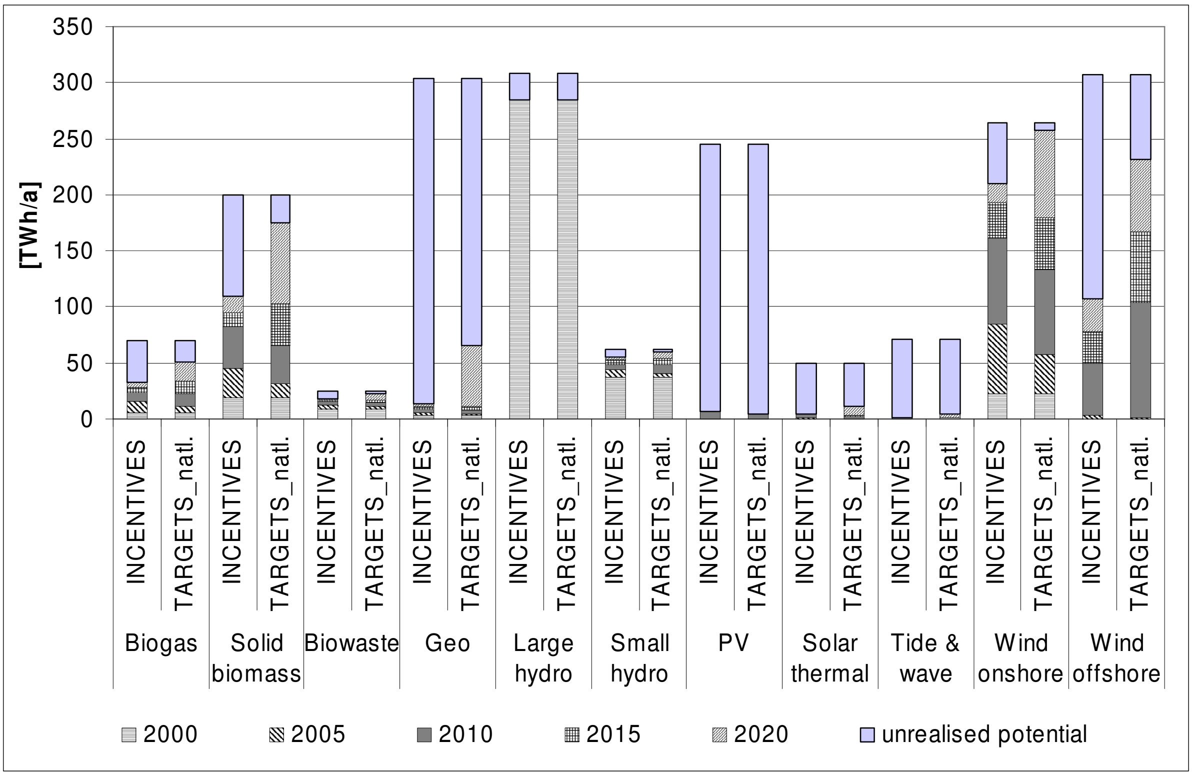

Figure 58: Comparison of the evolution of renewable elecricity generation in the EU-15 by energy carrier (INCENTIVES vs. TARGETS_national)

Based exclusively on their financial viability under the idealised conditions of the model, i.e. without taking profitability margins or other possibly limiting factors into account, a renewable electricity production of 686 TWh is achieved in the 2010 period of the INCENTIVES scenario. This amount is only very slightly below the required 689 TWh that are indicated as necessary for a least cost complicance with the 2010 national targets and the 2020 EU-wide targets in the TARGETS_national scenario. At the same time, the achieved renewable generation in the INCENTIVES scenario is above the summarised renewable generation of 645 TWh in the TARGETS_EU and the TARGETS_2010 scenarios, which directly corresponds to the stipulations of the RES-E Directive. Thus, when only regarding the 2010 RES-E targets as binding, the targets of the RES-E Directive are slightly overachieved for the EU-15 as a whole. Nevertheless it has to be kept in mind that this result of the INCENTIVES scenario is calculated under the premise that the quota-based systems in the countries using them will be completely successful in reaching the respective targets in these countries. In Figure 58 the compliance of all EU-15 Member States with the targets of the RES-E Directive as well as with the cost-optimised renewable electricity use determined in the TARGETS_national and TARGETS_EU scenarios are listed in detail.

Especially in Germany the high level of feed-in tariffs allows a distinctly better compliance than in other countries. Although the financial incentives contribute to a continued increase of renewable electricity use in 2015 and 2020, the target specified for 2020 is not reached. Instead, only about 842 TWh are produced in this case, or 72% of the necessary amount to fulfil the cumulative target in 2020. However, it needs to be taken into account that no country-specific quotas beyond the year 2010 have been specified so far, and only the quotas for 2010 are specified in the model for those countries using a quota-based promotion scheme.

Also concerning the renewable technology shares achieved in the EU-15 in the 2010 period of the INCENTIVES scenario, these do not differ significantly from those in the TARGETS_national scenario. About 26 TWh less electricity from wind energy is produced, but almost 17 TWh more from biogas. Also solar thermal and photovoltaic electricity production is increased by almost 4 TWh, while 1 TWh of each biogas and geothermal resources become viable. On the conventional side, slightly more electricity from natural gas (+14.5 TWh) and nuclear power plants is produced, but less from lignite (-6.8 TWh).

Due to the lower installed CO_2-free renewable production in 2020, the use of the comparatively cheap, but CO_2-intensive fuels coal and lignite is cut by 69.2 TWh and 10.7 TWh, respectively. Instead, natural gas fired and nuclear power production are stepped up by 309.2 TWh and 53.9 TWh, respectively.

In 2020, especially the offshore wind energy potentials are realised to a smaller extent. Only 107 TWh or 35% of the available potentials are realised instead of 231 TWh or 75% in the TARGETS_national scenario. The remaining differences to the renewable electricity production in the TARGETS_national scenario mainly result from a lower electricity production from wind onshore resources (47 TWh less), from solid biomass (65 TWh less), and from biogas (18 TWh less).

Table 26: Renewable electricity production in the EU-15 (INCENTIVES vs. TARGETS_national and TARGETS_EU)

Country	2010 RES-E production [TWh]					2020 RES-E production [TWh]			
	TARGETS_2010	TARGETS_national	INCENTIVES	INCENTIVES - TARGETS_2010	INCENTIVES - TARGETS_national	TARGETS_EU	TARGETS_national	INCENTIVES	INCENTIVES – TARGETS_EU
AT	49.3	49.3	50.8	1.5	1.5	58.3	59.0	57.5	-0.8
BE	6.2	6.2	6.2	0.0	0.0	13.4	13.6	5.4	-8.0
DK	10.9	13.2	12.4	1.5	-0.8	29.9	27.3	13.3	-16.3
FI	29.4	29.4	31.0	1.6	1.6	44.7	43.5	37.7	-7.0
FR	107.9	107.9	104.1	-3.8	-3.8	190.7	195.8	144.7	-46.0
DE	68.2	91.0	112.3	44.1	21.3	253.5	240.2	176.2	-77.3
GR	13.3	13.3	12.1	-1.2	-1.2	20.1	21.4	18.3	-1.8
IE	4.3	9.3	4.3	0.0	-5.0	23.0	23.0	4.4	-18.6
IT	99.5	99.5	99.5	0.0	0.0	112.5	120.5	97.4	-15.1
LU	0.3	0.4	0.3	0.0	-0.1	0.9	0.9	0.3	-0.6
NL	12.4	12.4	15.1	2.7	2.7	33.3	31.3	27.3	-6.0
PT	20.8	21.4	18.1	-2.7	-3.3	34.0	34.0	22.4	-11.6
ES	84.5	84.5	81.3	-3.2	-3.2	115.8	116.3	101.2	-14.6
SE	93.8	93.8	93.8	0.0	0.0	105.5	111.0	90.5	-15.0
UK	45.1	57.6	45.1	0.0	-12.5	130.3	128.5	44.8	-85.5
EU-15	***645.9***	***689.3***	***686.2***	***40.3***	***-3.1***	***1166.0***	***1166.3***	***841.7***	***-324.3***

As the countries with a quota system only have to fulfil their 2010 quotas and do not realise further renewables beyond these quotas after 2010, their contribution is much lower than in the scenarios with a combined European target in 2020. The additional RES-E production induced by the financial incentives in the other countries does not compensate for that. In the following, the situation in Germany, France and Spain shall be examined a bit more closely.

Especially in Germany the comparatively high feed-in tariffs induce a dynamic development of renewable electricity production. In 2010 the achieved share is significantly higher than necessary according to the national target or the contribution to a European target. Renewable electricity production in 2010 is about 21 TWh higher than the cost-minimised solution in the TARGETS_national case requires and even 44 TWh higher than necessary to achieve only the 2010 targets. Thus, more conventional power production is replaced by renewables. Compared to the TARGETS_national scenario the additionally replaced conventional electricity is mostly electricity from lignite (7 TWh) and much less from coal (1.4 TWh), while the largest share of displaced electricity are imports (13.6 TWh).

The additional renewable power production realised in 2010 compared to the same period of the the TARGETS_national scenario originates mainly from biomass (9.6 TWh) and from wind power (8.0 TWh). While the feed-in tariffs allow an increase of the onshore wind power production by 13 TWh, offshore wind power use is decreased by 5 TWh. The use of biogas and small hydro power do not show remarkable differences between the two cases. As in the EU-15 it can be noted that the mixture of RES-E capacities installed slightly differs from the scenarios with renewable electricity targets, as the level of support given to some technologies makes them more attractive than this is the case with their actual cost structure. In this case the feed-in tariffs also allow an additional 1.2 TWh of geothermal power to become viable, as well as 1.5 TWh of electricity from solar thermal installations. The latter is not realised at all without incentives.

While the cost-minimising model approach suggests a very high exploitation of the comparatively cheap renewable potentials to fulfill the 2020 renewable target, the implemented feed-in tariffs do not allow to reach this share (cf. Figure 58). Nevertheless, the renewable electricity utilisation is increased by a further 64 TWh compared to the TARGETS_national scenario. This corresponds to a realised renewable electricity share of over 31% in 2020, and thus significantly above the national target of 20% for this year. Compared to the TARGETS_national scenario wind energy use in 2020 is almost 11 TWh lower and, most importantly, the large contribution of geothermal electricity is reduced by more than 51 TWh. While also the use of biogas (-2.5 TWh) shows a slight decline, hydro power and biomass utilisation stay on an unchanged level. Only solar thermal potentials can be realised on a slightly higher level (+1.5 TWh). The reduced power production from renewable energy carriers compared to the 2020 period of the TARGETS_national scenario is only partially compensated for by indigenous conventional power generation. While the power production from natural gas is increased by almost 45 TWh, the more carbon intensive power production from coal and lignite is reduced by 8 TWh for each of the two energy carriers. The remaining electricity demand is covered by an increased level of electricity imports, which is 35 TWh greater than in the TARGETS_national scenario.

Generally, the additional, CO_2-free renewable power production in Germany achieved in the scenarios with promotion schemes allows to reduce the high electricity imports of the REFERENCE scenario. The situation for 2010 in the TARGETS_national scenario and the INCENTIVES scenario is shown in Figure 59 and can be compared to the situation in the REFERENCE scenario in Figure 45 on p. 161. The increased use of practically CO_2-free renewable electricity can thus also contribute to the reduction of the effects invoced by the nuclear phase-out in combination with the EU emission trading system.

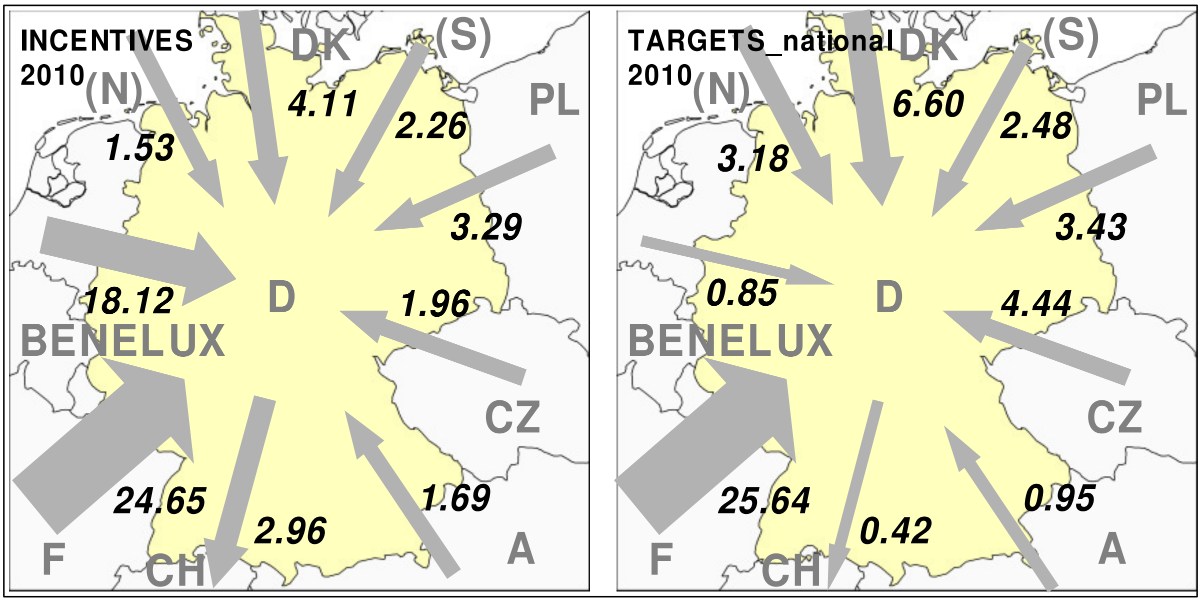

Figure 59: German electricity exchange balance (INCENTIVES vs. TARGETS_national)

Both in France and in Spain, the financial incentives granted do not lead to significant differences of the renewable power production in 2010 when compared to the TARGETS_national scenario. Both countries achieve only slightly lower penetrations than would be necessary to fulfill their national targets. In France, wind energy use is reduced by about 9 TWh, while almost 5 TWh more electricity from biomass and biogas is produced. In Spain the slight decrease is about equally distributed between wind energy and biogas.

More significant differences occur in both countries in 2020. In France renewable electricity generation achieved by the given financial incentives in 2020 differs from the TARGETS_national scenario mainly in the use of power generation from biomass (-23 TWh), from wind (-22 TWh) and from biogas (-4 TWh). The difference in renewable electricity production is equalised by an increased conventional generation from nuclear fuels (+39 TWh) and natural gas (+10 TWh). Compared to the cost-minimised solution for the ambitious 2020 target the incentives in Spain can only achieve a reduced wind energy generation (-6 TWh) as well as less electricity from biogas (-2 TWh) and almost 5 TWh less from solar thermal installations. For compensation, electricity production from natural gas is 30 TWh higher, while the use of emission intensive coal fired generation is reduced by 19 TWh. Moreover, an additional 4 TWh of electricity are imported.

A quantification of the cost effects, including the total and specific additional costs incurred by the promotion of renewable electricity sources is given in the next paragraph.

9.3.4.4 *Cost effects of an increased renewable electricity utilisation*

In the following, the cost effects of the increased renewable electricity shares due to the applied promotion instruments shall be assessed.

Table 27 shows the evolution of the marginal costs of CO_2 reductions. It can be noticed that the marginal costs of CO_2 reduction with the additional renewable targets in the TARGETS_national scenario are significantly lower than in the REFERENCE scenario. This is explained by the fact that with the targets, less and cheaper conventional reduction options like the fuel switch from coal to natural gas are sufficient to achieve the required CO_2 reductions. Thus, although the mandatory use of renewable electricity causes higher total system costs, the increased exploitation of RES-E potentials has positive effects on the CO_2 certificate prices. In the periods up to 2015 of the INCENTIVES scenario, more RES-E potentials are used than in the scenarios with targets. This is also expressed in lower marginal CO_2 reduction costs until then. With a comparatively lower amount of RES-E potentials realised in the 2020 period of the INCENTIVES scenario, the certificate price is higher again, as more expensive conventional reduction measures need to be realised instead.

Table 27: Influence of renewable electricity support on the marginal costs of CO_2 reduction

	2005 - 2007 [€/t CO_2]	**2008 - 2012** [€/t CO_2]	**2013 - 2017** [€/t CO_2]	**2018 - 2022** [€/t CO_2]
REFERENCE	9.9	20.4	23.7	25.4
TARGETS_national	8.8	17.3	19.8	16.7
TARGETS_EU	8.8	17.6	20.2	16.7
INCENTIVES	5.8	16.5	19.7	20.9

Looking at the development of the marginal costs of power production, it can be noted that the mandatory introduction of RES-E mitigates the increase of marginal generation costs in all EU-15 countries. For some exemplary countries with different capacity mixes the development in the TARGETS_national scenario versus the reference case is shown in Table 28.

Table 28: Average annual marginal costs of power production (TARGETS_national vs. REFERENCE)

	REFERENCE [cent/kWh]					**TARGETS_national** [cent/kWh]				
	2000	**2005**	**2010**	**2015**	**2020**	**2000**	**2005**	**2010**	**2015**	**2020**
DE	1.9	3.0	3.8	4.2	4.6	1.9	2.9	3.4	4.0	4.0
ES	2.8	4.1	4.7	5.1	5.3	2.8	4.0	4.4	4.9	4.7
FR	1.6	2.7	3.0	3.9	4.0	1.6	2.6	2.6	3.1	3.7
IT	4.2	4.0	4.4	4.7	5.0	4.2	3.9	4.2	4.6	4.8
UK	2.9	3.0	3.4	3.8	3.7	2.9	2.9	3.2	3.6	3.7

The EU-15 average in 2020 is 4.0 cent/kWh versus 4.3 cent/kWh in the REFERENCE scenario. This mitigation is more significant in countries with a high share of natural gas use in the REFERENCE scenario. With the ambitious renewable target in 2020, marginal costs of electricity production actually can be lower than in 2015 in some countries, as e.g. in Germany and Spain. This can be explained by the fact that the mandatory use of renewable electricity substitutes conventional technologies and shifts the merit order curve in a way that allows the remaining demand to be covered by technologies with lower marginal generation costs.

Next, the additional costs caused by the production of renewable electricity in the EU-15 Member States are analysed. For each scenario with a promotion of renewable electricity use, these are derived from the difference of renewable power production costs in the respective scenario and the renewable power production costs in the REFERENCE scenario.

With almost 22.7 billions of Euros the highest costs are induced in the INCENTIVES scenario. In the TARGETS_national scenario these costs are somewhat lower, amounting to 21.4 billions of Euros. With an ideal green certificate trading system, as assumed in the TARGETS_EU scenario, the cost-optimised exploitation of the available renewable electricity potentials would cause additional costs of 15.3 billions of Euros. The reduced additional costs in the TARGETS_EU scenario are due to the relocation of renewable electricity use from regions where the compliance with the national target is especially expensive (e.g. Italy, Spain and Sweden) to other European regions with less expensive available potentials (mostly Germany and the United Kingdom, to a lesser extent also Denmark, Finland and the Netherlands). In 2020 the difference between the additional RES-E production costs for target compliance in the TARGETS_national scenario (66.2 billions of Euros) and the TARGETS_EU scenario (63.3 billions of Euros) is much smaller. Contrary to 2010, the additional costs of RES-E production in the INCENTIVES scenario are much lower, totalling 32.6 billions of Euros. This is due to the fact that in this case the 2020 target for RES-E is not accomplished. Both in 2010 and 2020 the highest additional costs naturally occur in the regions with most additional RES-E utilisation. These are Germany, France, the United Kingdom and Spain, and in the case of national targets also Italy.

Moreover, the average costs per additional kWh of renewable electricity produced due to the specified promotion measures are determined. For each Member State, as well as for the EU-15 as a whole, they are derived from the ratio between the costs incurred by additional renewable electricity use and the additional amount of renewable electricity produced. In 2010 the average costs per additional kWh of RES-E throughout the EU-15 range from 8.0 cent under the idealised GCT conditions in the TARGETS_EU scenario up to 9.8 cent in the INCENTIVES scenario. In the TARGETS_national scenario the corresponding value is 9.1 cent/kWh. In 2020, one average additional kWh of RES-E in the EU-15 is somewhat more expensive, 9.1 cent/kWh in the TARGETS_EU scenario and 9.5 cent/kWh in the scenario

TARGETS_national. Without the obligation to fulfil the 2020 RES-E target, the average additional kWh of RES-E is least expensive in the INCENTIVES scenario at 8.7 cent/kWh.

According to the theoretic expectations for a perfect GCT scheme, it is observed that the spread between the average costs per additional kWh of RES-E between the countries is reduced in the TARGETS_EU case. In 2010 their value varies between 6.4 cent/kWh and 16.8 cent/kWh in the TARGETS_national scenario. In the TARGETS_EU scenario the variation is smaller, between 5.9 cent/kWh and 9.1 cent/kWh. In 2020 the corresponding cost ranges are 7.6-13.8 cent/kWh in the TARGETS_national scenario and 7.4-10.9 cent/kWh in the TARGETS_EU 2020 scenario.

More generally, the model results under the different target specifications indicate which technologies should be promoted where in the EU-15 and to what extent, in order to reach the specified goals. The specific production costs of the most expensive potential of a technology that is realised in a country in the model runs can thus be interpreted as the minimum level of a technology-specific financial incentive, which needs to be provided in this country to achieve the given share of the technology in the mix[193]. Similarly, the realised potentials of each renewable technology can be interpreted as the economically most efficient technology-specific quotas under a given development of fuel prices and CO_2 emission restrictions.

Further, the marginal costs of RES-E target compliance are determined. These can be seen as an indicator for the certificate price under an ideal, Europe-wide Green Certificate trading scheme. In the TARGETS_EU scenario, with cumulative targets specified for the EU-15 in 2010 and 2020, the marginal target compliance costs amount to 24.7 cent/kWh in 2010, and to 57.6 cent/kWh in 2020. Without any limitations of the expansion rate of the potentials as in the TARGETS_EU_INF scenario, i.e. if only the absolutely least expensive potentials can be developed at arbitrary expansion rates, marginal costs would be lower, both in 2010 (20.3 cent/kWh) and especially in 2020 (21.6 cent/kWh)[194]. The differences resulting from a limited versus an unlimited expansion rate of renewable potentials are discussed in section 9.3.6.

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[193] In the case of a premium system, the minimum premium necessary would be the specific production costs of a given renewable technology minus the average power generation costs. However, it can be observed in reality that decisions to tap the available potentials are not always primarily dependent on more favourable costs for their development. Next to the production costs the entrepreneurial risk, and thus also the decision to construct a renewable energy conversion unit, are crucially determined by other conditions, as e.g. the duration and calculability of the promotion scheme or grid access regulations (cf chapter 3.5).

[194] The marginal compliance costs determined are not technology-specific. Without any technology-specific differentiation in their practical implementation, this would cause high windfall profits for producers with cheap potentials. The cost optimised contribution of renewable energy technologies for target compliance indicated in the PERSEUS-RES-E model results can be seen as an ideal starting point for the implementation of such technology-specific quotas

Finally, by relating the difference of total system expenditures in the scenarios with RES-E promotion and those in the REFERENCE case to the total amount of electricity produced in each region, the net additional costs per kWh of total electricity production are determined. In Table 29 the additional costs for renewable electricity related to the total electricity generation are shown for all scenarios with a promotion of renewable electricity. In the 2020 period of the INCENTIVES scenario these are generally equal to or lower than those in 2010 in the countries with a quota-based scheme, as no quota beyond that for 2010 has been specified. In the case of the United Kingdom, this even results in a cost advantage. The weighted average for the EU-15 indicates that in the hypothetic case of unlimited growth rates (called TARGETS_EU_INF, cf. also section 9.3.6) one kWh of electricity would become at least about 0.4 cent more expensive by fulfilling the cumulative EU-15 renewable electricity target in 2010. In the worst case with national targets for 2010 and a cumulative EU-15 target for 2020 this increase would be about 50% higher at almost 0.6 cent/kWh. The fulfillment of the cumulative 2020 target would increase the average generation costs for one kWh of electricity in the EU-15 by an amount between 1.50 cent to 1.92 cent.

Table 29: Specific additional costs of power generation due to renewable electricity generation [cent/kWh(total)]

Country	2010 [cent/kWh(total)]				2020 [cent/kWh(total)]			
	TARGETS_national	TARGETS_EU	TARGETS_EU_INF	INCENTIVES	TARGETS_national	TARGETS_EU	TARGETS_EU_INF	INCENTIVES
AT	0.3	0.1	0.3	0.5	1.2	1.2	1.1	1.0
BE	0.3	0.2	0.2	0.3	0.9	0.9	1.0	0.3
DK	0.6	0.9	0.2	0.3	2.5	2.7	3.0	0.4
FI	0.2	0.3	0.3	0.3	0.7	0.8	1.0	0.4
FR	0.3	0.3	0.2	0.3	0.9	0.8	0.9	0.4
DE	0.4	0.6	0.2	0.7	3.5	3.7	2.6	1.8
UK	0.7	0.7	0.6	0.5	0.8	0.9	1.1	-0.5
GR	0.8	0.4	0.6	0.7	1.5	1.4	1.4	1.0
IR	1.5	1.5	2.1	0.5	3.4	3.4	3.4	0.3
IT	1.5	0.1	0.4	1.7	1.5	0.8	0.9	1.1
LU	0.3	0.4	0.3	0.2	1.3	1.4	1.2	0.5
NL	0.5	0.6	0.3	0.6	1.1	1.2	1.4	0.8
PT	0.2	0.3	0.3	0.1	1.2	1.2	1.2	0.1
ES	0.8	0.5	0.7	0.7	1.4	1.4	1.3	0.9
SE	0.6	0.2	0.2	1.3	1.5	1.2	1.4	0.9
EU-15	**0.59**	**0.52**	**0.39**	**0.52**	**1.92**	**1.93**	**1.50**	**0.75**

For a household of 4 persons and an average electricity consumption of about 4,400 kWh/a, this implies a maximum additional financial burden of 2.17 €/month in 2010, and 7.04 €/month in 2020.

A cost component not included in the above results are the costs for grid expansions and reinforcements. For the grid expansions determined to be necessary in Germany until 2015, maximum average additional costs of 0.025 cent per kilowatt hour of power generated in Germany have been calculated (cf. [Dena 2005]). Even if more reinforcements or new lines should become necessary for higher installed wind turbine capacities than investigated in the Dena study, the order of magnitude of these costs is relatively small when compared to the overall additional costs of wind energy feed-in.

Although the German feed-in tariffs are not regarded as subsidies by the European Court of Justice [EuGH 2001], a short comparison of the amount of feed-in tariffs paid to the amount of coal subsidies in Germany shall be given: In the year 2000, hard coal extraction in Germany was subsidised with 4.4 billions of Euros, corresponding to a financial contribution of 4.3 cent for each kWh of power produced from German hard coal. In 2004 the corresponding values decreased to 2.6 billions of Euros in total and 3.2 cent/kWh from German hard coal[195]. When related to the overall net electricity generation in Germany, this corresponds to 1.06 cent/kWh in 2000 and 0.71 cent/kWh in 2004. From 1980 to 2003 a total of 146 billions of Euros of state aids were paid for hard coal mining in Germany, averaging at a higher annual value of 6.3 billion Euros [UBA 2003]. The value for coal subsidies of 0.71 cent/kWh in 2004 was about equally high as the expected specific additional costs for renewable electricity use in the INCENTIVES scenario in Germany in 2010.

9.3.5 Influence of fluctuating renewable electricity production

After assessing the influences of different specifications for renewable electricity use on the composition and the utilisation of the conventional electricity system as well as the resulting additional costs, this part of the scenario analysis deals in particular with the technical effects of wind power related fluctuations on the composition and operation of the power system. It is thus especially relevant for the EU-Member States with the largest potentials and the highest utilisation of wind energy, like Germany, the United Kingdom, France, and Spain. In order to quantify the effects for a high and simultaneously efficient utilisation of renewable electricity potentials, the analysis is performed under the general conditions of the TARGETS_EU scenario.

Generally, the analysis covers two aspects. Firstly, the conventional reserve capacity requirements, which result from the low secured capacity of wind turbines and the necessary tertiary reserve capacities are quantified. Secondly, the effects caused from changed patterns of power plant operation with more plant start-ups and longer operation in partial load conditions are described. The latter are determined with

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[195] Own calculations based on [Boss et al. 2006] and [Kohlenstatistik 2005].

Aeolius and transferred into PERSEUS-RES-E, as described in chapter 5.5 and chapter 6. The assessment includes the quantification of the corresponding costs for capacity installation and operation for both of the above aspects, as well as the CO_2 emissions that result from the changed patterns of power plant operation.

9.3.5.1 Reserve requirements

In order to take into account the increased demand for tertiary reserves associated to the growing utilisation of fluctuating wind energy (cf. chapter 4.3), these reserve requirements have been integrated into the model for all regions that utilise wind energy. This demand is highest in the scenarios INCENTIVES and TARGETS_EU, where the largest amounts of wind power capacities are installed.

Figure 60 and Figure 61 illustrate how the reserve requirements affect the installed capacities and the power production in the countries with the largest available wind energy resources in the EU-15 and in the EU-15 as a whole.

In 2020, the additionally installed capacity of natural gas fired power plants in Germany lies 6.1 GW above the capacity that would be installed without this requirement. Besides, about 0.8 GW more of the coal fired capacities remain in use, while a capacity of 0.8 GW of offshore wind turbines is not installed in this period. In 2020 the corresponding differences are 0.6 GW more hard coal fired capacities, 11.9 GW more gas fired units and also 0.8 GW less capacity of offshore wind turbines.

In Spain the reserve requirements necessitate an additional natural gas fired capacity of 1.9 GW in 2010 and 5.5 GW in 2020. In both periods, 0.4 GW of oil fired capacities remain in the power plant mix, while the installed wind turbine capacities are not changed.

Similar to Germany, the reserve requirements in France also lead to a prolonged utilisation of existing coal fired capacities. Compared to the case without reserve requirements, an additional capacity of 1.1 GW remains in service from 2010 onwards. While this additional capacity is sufficient for the wind power share in 2010, the increasing penetration of wind capacities in 2015 and 2020 necessitates more reserves. These are provided by an additional 3.2 GW of natural gas fired capacity in 2015, and another 3.6 GW in the year 2020. Thus, a total of 7.9 GW of additional reserve capacities are installed in 2020.

After Germany, the United Kingdom has the second highest expansion of wind power in the EU-15. This is also expressed in the additional reserve requirements. With a lot of gas fired capacities in the mix already in the earlier periods, additional reserve requirements are a bit lower than in Germany. In 2010, less than 0.5 GW of additional natural gas fired capacities must be commissioned in addition. In 2020, this requirement increases to a total of 8.6 GW. A prolonged utilisation of existing coal fired capacities is less favourable than e.g. in Germany and France. Only the decommissioning of 1.1 GW of coal fired capacities is postponed from 2015 to 2020, when it is replaced by natural gas fired capacities.

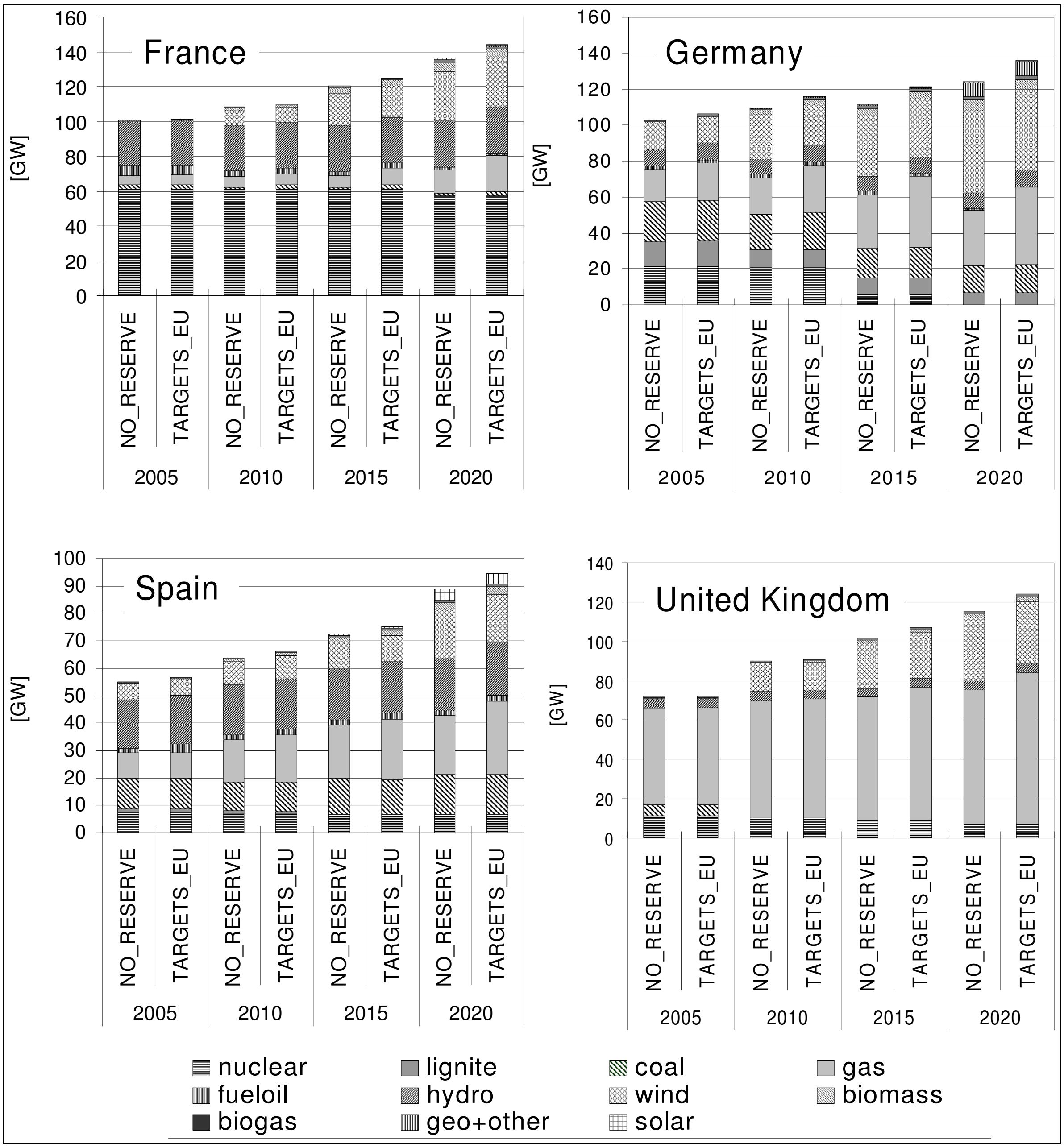

Figure 60: Influence of tertiary reserve requirements for wind energy in selected countries

With almost 35 GW of additional tertiary reserves, Germany, the United Kingdom, France, and Spain have to commission about 70% of the total additional reserve capacities necessary within the EU-15 in order to balance the wind power utilisation in 2020.

Across the EU-15 the increased demand for reserve capacities in the TARGETS_EU scenario compared to the NO_RESERVE case is almost entirely satisfied by natural gas fired capacities. Throughout the EU-15 the reserves for wind power fluctuations necessary in 2010 amount to 12.1 GW of natural gas fired capacities and an additional 4.1 GW of coal fired power plants. In 2020, the increased reserve requirements are met by 46.6 GW of natural gas fired capacities, while the additionally necessary coal fired reserves remain at a practically constant value of 4.0 GW. Moreover, when compared to the case without reserve requirements, 0.7 GW less offshore wind turbine capacities are installed all over the EU-15 in 2010 and also in 2020.

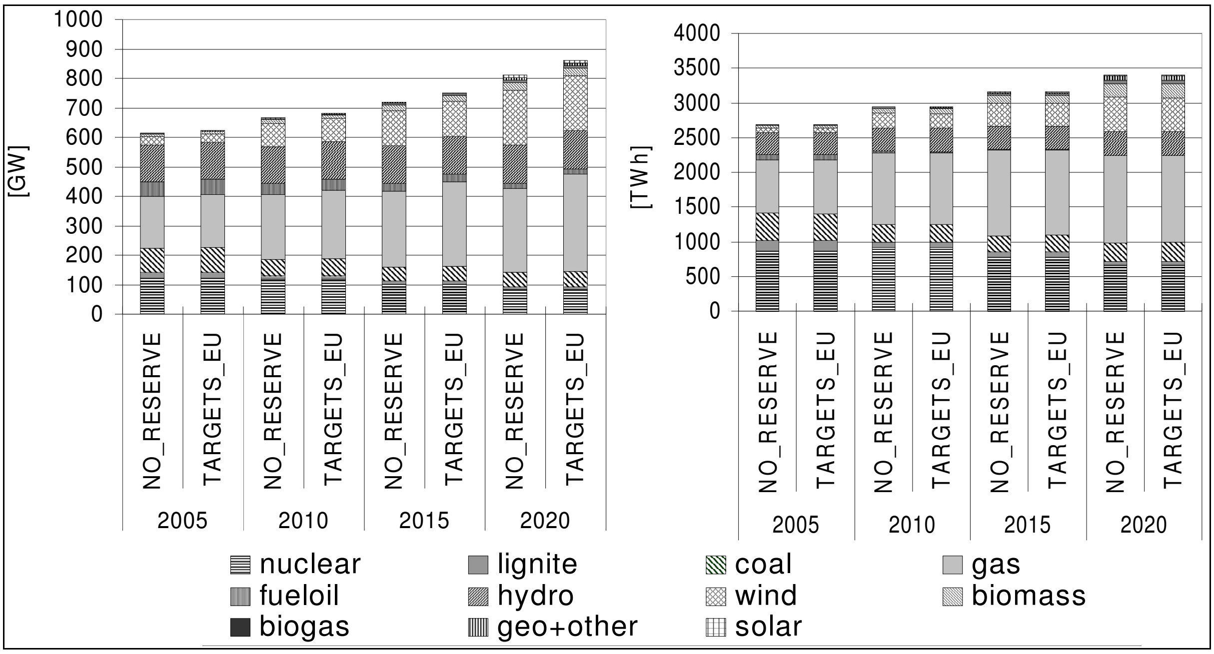

Figure 61: Influence of tertiary reserve requirements for wind energy in the EU-15

The results for the above Member States and the EU-15 in total indicate that due to their low specific investments and high flexibility concerning load variations, natural gas fired capacities are the favourite choice to cover the additional reserve requirements. The provision of these additional capacities in the regions with a high wind energy utilisation is reflected in additional expenditures. In Table 30 and Table 31 these additional expenditures are related to the amount of wind energy produced and to the total production of electricity, respectively, for the four European countries with the highest utilisation of wind energy as well as for the EU-15 as a whole.

Table 30: Cost differences caused by capacity reserve requirements (per kWh of wind power)

	2005	2010	2015	2020
	[cent/kWh]	[cent/kWh]	[cent/kWh]	[cent/kWh]
France	1.89	0.43	0.51	0.45
Germany	0.26	-0.12	0.09	0.13
United Kingdom	1.12	0.31	0.61	0.61
Spain	0.29	1.00	0.80	0.67
EU-15	0.29	0.25	0.39	0.44

Compared to the other countries with a high wind power share, Germany faces lower specific costs for its additionally necessary capacity reserves. This is due to a combination of reasons. Firstly, when e.g. compared to the French electricity system dominated by unflexible nuclear capacities, a comparatively large margin of conventional reserves already exists from the beginning of the modelled time horizon. These are mostly coal fired and pumped storage plants, plus some natural gas fired capacities. Secondly, during the fundamental restructuring of the power sector in Germany due to the nuclear phase-out and the comparatively strict emission limitations, large capacities of more flexible natural gas fired power plants are added anyway. To provide the necessary reserves, production from these capacities is lowered, and the resulting production deficit is imported instead. This is the cheapest option to reduce the additionally necessary and more expensive measure of capacity additions to a minimum. The combination of these effects even leads to a situation in 2010 where due to the diminished power production in Germany the costs in the German power sector are actually lower with the reserve requirement in place than without this requirement.

Table 31: Cost differences caused by capacity reserves (per kWh of total electricity generated)

	2005	2010	2015	2020
	[cent/kWh]	[cent/kWh]	[cent/kWh]	[cent/kWh]
France	0.00	0.02	0.03	0.04
Germany	0.01	-0.01	0.02	0.03
United Kingdom	0.00	0.03	0.09	0.12
Spain	0.02	0.08	0.07	0.09
EU-15	0.01	0.02	0.04	0.06

The other considered countries are not forced into such a fundamental restructuring of their power sector. Thus they have to install comparatively more additional reserve capacities, which leads to higher specific additional costs for the fulfilment of their reserve requirements. In the United Kingdom the absence of significant hydro power reserves also contributes to a comparatively high level of additional costs for capacity reserves.

9.3.5.2 Efficiency losses

For the determination of the fluctuation-induced efficiency losses, the hybrid modelling approach described in chapter 5.5 and in chapter 6.6.2 is applied to Germany and Spain. In the following, the results of its application in the scenario with the highest wind power expansion in these two countries, i.e. the TARGETS_EU scenario, shall be described. After a model run of PERSEUS-RES-E without taking any efficiency losses into account, model runs with the AEOLIUS simulation model are conducted for each characteristic year of the modelled time horizon. For each of these years, the capacity structure of the power plant portfolio and the wind energy feed-in as determined by PERSEUS-RES-E are taken into account in the corresponding AEOLIUS model run. With this procedure, which is described in in more detail in chapter 6.6.2, the efficiency losses due to wind power fluctuations are determined for each characteristic year. They are expressed as specific costs and specific emissions per unit of wind power produced.

The left part of Figure 62 shows the fluctuation-induced emissions per kWh of wind energy feed-in due to wind power fluctuations in Spain and in Germany. The fluctuation-induced costs per kWh of wind power are shown in the right part.

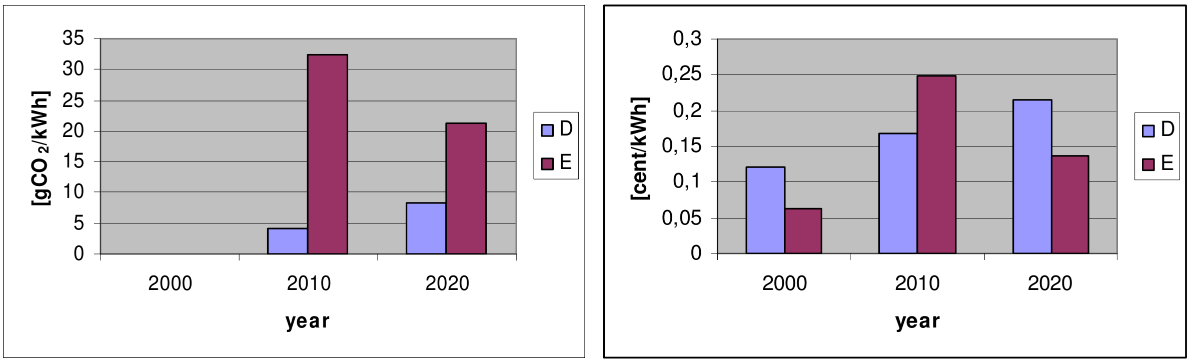

Figure 62: Additional emissions and variable operating costs induced by wind power fluctuations

Specific fluctuation-induced emissions in Spain

In the base year 2000 the use of wind energy is still comparatively small in both countries. The variations caused in the residual load are small and can be compensated in an emission-neutral manner by the use of flexible natural gas capacities instead of coal or lignite.

In the year 2010, the specific fluctuation-induced emissions per kWh of wind energy increase to 32 gCO_2/kWh, which is the highest value in Spain throughout the considered time period. On the one hand, an increased use of natural gas and a reduced use of coal for the compensation of the fluctuations are observed in AEOLIUS. But due to the still coal-dominated structure of the electricity system, emissions do not decrease as might be expected. Instead, the increased number of coal plant start-ups and shutdowns leads to start losses that overcompensate the substitution of coal production by gas production.

In 2020 specific emissions related to the wind power fluctuations in Spain decrease to 21 gCO_2/kWh, which is due to two factors. Firstly, the increase of wind power use beyond 2010 flattens out considerably. Secondly, the restructuring of the fuel use in Spain with gas use increasing more than wind power feed-in, allows a more efficient balancing of fluctuations due to less partial load and startup losses.

Specific fluctuation-induced emissions in Germany

As in Spain, the influence of wind power fluctuations on the residual load in the year 2000 is small enough to be compensated by an increased use of flexible gas capacities and a diminished use of coal or lignite capacities. The emissions caused by additional plant start-ups and operation at partial load are in the same order of magnitude as the emission savings achieved by the substitution of small amounts of coal and lignite by less CO_2-intensive natural gas. Thus, the specific additional emissions caused by the fluctuations are negligible in this period.

In 2010, fluctuation-induced emissions have to be accounted for. However, at 4.5 gCO_2/kWh the additional emissions per kWh of wind energy feed-in are much lower than in Spain. This is due to the fact that, compared to the modelling of wind power as a constant band, less lignite fired base load can be produced at the high wind power feed-in with fluctuations taken into account. Instead, less CO_2-intensive but more flexible coal and gas power plants substitute a part of the lignite production, which reduces the additional emissions.

In 2020 the fluctuation-induced emissions in Germany increase to 8 gCO_2/kWh. The increase is in line with the almost unbroken rise in wind power production, but due to the same shift in capacity use as described before for 2010 it is comparatively low.

Specific fluctuation-induced costs in Spain

The increased use of more expensive natural gas as a fuel leads to specific fluctuation-induced costs of about 0.06 cent/kWh of wind energy in the year 2000.

In 2010, similar to the fluctuation-induced emissions, also the specific fluctuation-induced costs reach a maximum at 0.25 cent/kWh. The increased use of gas and a reduced use of coal for the compensation of the fluctuations, but also the fuel losses due to partial load operation and more frequent plant start-ups in the coal-dominated generation system are the reasons for higher specific fluctuation-induced costs.

Analogously to the specific emissions also specific costs related to the wind power fluctuations decrease in Spain, reaching a value of 0.14 cent/kWh in 2020. The slower increase of wind power use beyond 2010 and the restructuring of the fuel use in Spain, with gas use increasing faster than wind power feed-in, allow a more efficient balancing of fluctuations also with respect to costs.

Specific fluctuation-induced costs in Germany

In 2000, a higher wind power feed-in level in Germany and the corresponding stronger fluctuations lead to a value of 0.12 cent/kWh for specific fluctuation-induced costs. This value is higher than in Spain, which has only about half of the wind power to absorb in its power system.

In line with the high growth rate of wind energy use up to 2010, fluctuation-induced costs rise to 0.17 cent/kWh in this period. As for the emissions, also this value for the specific additional costs is lower than in Spain. The main reason for this can be seen in the fact that the higher share of flexible gas capacities installed causes comparatively lower losses due to plant start-ups and partial load operation.

In 2020 the fluctuation-induced costs in Germany, in a similar trend as fluctuation-induced emissions, increase to 0.22 cent/kWh. Different from the situation in Spain, the continuing steep increase in wind power production does not allow a decrease of this value. Although more flexible gas capacities are also available in this period, their rate of increase is lower than that of wind energy, leading to a comparatively larger contribution of coal power plants necessary to cover the fluctuations. The partial load operation and additional plant start-ups of this technology lead to higher associated fuel losses.

Total fluctuation-induced efficiency losses

Here, the total effects in PERSEUS-RES-E - in terms of power production costs and CO_2 emissions - are described. Table 32 shows the resulting total additional system costs due to the balancing of wind power fluctuations in Germany and Spain. Corresponding to the larger installed wind power capacities, the additional costs in Germany are higher than in Spain from the year 2000 onwards. The slight decrease of additional costs and emissions in Spain between 2010 and 2015, despite growing wind energy use, indicates that the restructuring of the generation mix in 2015 also allows for a better adaptation to large amounts of wind power.

Table 32: Additional costs for balancing of wind fluctuations (TARGETS_EU_FLUCT vs. TARGETS_EU)

	2000	2005	2010	2015	2020
	[mio.€/a]	[mio.€/a]	[mio.€/a]	[mio.€/a]	[mio.€/a]
Germany	11.2	41.6	103.1	172.6	260.7
Spain	2.8	22.0	54.3	51.3	64.2

Moreover, Table 33 shows the additional emissions in both countries. The moderate fluctuations induced by the small amounts of wind power capacities installed in the year 2000 can be balanced without causing additional emissions. In later periods with increasing wind energy use, the comparatively lower amount of wind energy in the Spanish electricity sector causes higher additional emissions than wind power use in Germany. These higher efficiency losses in terms of emissions are explained by the less flexible and more emission intensive generation mix in Spain, which contains higher shares of coal and unflexible nuclear power production throughout the time horizon than the increasingly natural gas dominated German electricity sector.

Table 33: Additional emissions for balancing of wind fluctuations (TARGETS_EU_FLUCT vs. TARGETS_EU)

	2000	2005	2010	2015	2020
	[$MtCO_2$/a]	[$MtCO_2$/a]	[$MtCO_2$/a]	[$MtCO_2$/a]	[$MtCO_2$/a]
Germany	0.00	0.06	0.27	0.54	0.95
Spain	0.00	0.22	0.71	0.69	0.96

The specific and total additional operating costs caused by the balancing of wind power fluctuations are lower than the corresponding additional capacity related costs (annuities and annual fixed costs) for tertiary reserves identified before. Both of these cost components together are again rather small in comparison to the total additional costs for the use of wind power technology. Thus, the influence of these components on the choice of the renewable production mix and the regional distribution of renewable capacities is very limited.

Likewise, the additional emissions caused in both countries are small in relation to the total emissions in the European electricity system. Thus, their influence on the marginal CO_2 reduction costs is very low and does hardly exceed 0.1 €/tCO_2 during all modelled time periods. A precondition for this small impact also at high wind energy penetration rates are the growing shares of more flexible and less CO_2-intensive natural gas fired capacities. These are installed anyway as an answer to the increasingly strict emission limitations.

Thus, the above results for the two countries Spain and Germany with their current relatively CO_2-intensive power production mix reveal obvious synergies between the adaptation of the electricity systems' structures to tightened CO_2 reduction targets and their ability to take up large amounts of fluctuating wind power.

9.3.6 Influence of restrictions and technological barriers for renewable energies

Differently strong restrictions can apply to the possible expansion of renewable electricity use. In the following, their influence on the technology mix is considered. The differences in the additional costs for renewable electricity use can be derived from Table 29 on p. 194. In order to achieve realistic results for the future realisation of renewable electricity shares, the introduction of such restrictions is reasonable from a modelling point of view. In general, comparatively inexpensive renewable energy technologies like wind power or biomass technologies are most attractive to fulfil a specified renewable electricity target. These energy carriers also possess large potentials in many EU-15 countries. Without a limitation of the expansion rate, the cost-minimising approach of PERSEUS-RES-E will choose an immediate realisation of large potentials in the years 2010 and 2020, for which targets are specified. Thus, extremely high growth rates can result in these years[196]. In reality, the growth rates necessary for such an immediate realisation of renewable electricity potentials are limited. This is due to a number of factors, including permitting procedures, the expansion of the grid connections, and the possible growth rate of capacities for production and logistics in the manufacturing industry[197].

Thus, in all scenario calculations described so far, a global limitation of the capacity growth rate (expressed in MW/a) has been implemented for all available potentials. This limitation is specified in addition to a linearly increasing bound on the maximum amount of electrical energy yield from the renewable potentials in each period

[196] This behaviour of the model can also be interpreted as a kind of bang-bang effect (cf. section 7.3.4.2).

[197] The latter are especially decisive for the construction of off-shore wind parks, as the majority of the necessary port capacities and specialised barges and vessels for the erection of turbines do not yet exist. Thus, they still have to be planned and constructed with the according lead times, and especially in the case of port capacities competition with the increasing distribution volumes of other goods can be expected.

(expressed in TWh/a). While high capacity growth rates, especially for wind energy, are currently observed, it has been assumed in the model that on average the growth rates can not exceed the linear increase rate between the realised renewable electricity potentials in the year 2002 and the hypothetical realisation of the total available potential in 2020 by more than 50%. This limitation corresponds approximately to the vigorous increase rates of wind energy use observed in Germany. In the following, the influence of this growth rate limitation is illustrated. In Figure 63 a comparison of the fulfilment of renewable electricity targets with and without a limitation of the possible growth rate is shown. The restrictions are of special relevance in the year 2015. Without any restrictions of the possible expansion rate or an intermediate target to be fulfilled in 2015, no significant additions of RES-E capacities are made in this period compared to 2010. Instead, the 2020 target is fulfilled immediately in 2020.

It is important to note that a limited average rate of annual increase in the utilisation of renewable energy technologies has no effect on the total amount of renewable electricity production - the target is given anyway - but on the technology mix. Especially for fulfilling the 2020 target, less electricity from offshore wind is produced, and instead more from geothermal and from biogas sources. Even some solar thermal electricity potentials are utilised. An interesting conclusion from this analysis is also that when taking restricted expansion rates into account, offshore wind energy potentials must be developed more vigorously already from 2010 in order to reach the 2020 target.

A difference can also be observed in terms of total costs in the target years 2010 and 2020. Without any restrictions of the expansion rate, the costs incurred by the additional renewable electricity use necessary for compliance with the 2010 renewable target could be reduced from 15.3 billions of Euros to the theoretical minimum of 12.9 billions of Euros. Similarly, the additional costs in 2020 are 63.3 billions of Euros instead of the theoretical minimum of 58.3 billions of Euros.

Further, technological barriers may limit the growth rate or postpone the growth of individual technologies to later time periods. While many RES-E technologies have existed long enough to make the calculation of their potentials and the related costs sufficiently reliable, the set of RES-E technologies considered in the model also contains some technologies whose expected technical and economic performance is not yet completely proven. The expected costs and potentials for these less mature technologies are thus subject to comparatively greater insecurities than those for well established technologies. This is the case e.g. for more complicated foundations for offshore wind turbines in deeper waters. In some (extreme) cases, they may also completely prevent installations from becoming successful. Another example in this context is the performance risk connected to the drillings for Hot Fractured Rock geothermal applications. Technological barriers have to be overcome to realise the potentials that are given, finally probably at higher costs than prospected today, or with only parts of the anticipated potentials being actually realisable.

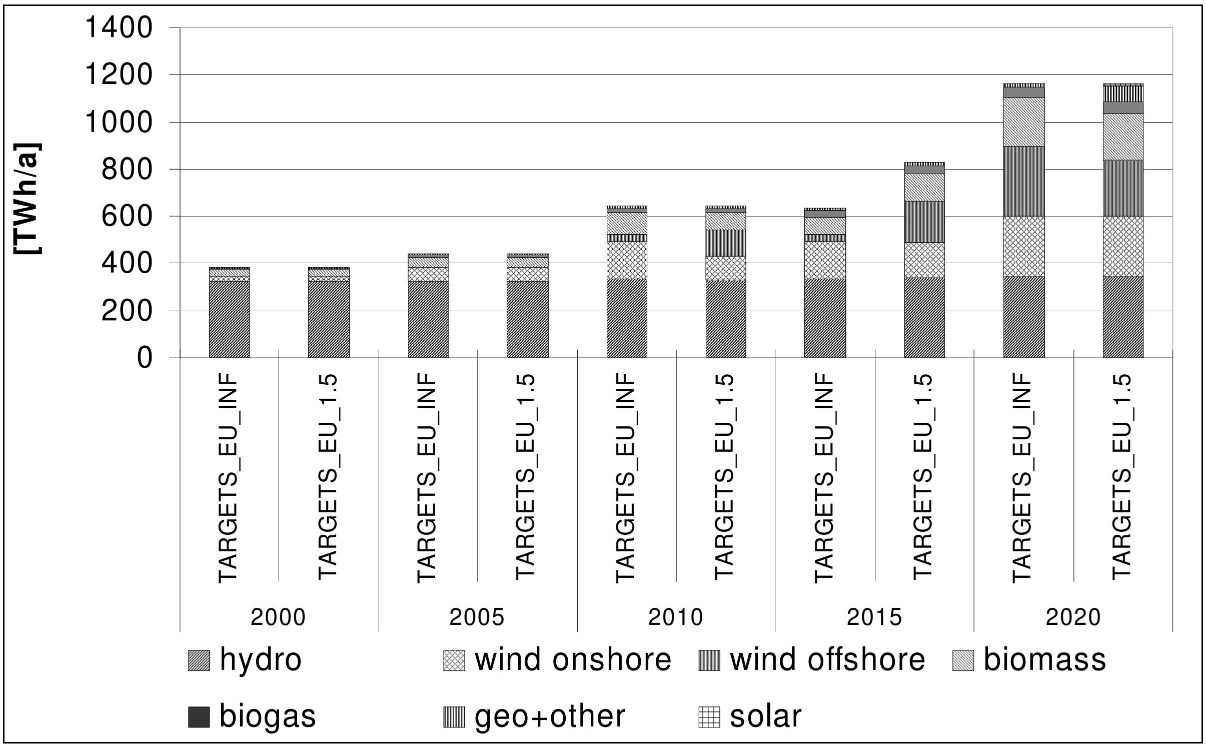

Figure 63: Influence of a limited growth rate on the fulfillment of renewable electricity targets in the EU-15

In the underlying cost and potential data the geothermal Hot-Dry-Rock (HDR) potential has been analysed in more detail for Germany (cf. chapter 8.6.1). The previously described INCENTIVES scenario shows that with the applied feed-in tariffs and assuming that the relevant technical barriers can be overcome, only a small part of this huge potential would be utilised from 2010 onwards. With a conservatively low initial average feed-in tariff of 8.95 cent/kWh assumed for the calculation in the INCENTIVES scenario, only about 7.14 TWh of geothermal electricity are produced in 2020. This is only a marginal part of the total potential in Germany, but due to the characteristics of the cost-potential curve the realisation of HDR potentials is quite sensitive to the level of the feed-in tariff paid. The height of this tariff varies strongly depending on the capacity of the installation[198]. The results in the scenarios with an ambitious long-term renewable electricity target show that with about 60 TWh a power production close to that from offshore wind energy (68.5 TWh) is realised in Germany in 2020. This result already indicates that with a feed-in tariff at the higher end of the scale, i.e. above that for offshore wind energy, a considerable contribution of geothermal electricity production can be achieved. An average initial feed- in tariff of 11.3 cent/kWh, which corresponds to the assumption that more and smaller installations would be built, leads to a generation of 16.3 TWh. And indeed, assuming that the majority of installed plants will have a capacity between 5 MW and 10 MW and a corresponding average feed-in tariff of 14.0 cent/kWh, 122 TWh would be

[198] For geothermal installations larger than 20 MW, 7.16 cent/kWh are guaranteed, 8.95 cent/kWh for installations over 10 MW up to 20 MW, 14.0 cent/kWh for installations over 5 MW up to 10 MW and 15 cent/kWh for installations smaller than 5 MW [EEG 2004].

produced in 2020, exceeding the production of offshore wind energy. The additional production from geothermal electricity mainly serves to reduce German power imports and also increases the emission allowance surplus. This surplus is used to reduce the use of expensive natural gas and instead allows a higher share of the more carbon intensive, but otherwise cheaper fuels hard coal and lignite to remain in the system. Although the large-scale use of geothermal electricity will be more expensive than e.g. the use of the large German wind power potentials, geothermal electricity offers the benefits of a controllable base load technology.

10 Conclusions

Within the still ongoing liberalisation process in the European electricity and gas markets the politically induced integration of substantial amounts of renewable energy sources implies additional strategic challenges for the energy supply in Europe. Along with climate change mitigation efforts and clean air policies the European Commission intends to increase the renewable electricity share from currently 13.9% to 22% in 2010. Specific goals for each EU Member State are set in Directive 2001/77/EC of the European Parliament and of the Council on the ‘Promotion of electricity produced from renewable energy sources’. More ambitious aims, although not officially established yet, are envisaged for 2020. For the short- to mid-term future the politically and environmentally motivated introduction of significant amounts of renewable electricity generation will depend on incentive schemes, although the performance parameters of renewable energy technologies are continuously being improved.

Besides the geographically inhomogenous availability of renewable energy resources, the temporal evolution of renewable electricity market penetration in the EU Member States is influenced by the different design options for national promotion schemes and their possible future harmonisation. Vice versa, the future cost structure of conventional electricity generation also has an influence on the rentability of renewable electricity generation and the necessary support. Moreover, physical interdependencies between renewable and conventional power generation exist. In order to develop adequate policies and strategies policy makers as well as decision makers in utilities must be able to consider the interdependencies and future consequences of their decisions.

In most existing modelling approaches no or only incomplete consideration is given to the above interellated problem fields. Commonly, the use of available renewable resources is not treated as an endogenous variable in the models, but introduced exogenously as a so called expansion path. Other approaches, which focus on the composition of the renewable part of the mix and take into account the available dynamic potentials and incentive mechanisms, are based on static merit order curves for conventional power production. Seasonal load profiles, the international electricity exchange and its interrelation with the ETS are usually not taken into account. The same is true for the interactions of large shares of fluctuating RES-E use with conventional electricity generation. Modelling approaches explicitly focussing on these interactions usually comprise a shorter time horizon with a high temporal resolution, but without regarding intertemporal and inter-regional aspects in the optimisation of the capacity and production mix.

Consequently, the hybrid modelling approach developed in this work aims at combining the relevant long- and short-term aspects of conventional and renewable power generation as well as their interactions on different time scales. Before deriving conclusions from the results of the model-based analysis, the most important characteristics of the developed modelling approach and its suitability for the analysis of the selected research questions shall briefly be highlighted.

10.1 The developed modelling approach for analysing renewable electricity utilisation in the EU-15

A hybrid modelling approach consisting of the optimising long-term energy system model PERSEUS-RES-E and the heuristic model AEOLIUS for the temporally highly resolved simulation of the scheduling of conventional power plants with growing fluctuating wind energy feed-in is developed and applied in this work.

Based on the experiences with previous PERSEUS versions - mainly with the PERSEUS-EVU[199] and PERSEUS-CERT[200] models - the model PERSEUS-RES-E developed in this work allows a sophisticated modelling of renewable power generation in the European electricity sector. The detailed modelling of available renewable resources for electricity generation and the integration of the interactions with conventional power generation identified from relevant scientific studies and with the complementary, newly developed simulation tool AEOLIUS represent a substantial improvement for the analysis of the future developments of renewable electricity generation in the European electricity markets. Taking into account renewable power production in the context of the entire electricity generation infrastructure under the economic, technical, ecological, and political framework conditions, the developed hybrid modeling approach enables a comprehensive quantitative assessment of the future penetration of renewable electricity.

The developed model PERSEUS-RES-E is a multi-regional energy and material flow model, representing the electricity sector of the EU-15 as well as that of six further neighbouring European countries. Methodologically, the model is based on a multi-periodic linear optimisation approach. With its technology-focussed approach and the implemented CO_2 emission trading, it allows for an integrated optimisation of capacity expansion and production planning, as well as an analysis of the interdependencies between those planning areas and the interregional exchange of power and emission allowances.

The model calculations rely on an elaborate database of conventional as well as renewable technology data. About 1,500 individual units represent existing conventional power plant technology classes and expansion options. In addition, approximately 1,500 further units have been integrated into the model to represent the potentials of 15 different renewable energy sources for electricity generation in the Member States of the EU-15. Furthermore, the data basis of the model includes information on the existing transmission system infrastructure, electricity demand profiles as well as the expected demand increase and other energy-economic framework assumptions. The latter include e.g. fuel supply options and energy carrier

[199] See [Fichtner 1999] and [Göbelt 2001].
[200] See [Enzensberger 2003].

price developments. PERSEUS-RES-E is thus a profound tool that allows to derive technically feasible and economically efficient long-term strategies for electricity sector development, taking into account many possible combinations of alternative framework conditions.

The detailed representation of available resources for renewable electricity generation and their interactions with the conventional power sector allow a cost-based, normative assessment to be carried out for different design options of quantity- and price-based incentive mechanisms. It is the aim of these analyses to derive spatially and temporally optimised profiles for the utilisation of conventional and especially of renewable technologies. Among others, the total and specific additional costs for the use of RES-E under the chosen schemes can be determined as a result of these analyses. Moreover, they allow to evaluate the relative importance of these costs in comparison to other influences on system expenditures, such as fuel price changes or the strictness of CO_2 limitations. With the marginal costs of compliance with renewable electricity targets, an indicator for an equilibrium price for green certificates is determined. Based on the specified green electricity quotas for the considered countries, an inter-regional trade with green certificates is represented in the model. In the case of Europe-wide technology or producer specific renewable quota assignments, e.g. under a possible future Community Support Framework, a green certificate trade directly among renewable electricity producers can easily be implemented into the existing model after assigning the corresponding renewable quotas to the obliged electricity producers.

The complementary AEOLIUS model can be applied in two different ways, either on its own or in combination with the PERSEUS-RES-E model. In the first application case, the electricity generation structure remains static and the effects of an introduction of increasing wind energy production into an existing power plant portfolio can be analysed. In the second, dynamic application case, AEOLIUS makes use of the adapted future electricity sector structures determined by the PERSEUS-RES-E optimisation. In this case, the coupled simulation approach enables an evaluation of fluctuating power production and its effects on the production schedules of conventional capacities in the future power sector structures. The subsequent integration of the derived fluctuation-related restrictions into the long-term capacity expansion planning model allows the assessment of the future relevance for the capacity mix, production costs, and CO_2-emissions.

The above features make the modelling approach a useful techno-economic tool to test different design options for future renewable electricity support in advance. Offering a technologically feasible and economically efficient solution for each design option, it can help to derive reasonable, regionally and technologically diversified renewable electricity quotas or feed-in tariff levels for the achievement of future renewable electricity targets. It also allows to determine the most cost-efficient solution for a breakdown of European targets on a national level.

A variety of framework conditions can be regarded and altered in scenarios in order to identify robust solutions. The approach is thus able to contribute to a maximisation of the effectiveness and efficiency of renewable energy support policies, and to achieve a fair future renewable energy burden sharing, avoiding market distortions wherever possible. Thus, the developed models and the results that can be derived make the approach suitable for a variety of applications.

For policy advice and also in research applications it can be used as an instrument to judge the effectiveness and efficiency of existing or planned policy measures as well as their interaction with other policy measures, as e.g. RES-E targets and emission restrictions, or nuclear energy policies. Economically efficient national quotas for a breakdown of more ambitious future EU-wide renewable electricity targets or similar environmental targets can be derived[201].

For manufacturers of conventional and renewable electricity generation technologies the model allows to assess the future market potential based on the technology choices made. Further, utilities and independent power producers can benefit from the model results to support their expansion and contingency planning. Regional and technology-specific information on future market shares and the expected prices for power and CO_2 certificates can be derived, as well as decision support for the investment decision whether renewable energy projects should be started.

However, besides these possible fields of application the limitations of this type of technology-focussed energy model also need to be discussed. As a consequence of the chosen system boundaries the model only represents a selected part of the problem areas relevant for the utilisation of renewable electricity generation technologies. Assuming a perfect foresight represents a simplification of real world decision processes, leading to capacity- or production-related decisions being taken instantly at the required time. The chosen optimisation premise, based on a minimisation of system expenditures, implies a cost-based competition of renewable electricity generation with existing conventional power plants and future expansion options. With investment decisions primarily based on system restrictions, strategic behaviour of market participants, social and other non-technical barriers and drivers are neglected in the chosen approach. Thus, the model is not suited for the analysis of existing and possible future market imperfections. As the value of renewable electricity in the model is determined by the saved costs of conventional electricity generation and without taking into account market imperfections, it can in principle be

[201] It is currently not yet clear whether, at what time, and under which premises a harmonised Community Support Framework (CSF), will be established by the European Commission. In accordance with paragraph 4 of Directive 2001/77/EC the Commission has released a Communication [EC 2005e], which is based on an assessment of the experiences made with the different RES-E promotion schemes in the Member States. However, in this communication the Commission has not made use of its right to propose a CSF and instead decided to reassess the experiences in 2007. Thus, no specific design for a CSF has been officially proposed yet. In this context, the PERSEUS-RES-E approach offers the possibility to compare different design options and their consequences.

assumed that the value of renewable electricity generation is underestimated. As the interrelations with other economic sectors are not accounted for, the chosen sector-specific model type implies further limitations regarding the economic analysis of electricity production from renewable sources. These include e.g. the effects on the number of jobs created or lost in various industry branches[202]. Also other external effects of energy supply, with the exception of CO_2 emissions, are not accounted for in the applied methodology.

10.2 Conclusions from the model calculations

10.2.1 Evolution of the European electricity system and the market for CO_2 emission certificates

Model calculations reveal that the general long-term development of the European electricity system structure depends crucially on CO_2 emission restrictions and fossil fuel price developments.

The increasing stringency of CO_2 emission limitations over the modelled time horizon - both relatively due to the rising power demand, and also absolutely due to further decreasing emission rights - leads to a fundamental restructuring of the electricity sector especially in countries with a very carbon intensive power sector. In the first place a growing economic attractivity of less CO_2 intensive conventional conversion technologies, especially of natural gas combined-cycle power plants as the dominating expansion option in most European countries can be observed. These plants are not only commissioned more frequently, but their capacity is also utilised at higher full-load hours, whereas, without CO_2 restrictions, they would be an economically inferior choice behind coal and lignite fired power plants.

Due to security concerns and the unsettled problem of nuclear waste disposal, nuclear power use is the subject of controversial discussions in the European Union. Without CO_2 emission limitations, nuclear power would not be expanded any further. However, as it allows a practically CO_2 free power generation model results under emission constraints indicate an increased use of this technology in countries where its expansion is not restricted (France, Finland, Great Britain, Poland, the Czech Republic and Slovakia). Model results indicate that the phase-out of existing nuclear capacities in Germany is compensated by an intensified use of natural gas and by significantly increased electricity imports.

Although fuel price elasticities are not considered endogenously in the model, the effect of fuel price variations can be analysed in the form of fuel price scenarios. This is done for natural gas, which is the most attractive conventional fuel option in terms

[202] In terms of created jobs, positive effects can be observed due to the manufacturing, operation and maintenance of renewable energy conversion plants (cf. e.g. [BMU 2005]). However, the long term net effects are still disputed. In this context [Pfaffenberger et al. 2003] suggest for Germany that the financial resources bound by the remuneration of renewable electricity could cause comparable negative employment impacts in the long term.

of CO_2 emission mitigation and which also shows the largest price variations. Increasing gas prices lead to higher marginal costs of CO_2 reduction and a growing attractivity of nuclear power in countries pursuing this option. Moreover, an earlier replacement of old coal fired capacities by new, more efficient ones is observed.

10.2.2 Renewable electricity use under different framework conditions

Despite relatively stringent CO_2 emission allowance restrictions in the reference scenario, renewable electricity use is hardly extended beyond the installed capacities in the base year. A significant additional renewable electricity use is only triggered by an extreme gas price increase of 75%. However, even until 2020 the achieved increase in this case is smaller than would be necessary to fulfil the 2010 targets.

When mandatory renewable electricity targets are introduced, the results indicate the theoretically most efficient distribution among the technologies and countries. The most important renewable energy carriers developed throughout the EU in addition to the already existing installations are wind and biomass potentials. An ambitious renewable electricity target in 2020 and limited expansion rates also lead to the use of more expensive renewable energy potentials. However, the most expensive technologies like solar thermal or photovoltaic electricity generation are only extended if appropriate financial incentives or technology-specific quotas are applied.

A continuation of the financial incentives beyond 2003 and under the idealised assumption that the quota based systems will be 100% successful, model results indicate that slightly more than the 2010 renewable electricity target of 22% will be achieved on an EU-level. Although some countries fail to reach their national targets, the missing production is compensated by more production in other countries. However, the incentives do not allow to reach the ambitious target of 33% renewable electricity in 2020. Although a further expansion of renewable electricity takes place beyond 2010, a rising total electricity demand limits the renewable share to 23.8% in 2020.

In terms of additional costs quota based incentive schemes show a relative advantage over price based mechanisms. However, this theoretical advantage of quota systems is likely to be at least partially relativised in practice. This applies to their efficiency (higher transaction costs) as well as to their effectiveness (higher risks for investors) in comparison to price-based mechanisms. Generally, the utilisation of renewable potentials is subject to various limiting factors in practice, which can not be considered in the model. These factors can be of a concrete technical or organisatorial nature, such as a weak grid or the denial of a permission. But also the perceived investment risk as a less concrete issue can prevent the schemes from being effective (cf. also chapter 3.5).

Generally, model results show that support mechanisms are necessary to achieve significant penetrations of renewable electricity. In principle the competitiveness of renewable electricity generation can be enhanced and the need for support measures reduced by policy measures that internalise further external costs.

10.2.3 Interactions between renewable and conventional electricity generation and the CO_2 certificate market

For the medium to long term the results of the optimising power system model PERSEUS-RES-E show which conventional technologies are substituted by renewable electricity generation. Especially in countries without the possibility to expand the utilisation of nuclear energy, renewable electricity generation limits the need for the construction and use of natural gas fired combined-cycle power plants. Partially, also hard coal power plants are replaced. Where new nuclear capacities may be constructed, the use of CO_2 free renewable electricity primarily substitutes an according increase of nuclear power plant capacities and their generation.

Thus, the avoided full costs of conventional power generation in the medium to long term are significantly higher than in the short term, where capacity additions are not necessary and only the short-term marginal costs are saved. In other words, the changing cost structure of electricity generation with increasing prices for conventional energy carriers and increasingly stringent CO_2 emission limitations makes the use of renewable electricity economically more attractive, although most of the potentials would still not be competitive without additional incentives.

The trend observed in the PERSEUS-RES-E model to use primarily increasing amounts of natural gas to comply with future climate change mitigation obligations is beneficial for the compatibility of the conventional power plant portfolio with fluctuating feed-in from wind power. Thus, a positive correlation between the emission reduction efforts induced by the EU-ETS in conventional power production and the ability of the power system to level out wind fluctuations is observed. This conclusion derived particularly for Germany and Spain can be transferred to other countries with fossil-dominated electricity generation. However, the energetically most efficient gas fired combined-cycle power plants can only provide reserves to a limited degree. Thus, more flexible but less efficient gas turbines need to be installed in addition. Due to their lower electrical efficiency they are not used for regular power production, but act as stand-by reserve capacities. Partially, also the decommissioning of existing coal and oil fired capacities is postponed in order to help fulfil the reserve requirements. Compared to fossil dominated electricity systems the demand for additional flexible natural gas fired capacities is higher in nuclear-dominated systems, as e.g. in France. The total demand for additional reserve capacities in the EU-15 reaches 16.2 GW in 2010 and 50.6 GW in 2020.

The costs for providing additional reserves and for balancing wind fluctuations are determined using the coupled modelling approach with PERSEUS-RES-E and Aeolius. In 2010 the average costs for the provision of additional reserve capacities throughout the EU-15 amount to 0.25 cent/kWh of wind energy. In 2020 this value rises to 0.44 cent/kWh. The actual balancing of the fluctuations causes costs up to

0.22 cent/kWh of wind energy in Germany and 0.25 cent/kWh in Spain. The additional emissions caused by the balancing of wind fluctuations in Germany and Spain are relatively small and do not exceed a maximum value of 32 gCO_2 /kWh of wind energy.

An increased use of practically CO_2 free renewable electricity, regardless whether triggered by quantity- or price-based incentives, reduces the scarcity of the new production factor CO_2 emission allowances. As a consequence, significantly lower marginal cost for CO_2 emission reductions result in the scenarios with ambitious renewable electricity utilisation. Reductions of up to 34% or 8.7 €/tCO_2 compared to the value in the reference scenario occur in 2020 and 19% or 3.9 €/tCO_2 in 2010. Still, the use of renewable electricity is less efficient than other CO_2 mitigation options, e.g. a fuel switch. The economic burdening of European electricity consumers as a consequence of the financial incentives and renewable quota obligations, respectively, is thus higher than with conventional emission reduction options. However, although frequently observed in comparative assessments of the benefits of renewable electricity, the overall economic efficiency and benefits for sustainability of renewable electricity generation can and should not be reduced merely to CO_2 reduction, as this criterion alone is no adequate basis of comparison. Instead, a significantly higher economic value would have to be assigned to renewable power generation if also other external effects were considered (cf. chapter 3.2.1). Another major benefit of renewable energy use not accounted for is their contribution to a reduction of the fossil energy carrier import dependency. A fulfilment of the ambitious renewable targets in the year 2020 can substitute 443 TWh of natural gas fired power production across the EU-15. Furthermore, up to 284 TWh of nuclear power generation can be substituted. At the same time, the utilisation of coal and lignite, which are less critical in terms of fuel supply security, can be increased by 89 TWh and 17 TWh, respectively, compared to the reference scenario. In order to make the political discussion about the future role of renewable energy as objective as possible it is thus important that the aims of renewable electricity use are precisely formulated in this discussion.

10.3 Outlook: Further research considerations and possibilites for future model developments

Both components of the hybrid modelling approach, the PERSEUS-RES-E optimisation model and the AEOLIUS simulation model, can be further applied to a variety of research questions, either separately or in combination. Some of these applications can be realised more or less directly with the existing models, others only after a preliminary adaptation of the data basis and the system boundaries, as well as through a further development of the model methodologies. Possible pathways for the further development of both models shall be highligted in the following.

10.3.1 Amendments to the model data basis and expansion of system boundaries

The developed PERSEUS-RES-E model is currently focussed on the electricity market developments in the EU-15, taking into account several important neighbouring regions. A trade-off between the geographical scope, the temporal resolution and the technical level of detail possible to be considered in the model has been necessary due to the limits of currently available computing power. In order to achieve acceptable calculation times, the size of the mathematical problem must be confined. Various parts of the system are thus modelled in an aggregated way. Assuming that the future development of hardware (computing capacities) and software (improved mathematical algorithms) will allow larger problems to be treated, several options for the expansion of the existing PERSEUS-RES-E model can be proposed.

In order to account for the fact that also the ten new EU-Member States have targets for the utilisation of renewable electricity, it is desirable to expand the model to cover the EU-25 at the same level of detail, including the conventional power system and cost-potential data for renewable electricity resources. Another consequential model amendment is the inclusion of the available potentials and different conversion technologies for the utilisation of renewable heat. Furthermore, possible future obligations and incentive schemes for renewable heat use could be integrated analogously to those specified for renewable electricity. Similarly, further pollutants such as SO_x and NO_x could be integrated into the model, which would enable a quantitative assessment of the achievable emission savings from the implementation of renewable technologies.

Generally, the compliance with targets for renewable electricity use, which are specified in relation to electricity consumption in the RES-E Directive, can be facilitated by implementing complementary measures of demand side efficiency. In this case, less renewable electricity needs to be produced to comply with the given target. Like the use of renewable electricity, DSM efforts will also reduce the total amount of energy carrier imports. So called white certificates for energy savings on the demand side can also be integrated into the model (cf. [Rentz et al. 2006] and [Möst 2006]), next to the modelling of trading schemes for CO_2 emission allowances and green certificates. This allows to assess the interactions between these three environmental policy instruments, and to identify possible synergetic effects. Especially the complementarity of energy end-use efficiency and renewable energy use could be quantitatively assessed in order to derive cost-optimised combinations of obligations under both schemes.

An important reason for an increased utilisation of renewable energy carriers is their indigenous availability, which helps to reduce the dependence on energy carrier imports and possible future price variations. In this context, an endogenous modelling of conventional fuel resources with a detailed representation of transboundary energy carrier transports, as e.g. of natural gas supply (cf. [Perlwitz et al. 2005]), would allow to directly quantify the effects of renewable energy use on import dependence.

The use of renewable energy carriers for electricity generation is regarded as a contribution towards a sustainable development within the electricity sector. It could thus be integrated into an extended, more comprehensive cost-based analysis, including external costs and sustainability indicators, similar to the goal programming approach for the French electricity sector described by [Fleury 2005].

Provided that sufficiently detailed wind speed or wind power time series of representative wind park sites are available, the AEOLIUS model can also be easily adapted and applied to further countries. Especially countries with a high wind energy potential are interesting in this context, as e.g. France or the United Kingdom.

Further, the methodological approach of AEOLIUS could be amended in order to account for an improved simulation of wind power prediction methods and errors (e.g. ARMA[203]). Also, its technological and regional diversification could be increased, especially with a view on distributed generation and demand side measures. In an increasingly decentralised power generation system, the system dynamics approach of AEOLIUS can thus also be a suitable basis for an expanded analysis that aims to take into account the feedback effects between power generation, storage and demand. In this context, a more detailed modelling of the electricity grid as the interlinking element would be an interesting option.

10.3.2 Consideration of new technical solutions and technological progress

Concerning possible future innovation processes and technological developments, the described modelling of technologies in PERSEUS-RES-E and AEOLIUS can be considered as inherently conservative. Solutions in the stage of research and development, which are technologically not yet mature to be applied on a larger scale, are not considered in the models. Nevertheless, the existing models can easily be amended to take into account new technologies in the power plant sector, as e.g. CO_2 capture and storage, or hydrogen-based technologies for power generation or the intermediate storage of electricity.

While technological breakthroughs are hardly predictable ex ante, improvements of existing technologies can be methodologically represented as learning curve effects in energy system models[204]. In principle, this allows for temporally variable cost-potential curves, but only by introducing non-linearities due to the time dependence of the potentials and costs. A linearization with a limited number of binary variables would be possible for conventional technologies, as the availability of capacities for each technology on the market can be regarded as practically unlimited and the cost characteristics as relatively uniform. Contrarily, the differentiations necessary to model the dynamic utilisation efficiency of cost-potentials of renewable energy

[203] Auto-regressive moving average.

[204] See e.g. [Vögele 2005] and [Remme et al. 2005].

carriers would result in a high number of binary variables, making a linearisation of the temporally variable utilisation efficiency unreasonable with regard to the model size and the resulting calculation times.

10.3.3 Geographical focus and technology focus

Analogously to the situation in the renewable electricity industry a trend to decentralisation is also observable in the conventional power sector. This includes technologies like decentralised combined heat and power plants in district heating networks. Increased of the efficiencies of new combined heat and power technologies like fuel cells or micro gas turbines could make decentralisation even more attractive. Similar to the distributed generation of renewable electricity, this will have impacts on the load flows in the grid. On the other hand, new possibilities for the control of load flows and generation will emerge from an integrated utilisation of centralised and decentralised generation, electricity storage as well as demand side management. The latter also involves approaches for load-shedding as e.g. described in [Auer et al. 2005] or intelligent pricing approaches [Eßer et al. 2006].

For the modelling of such an increasingly decentralised electricity system, the described modelling approach could be adapted to achieve greater regional and technological detail. For example, individual blocks of power plants or renewable capacities, as e.g. large wind parks, and their locations in relation to the demand centres, could be taken into account in the model, along with an improved representation of the electricity grid. Furthermore, technologies that can act complementarily to the effects of wind power fluctuations, especially hydro power regimes, could be modelled in greater detail (cf. [Möst 2006], [Vogstad 2004]).

Mixed-integer or stochastic programming approaches would allow for a more realistic and detailed modelling in this context, but require considerably more computing power than the purely linear programming approach. With regard to computing power and calculation times, a trade-off will thus be necessary between the modelling level of detail (technologies, grid, temporal resolution) and the geographical scope of the model. For example, the geographical scope of the analysis could be limited in order to allow for a more detailed modelling of other issues. This could mean that instead of an interregional European model, only a limited number of regions can be modelled in such detail. However, it would be possible to take into account interregional aspects exogenously in such a model, e.g. by adequately parameterised external electricity purchasing options.

Alternatively or in addition, AEOLIUS could be amended to integrate the above issues. Especially a more detailed modelling of the distribution of generation and demand within a region, i.e. the representation of the electricity grid by a larger number of nodes, would be desirable (see also section 10.3.1 above).

10.3.4 Coupling with methodologically different modelling approaches

Similarly to the coupling of the long-term optimisation model with a temporally higher resolved short-term simulation model realised in this work, couplings with models based on other methodological approaches could be realised. This includes e.g. macroeconomic models[205] or game theoretic approaches, but also GIS-based applications. Both hard and soft links can be applied to achieve these possible couplings. In this context, the technology-focussed sectoral model PERSEUS-RES-E can be used to determine the developments of key electricity sector variables on a fundamental basis. The results, e.g. the marginal costs of power generation and CO_2 emission reductions, or the costs for the achievement of renewable electricity targets, can subsequently be used as input parameters for a further model-based analysis. For example, in the case of a macroeconomic model with a higher level of aggregation, the effects of endogenous developments in the sectoral PERSEUS-RES-E model on other economic sectors can be analysed[206]. Conventional power generation as well as RES-E use have impacts beyond the electricity sector, which can be quantified by models that take into account intersectoral relationships, as e.g. given in the manufacturing of power plant components, operation and maintenance, or job effects. Vice versa, the feedback effects from these economic sectors on the modelled sectors in the sectoral model can be taken into account in a scenario analysis by specifying the appropriate model parameters.

[205] For examples of energy system models and macro-economic modelling approaches see e.g. [Briem et al. 2003], [MEX IV 2004].

[206] Such an analysis with results from the PERSEUS-RES-E model as an input and a special focus on the effects of renewable electricity use has been carried out for the French power sector and its interactions with other sectors of the French economy (cf. [Pfaffenberger et al. 2005]).

11 Summary

Deregulation and liberalisation efforts have led to an opening of national electricity markets. Nevertheless, the sector framework is continuously influenced by political requirements and regulations, such as the limitation of allowed CO_2 emissions or the nuclear phase-out policy in Germany. Of special relevance in the context of this work is the stipulation of targets for the use of renewable energy carriers for electricity generation. For political decision makers the need arises to assess the economic and environmental effects of their decisions and to adjust interacting regulations in the form of a consistent, effective and efficient policy framework. Within the long-term planning of energy utilities the investment and production planning process is especially affected. The complexity of this task increases in a liberalised market, and it is subject to significant uncertainties concerning the evolution of key influencing parameters on the investment planning process, as e.g. the development of fuel prices and CO_2 emission constraints.

It is the objective of this work to develop a methodology for the quantitative assessment of the long-term role of renewable electricity production under varying framework conditions within the liberalised European electricity market, and to apply this methodology to the EU-15 Member States. Such a methodology has to be appropriately designed to enable a detailed representation of all relevant resources and technologies for renewable electricity generation in the framework of a strategic capacity expansion planning approach. As a consequence of the liberalisation process the international context becomes more important in European electricity markets. In order to adequately reflect these increasingly multi-regional market structures, the electricity sectors of relevant neighbouring European states along with the effects of interregional power exchange need to be included in the analysis. Moreover, intertemporal relations between investment and production decisions must be taken into account, which is realised in an integrated system expansion and production planning approach. Next to the technological, temporal, and regional differentiation of the realised renewable electricity production under different framework conditions, information needs to be derived on the influence that the use of renewable electricity has on future price developments in the interdependent markets for electricity and CO_2 emission certificates. With increasing shares of renewable electricity generated from fluctuating sources such as wind energy, the methodology also shall be able to account for the interactions with conventional electricity generation and the security of supply.

The core element of this work is the development and application of a hybrid modelling approach, which consists of two individual, yet complementary, models coupled via a so called soft link. On the one hand, this is the long-term strategic energy system optimisation model PERSEUS-RES-E, and on the other hand the heuristic simulation model AEOLIUS for power plant scheduling on a shorter time scale, but with a higher temporal resolution.

The PERSEUS-RES-E bottom-up model of the European electricity sector is based on a multiperiodic, linear programming approach, which allows to analyse the long-term developments of the European electricity markets. It contains existing power plants and future expansion options with improved technological and economic parameters, represented by a total of more than 1,400 aggregated technology classes. Next to the representation of competing power generation technologies in each of the modelled 21 European countries, represented by 25 regions, the model allows to take into account the interregional power exchange as well as the trading of CO_2-certificates.

Further, the model development and the methodological amendments allow for a much more detailed representation of renewable electricity sources. This includes the integration of 15 renewable energy conversion technologies in each country of the EU-15 with their available resources and the corresponding costs into the model data-base, modelled as so called cost-resource curves. These realisable renewable potentials are represented in PERSEUS-RES-E by about 1,500 newly implemented energy conversion units and the same number of processes with corresponding technical and economic parameters.

In the energy system optimisation realised with the developed long-term modelling approach the cost-optimised development of the electricity sector in the modelled regions is determined for a time horizon of 20 years. The optimisation criterion used is the minimisation of relevant system expenditures. Due to restrictions of the calculation time it is not possible to model e.g. each hour during this time horizon separately. Instead, characteristic years are chosen, which each represent five years of the time horizon in the developed model. The load profile of each representative year is modelled using characteristic days, with the demand profile for power and heat on these characteristic days as the driving force of the model. Technical, economic and ecological restrictions are integrated into the model in a suitable manner, in order to account for the characteristic system properties of energy supply systems in reality. In order to account for an increased utilisation of fluctuating renewable energy carriers, i.e. especially wind power, requirements for reserve capacities are derived and integrated as additional constraints into the investment and production planning model. Furthermore, emissions and costs that occur in the conventional power sector due to the necessary reserve capacities and the balancing of fluctuations are also integrated into the model.

For the calculation of the above fluctuation-based effects the dynamic simulation model AEOLIUS has been developed. With the electricity demand as the driving force, a so called merit order power plant scheduling is carried out for time horizons of one year, based on heuristic methods. Hourly average wind power feed-in values, which are derived from actual wind speed measurements at characteristic sites, are used to determine the residual load to be covered by the conventional capacities. The operation of the conventional power plants, which have to provide reserve capacities and control power, is modelled considering technical properties like load change capabilities, start-up losses, load-dependent efficiencies, availabilities, revisions, etc.

AEOLIUS is applied in two possible ways to the German and Spanish power sectors, which are represented by aggregated typical power plant classes. Firstly, the consequences of increased wind power integration into a given, static power plant portfolio are assessed. Simulations in this case show that wind energy replaces conventional electricity mainly from base load and intermediate load. Efficiency losses due to additional power plant start-ups, load changes, and partial load operation for the provision of spinning reserve limit the theoretically possible cost and emission savings in the conventional plant portfolio. Secondly, using the model results of the long term PERSEUS-RES-E model, also future power sector configurations are analysed. In this case with a dynamic power plant portfolio, AEOLIUS is used to assess the resulting inefficiencies in the future conventional generation mix resulting from the future amount of wind energy in the generation system. This information can then be integrated into a new PERSEUS-RES-E calculation. A direct determination of these effects in PERSEUS-RES-E would not be possible due to its aggregated temporal resolution with typical days.

As a major accomplishment the chosen integrative modelling approach combines a highly detailed representation of the spatial distribution and cost structure of renewable electricity potentials across the EU-15 with the inter-regional and intertemporal aspects of electricity sector expansion planning. Moreover, the linkage between the markets for electricity and CO_2 emission allowances is endogenously taken into account. Finally, the hybrid approach allows to consider the various time scales on which the interactions of renewable electricity with the conventional part of the power system occur.

The optimisation results show that without any financial incentives the current and expected future cost situation in the electricity sector would not allow renewable sources of electricity to become a favourable economic solution, even under a relatively stringent CO_2 reduction path. Only at very high gas prices a limited amount of relatively inexpensive wind and biomass potentials becomes attractive in later periods. However, the achieved penetration in 2020 in this case is still not sufficient to fulfil the EU renewable targets specified for 2010. A significant and sustained increase of the share of renewable energy carriers in electricity generation beyond the 2010 renewable targets is thus only feasible with the specification of longer term targets and according support mechanisms.

Provided that other impeding framework conditions such as grid access, administrative barriers, etc. are overcome, the results indicate that the current price-based promotion schemes provide sufficient incentives to fulfill the European renewable electricity target in 2010. However, the incentives in some countries are not high enough to reach the national target, as e.g. in Portugal and France. On the other hand, an overcompliance is achieved in countries like Germany and Denmark.

The marginal costs of compliance with a national or European target without any financial incentives can be interpreted as a lower bound for the expected price of green certificates under the premise of a perfect market. They vary between 24.7 cent/kWh in 2010 and 57.6 cent/kWh of renewable electricity produced in 2020, provided that no technology specific targets, but a general target is fixed. The corresponding average costs per kWh of renewable generation to achieve the given European targets amount to more moderate values of 8.0 cent/kWh in 2010 and 9.1 cent/kWh in 2020. When levelised on the total amount of power produced, the maximum average additional costs incurred by RES-E use in the EU-15 range from 0.59 cent to 1.93 cent per kWh of total electricity production in 2020. Although more expensive in total, a politically induced introduction of renewable electricity reduces the scarcity of CO_2 emission allowances and lowers the marginal costs of CO_2 reduction up to 34% in 2020, when ambitious targets are specified for this year. Despite the higher overall costs, a diversification of the energy resource base by RES-E use is observed, as primarily natural gas and nuclear fuels are replaced. Although not economically valued in the electricity market, this is a bonus in terms of a weakened increase of the energy import dependency.

Further, the efficiency losses and the costs induced by conventional reserve capacities and balancing power for wind energy expansion, including the necessary grid expansions, are relatively small compared to the overall additional costs due to the generally higher generation costs of renewable technologies. Among these technologies, on-shore and off-shore wind power together with biogenous resources and the remaining hydro electric potentials are among the economically most favourable ones across the EU-15.

Thus, the described modelling approach allows to derive cost-optimised, country- and technology-specific allocations of RES-E shares for different RES-E targets and under varying constellations of framework conditions. Also, the degree of compliance with national and EU-wide targets that can be expected at the current or any other given constellation of national financial incentives can be assessed. This allows to derive country- and technology-specific minimum incentive levels, which are necessary to comply with a given national or EU-wide renewable electricity target.

More generally, it can be concluded that the approach allows to assess electricity sector market developments under the interrelated effects of design options for various policy instruments and other framework conditions. This does not only concern the support of renewable electricity utilisation, but also e.g. the field of emission reduction policies. Further, the developed model instrument can easily be adapted to take into account other environmental policy measures, such as energy conservation and efficiency measures. The results of the analysis illustrate that the implemented modelling approach is a sophisticated and versatile tool, both for utilities to analyse future market developments, and also for policy planners in order to design effective and efficient policy measures, especially for renewable electricity support.

Abbreviations

Abbreviation	**Explanation**
ARMA	Auto-regressive moving average
CER	Certified Emission Reduction
CHP	Combined Heat and Power
CSF	Community Support Framework
DSM	Demand Side Manangement
EEX	European Energy Exchange
EPR	European Pressurized Water Reactor
ERU	Emission Reduction Unit
ETS	Emission Trading Scheme
ETSO	European Transmission System Operators
EUA	EU-Allowance
FIT	Feed-in tariff
GCT	Green Certificate Trading
HDR / HFR	Hot Dry Rock / Hot Fractured Rock
MSW	Municipal Solid Waste
NTC	Net Transfer Capacity
PV	Photovoltaics
REFIT	Renewable Energy Feed-In Tariff
RES	Renewable energy sources
RES-E	Renewable energy sources for electricity generation
RES-H	Renewable energy sources for heat generation
SMC	System marginal costs
TGC	Tradable Green Certificate
TSO	Transmission System Operator
UCTE	Union for the Coordination of Transmission of Electricity

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