October 2003 ECN-C--03-082

RENEWABLE ELECTRICITY MARKET DEVELOPMENTS IN THE EUROPEAN UNION

Final report of the ADMIRE REBUS project

M.A. Uyterlinde
B.W. Daniels
M. de Noord
H.J. de Vries
C. de Zoeten - Dartenset
ECN

K. Skytte
P. Meibom
Risø

D. Lescot
Observer

T. Hoffmann
M. Stronzik
ZEW

M. Gual
P. del Rio
F. Hernández
CSIC

Acknowledgement

Support of the European Commission

The ADMIRE REBUS project is partially funded by DG TREN (Energy & Transport) of the European Commission under the ALTENER programme; Contract no. 4.1030/Z/01-003/2001. ECN has registered the project under no. 77434. This document or any other document produced within the ADMIRE REBUS project does not represent the opinion of the European Commission. Neither the European Commission, nor any person acting on behalf of the Commission, is responsible for the use that might be made of the information arising from the ADMIRE REBUS project.

ADMIRE REBUS project partners:

- ECN Policy Studies - NL (co-ordinator)
- RISOE, Denmark
- ZEW, Germany
- CSIC, Spain
- Observer, France
- SERVEN, Italy (until December 2002).

Further information:

Ms. Martine Uyterlinde
ECN Policy Studies
P.O. Box 1
1755 ZG Petten
The Netherlands
Tel: (+31) 224 56 4369/4347
Fax: (+31) 224 56 8338
E-mail: uyterlinde@ecn.nl
Internet: www.admire-rebus.net

Abstract

Which countries offer the best markets for renewables? Are present support policies sufficient to meet the EU renewables target for 2010? Which renewable technologies will have the largest growth in the present decade? The ADMIRE REBUS project has addressed these questions by giving an outlook on the future of electricity from renewable energy sources. The ADMIRE REBUS project team has analysed the market barriers, support policies and potentials for renewable electricity production in Europe. For these analyses a new tool was developed that simulates the development of the European renewable electricity market under different policy scenarios.

The report starts with describing the approach and key assumptions used in the analysis. Next, an overview is provided of EU legislation and different support policies for renewable energy. After a brief overview of the different challenges that an investor faces when investing in renewable energy technologies with respect to lead times, risks and transaction costs, several policy scenarios for the future are discussed. Next, the report presents ADMIRE REBUS model analyses of different policy strategies for meeting the targets stated in the EU Renewables Directive. The report continues the analysis of model results with presenting prospects for individual technologies and market prices under different scenarios. Next, case studies are presented for four different EU Member States. The analysis results are put into perspective by a sensitivity analysis. Finally, conclusions are drawn and recommendations are formulated based on the above.

CONTENTS

LIST OF TABLES

LIST OF FIGURES

GLOSSARY

Additional production costs	Extra cost to end users and the public sector over and above the cost of the energy carrier concerned or its closest substitute (grid electricity, gasoline, etc.) if no RE policy support would have been in place
Eligible	1) Qualifying for RE support 2) Counting for the RE policy target concerned
EU	European Union
FIT system	Feed-in tariffs system: a RES-E direct market support system, in which distinct regulated preferential tariffs have to be paid to technology-specific categories of RES-E generators for feeding their electricity directly into the public grid concerned
GJ	Giga (10^9) joule
GO	Guarantee of origin: a unique proof of the source of a certain quantity (e.g., 1 MWh) of RES-E electricity
MS	Member State
GWh	Giga (10^9) watt-hour
PV	Photovoltaics: technology by which direct and diffuse sunlight absorbed by solar panels, is converted into electricity
RE	Renewable energy
REC	Renewables-based electricity certificate: a unique proof that a certain quantity of electricity (e.g., 1 MWh) has been generated by eligible renewables-based electricity; refers to 'generic' RES-E, generated by 'modestly non-competitive technologies'
RES-E	Renewables-based electricity; renewably-generated electricity
RET	Renewable energy technology
RGP	Required Green Price: the net price an investor requires from the green market in order to achieve a zero Net Present Value.
RPS	Renewables portfolio standard: a RES-E support system, in which the regulator sets a minimum share of total electricity supply or demand in a jurisdiction to be sourced from eligible RES-E sources
Total expenditures	Total government RES-E market support and end-user expenditures in addition to expenditures for electricity in absence of RES-E support mechanisms

EXECUTIVE SUMMARY

Which countries offer the best markets for renewables? Are present support policies sufficient to meet the EU renewables target for 2010? Which renewable technologies will have the largest growth in the present decade? The ADMIRE REBUS project has addressed these questions by giving an outlook on the future of electricity from renewable energy sources. The ADMIRE REBUS project team has analysed the market barriers, support policies and potentials for renewable electricity production in Europe. For these analyses a new tool was developed that simulates the development of the European renewable electricity market under different policy scenarios.

Policy context for renewable electricity

For many years, renewable energy technologies have received financial and political support within the European Union and its Member States. The reasons have differed, ranging from security of supply and local employment to emission reduction. Due to this diversity of policy objectives and ambitions, the support schemes also differed among countries and technologies. Figure S.1 illustrates the different policy instruments currently in use in EU Member States for direct market support and investment support. In general, a trend can be observed towards two main instruments, feed-in tariffs and quota obligations supported by a system of tradable green certificates (TGC).

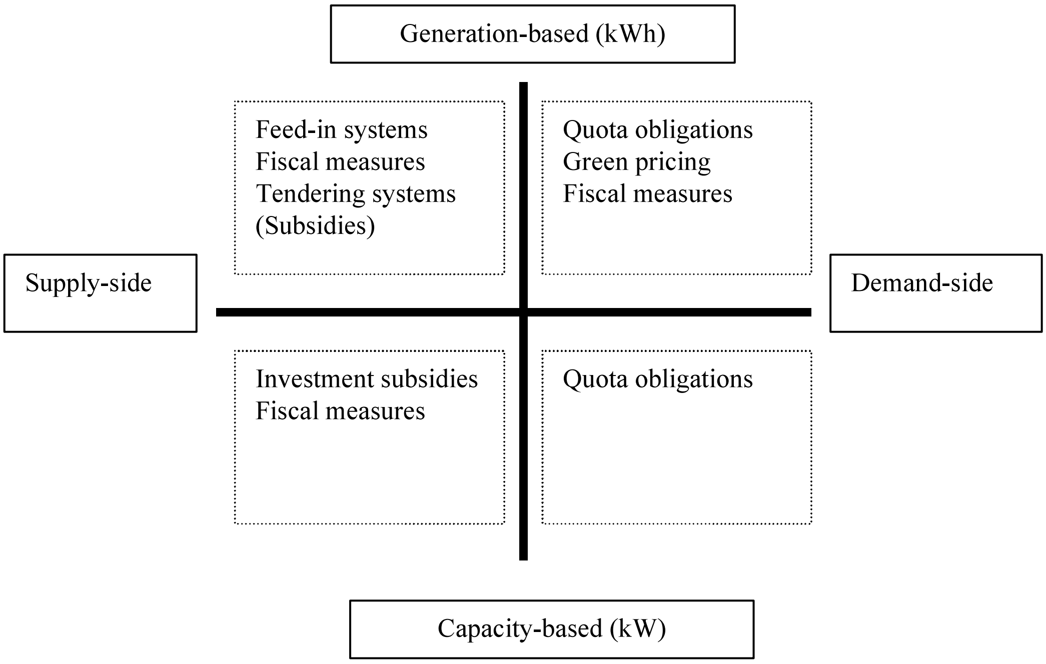


Figure S.1 *Types of policy instruments used for supporting renewable electricity*

An important milestone for renewable electricity policy was the adoption in 2001 of the Renewables Directive (2001/77/EC), which has set indicative national targets, measured as percentages of the total gross electricity consumption. The overall target for EU is 22.1% in 2010 compared with a share of 14% in 1997.

Furthermore, the policy context for renewable electricity is changing due to the liberalisation of the energy markets in the EU, leading to an increasingly important role of international trade. In line with these developments, the Renewables Directive announces an evaluation of the coexistence of different support mechanisms, including their cost effectiveness, in relation to the achievement of the national indicative targets. This evaluation is scheduled for the end of 2005, and can be accompanied by a proposal on harmonisation of the support schemes in the EU.

Approach
The ADMIRE-REBUS model explores the development of the EU green electricity market, and provides insight in this developing market to the investors in renewable capacity. The current EU renewable electricity market shows a variety of institutional settings that, when interacting on the emerging international market, may cause trade barriers and distortions. International trade of renewable electricity in a non-harmonised market introduces new dependencies of the value of this electricity on the policy conditions of other Member States. In this market in transition, political risks play an increasingly important role for potential investors and other market actors.

The ADMIRE REBUS model is based on a dynamic market simulation in which national RES-E supply curves are matched with policy-based demand curves. The supply and demand curves are constructed as follows.

- Future potentials are estimated for all technology bands within a country, based on a consistent approach, which allows for technology development and learning effects through time. In the model, realisable potentials are used, meaning that all restrictions except economic ones are accounted for.
- An endogenous cost calculation module determines the costs of renewable technologies, using a net present value calculation. This calculation includes all costs and revenues expected over the lifetime of a technology, and thus incorporates the effect of different support policies in a straightforward way. Costs are expressed in terms of the 'Required Green Price', the average minimal green price that the investor has to obtain from the market over the lifetime of the generating plant in order to make the construction of additional green capacity (or the production with existing capacity) attractive.
- Thus, supply curves, based on costs and potentials, are constructed, and their development is simulated through time.
- In parallel, policies acting on the demand side, such as price support of the demand or quota's on consumers or suppliers, are translated into national demand curves.
- Based on technology, market and political risks, a technology and country-specific risk adder to this Required Green Price is calculated.

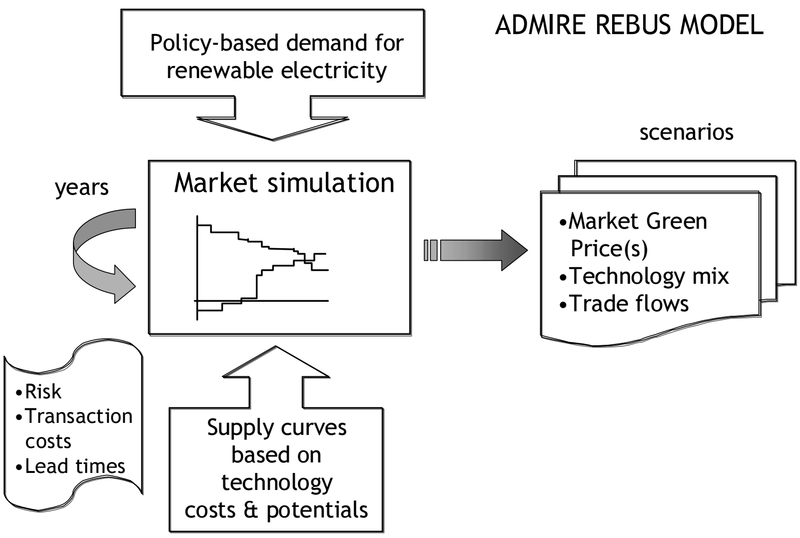


Figure S.2 *Schematic overview of the ADMIRE REBUS model*

The results are calculated in a way that takes into account the discriminative characteristics of some policies, and the ability of producers to choose whether they produce for the domestic market or wish to trade their production. Because of the different levels and conditions of national support schemes, there will not be a single market equilibrium for the EU, but rather different submarkets emerge with local equilibria. This way, the ADMIRE REBUS model calculates the price of tradable green certificates, where appropriate. Note that different TGC prices may exist for different submarkets. Another important model result is the projection of the evolving generating mix per Member State and for the EU, including notably the deployment of renewables-based generating technologies.

The simulations have been done for a time horizon up to 2030, taking account of various other factors complicating investment in renewables, such as risks, transaction costs and delays due to planning and permitting processes. These factors contribute to a realistic simulation of the effectiveness of different policy instruments.

Policy scenarios for the future

Three main scenarios for the future policy and market harmonisation have been developed.

1. *Continuation of present policies* includes currently expected policy developments and assumes that countries that already recognise each other as trading partners (for instance on the basis of reciprocity), will continue to do so, but does not assume further market opening.
2. *Clustered Europe* corresponds to a situation where those countries that are currently using or planning to introduce a quota-based TGC system will open their markets for each other, and will harmonise their frameworks, while other countries will stick to their currently preferred support systems.
3. *Harmonised Europe* provides a reference point by assuming that a harmonised market is established for new capacity, and that the chosen support framework is based on quota obligations (the national targets) in combination with a TGC system. Several variants on this scenario are presented, which differ in the choice of the start year of harmonisation and the length of the transition period until the targets are binding.

The scenarios differ along two dimensions, as illustrated in Figure S.3 The level of co-operation is reflected in the extent to which Member States use international trade in a (partly) harmonised policy context. The ambition level is implicit in the size of the quota or the level of the feed-in tariffs, and differs by country.

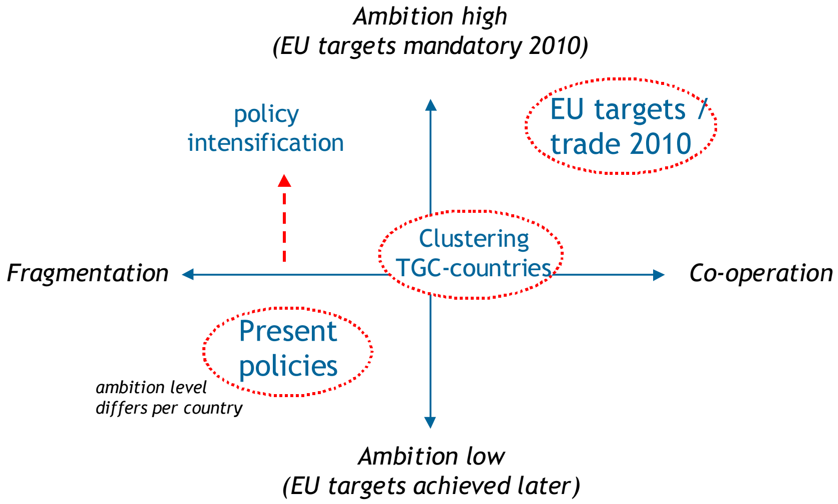


Figure S.3 *Scenario overview*

The future of renewable electricity in Europe

The ADMIRE REBUS tool has been used to analyse the developments in the market for renewable electricity in Europe in the next decade, under different scenarios.

Technology prospects depend on the regulatory framework

Comparing different scenarios, illustrated in Figure S.4, it is clear that achievement of the EU targets will to a large extent rely on wind onshore and biomass, in addition to a stable contribution from (large) hydropower. The development of other technologies is more dependent on the type of policies used and on the ambition level of these policies.

For wind onshore, a large growth is expected under all scenarios. Main countries are the UK, Germany, France and Spain. In the most ambitious scenarios, Sweden becomes the fifth producer of wind-based electricity in the EU. Apparently, the exploitation of the significant onshore wind resource in Sweden requires additional support policies. The use of biomass will increase in general if the policy ambition level increases. Biomass-fired CHPs and co-fired facilities will benefit more from the introduction of a TGC system than other biomass technologies. With respect to the deployment of different biomass resources, agricultural residues and forestry residues show the largest growth.

Although wind offshore has the potential to contribute substantially, it does not meet all expectations. Support levels across the EU appear to be insufficient. Nevertheless, national governments will probably introduce specific policies such as tenders to realise current plans. If offshore wind can only benefit from generic policy support, competition with other renewable sources reduces its possibilities. However, in the most ambitious scenarios, offshore wind energy directly benefits from a higher level of the TGC price, and capacity is installed in Germany, Denmark and the Netherlands. In the years after 2010, market opportunities for offshore wind energy are expected to improve considerably due to ongoing cost reductions caused by learning effects.

The prospects for PV are uncertain - it is the only technology that shows more growth under continuation of present policies than in a scenario assuming the introduction of a TGC market. This means that specific support covering the relatively high cost will remain crucial in the next decade. Under continuation of present policies, PV will mainly be installed in Spain, Portugal, Germany, and Austria. Growth is also expected in France.

The prospects for geothermal electricity also depend on the regulatory framework and associated ambition level. Under continuation of present policies it will hardly grow, but under a TGC system in combination with mandatory targets the EU White Paper target of 1000 MW can be achieved with installations in Italy, Portugal and Greece.

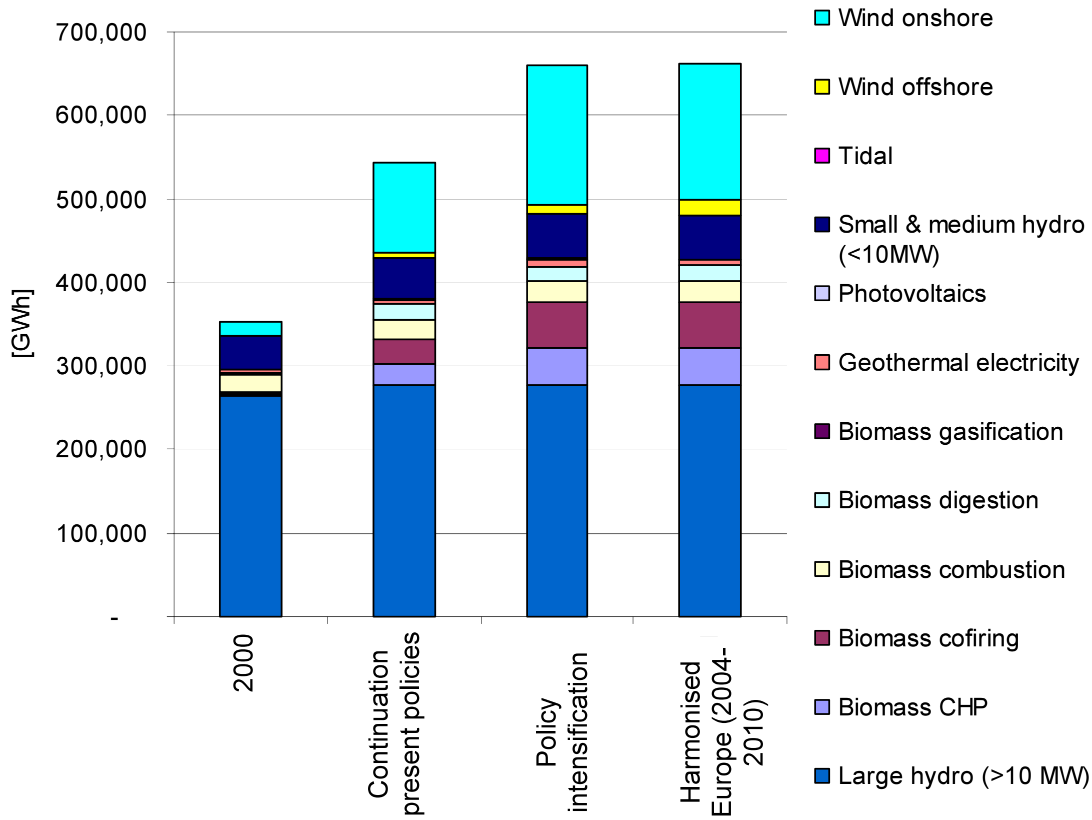


Figure S.4 *EU-15 RES-E technology mix in 2010 under different scenarios*

Long-term renewable electricity price expectations

If a EU market for tradable green certificates emerges, the certificate price directly depends on the level of the demand created in this market, in other words the ambition level of policies translated into quota. Assuming that the quota are based on the EU targets for 2010, the market price is expected to increase rapidly in the transition period up till 2010, when the market is adjusting to the increase in demand level. In this period, TGC prices are expected to be in the range of 5-6 ct/kWh. This price is additional to an average electricity commodity price of 3 ct/kWh in the baseline scenario. In the period beyond 2010, the level of the TGC price is directly dependent on whether new targets are agreed in the EU. If the ambition level does not further increase, and targets will only see a moderate increase in absolute terms as a result of the growth in electricity demand, the TGC price will stabilise at a lower level of 3-4 ct/kWh.

Trade flows

When the market for electricity from renewable resources is opened further for international trade, some countries will be importers of RES-E while others will be exporters. In this respect, the main question is which countries will open their markets and when. In the scenarios involving trade under harmonised quota for all EU countries, the main importers will in 2010 be Spain, Portugal and Italy, while the largest exporters will be Denmark, Germany, UK and Ireland. Beyond 2010, Sweden also becomes and exporting country, which is due to the growth of onshore wind.

Meeting the EU Renewables Directive targets
The ADMIRE REBUS tool has been used to evaluate whether the European and national targets might be reached by applying the existing policy schemes at least until 2010. This analysis is based on the assumption that gross electricity demand will grow according to the forecasts given in the EU Energy Outlook to 2020, the same source that was used when the targets were negotiated.

The results show that only a few Member States - Austria, the Netherlands and the United Kingdom - are likely to reach their targets in 2010 when their present policies are continued. Overall, the EU consumption of renewable electricity would be 17.7% of the total electricity consumption instead of the 22% target - a deficit of almost 120 TWh.

There is a large uncertainty connected to the assumption that countries will continue their present policies. It is likely that in the years to come, they will adapt their policies in the light of the targets. For instance, the Netherlands reaches its target partly through imports from countries not achieving their own target, which hardly seems sustainable. Another special case is Ireland where the current policy is only defined until 2005, and a 'policy gap' in 2005-2010 is the main reason for Irelands non-compliance. Furthermore, the analysis of individual countries demonstrates that not the type of support scheme but rather the way it is implemented and the level of support determine its effectiveness, although the efficiency might differ.

Strategies
Several strategies can help to bridge the gap between target and projected consumption. One strategy is an intensification of current policies. Most countries can achieve their target by increasing their average support level to an equivalent of at most 6 ct/kWh. However, for Spain, Italy, Belgium, Portugal and Luxembourg, costs of this policy intensification will rise to very high levels. This is due to the large growth of installed capacity needed in a relatively short period. Investors in these countries - but also in other Member States - have to face substantial delays caused by administrative barriers and local resistance. Measures aiming at removing implementation barriers can increase the renewable electricity share for the EU as a whole from 17.7% to 19.3%.

The most cost-effective strategy for the EU as a whole would be to introduce international trade in a completely harmonised market combined with mandatory targets for 2010. As a reference point, a scenario has been analysed assuming that trade is facilitated in a TGC market from 2004 on. The results, illustrated in Figure S.5 show that the introduction of international trade is the most cost-effective way of achieving the targets. This is mainly due to comparative advantages - renewables are deployed at those locations where potential is available at the lowest costs. Still, some countries may benefit more than others. For Belgium, Italy, Spain, Portugal, and the Netherlands, importing a certain amount of renewable electricity is much cheaper than completely achieving their target domestically. On the other hand, producers in the UK, Ireland, Denmark, France and Germany can explore new export markets once international trade is introduced. However, other policy goals, such as local employment or environmental considerations can cause governments to prefer (a certain share of) domestic RES-E production above import. Finally, given the fact that the targets are expressed as a share of electricity consumption, measures to reduce electricity demand could considerably save costs.

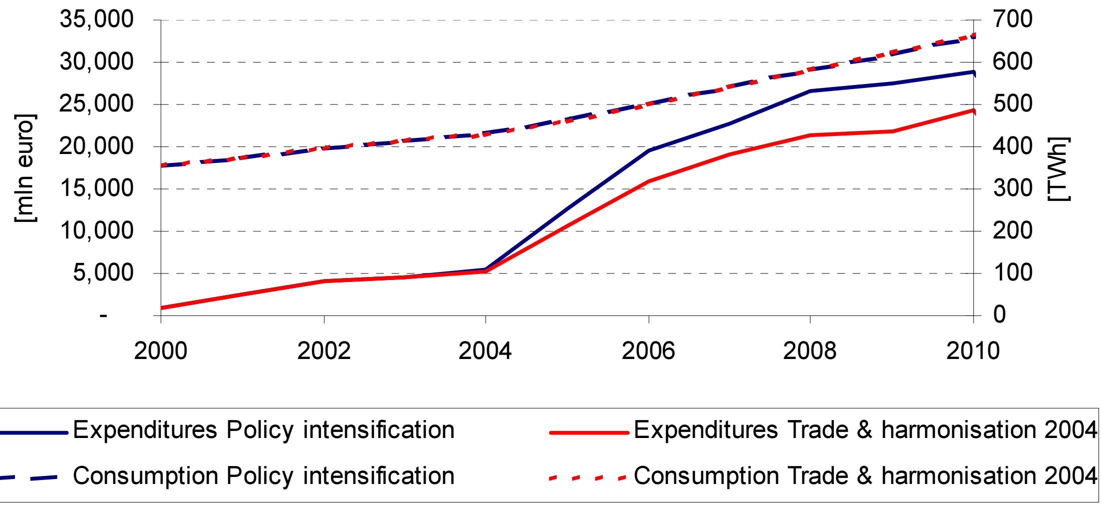


Figure S.5 *Comparing production and total (government and end-user) support expenditures in two scenarios*

Costs of achieving the targets

Compared to a continuation of present policies, the introduction of mandatory targets will significantly increase costs, since it involves a much larger deployment growth in a relatively short period. Total additional production costs estimates for 2010 (excluding surplus revenues) may increase from 4.7 bln € to 10 bln € to achieve 662 TWh instead of 543 TWh, due to a larger share of the more expensive technologies such as offshore wind. In the 'demand side management' scenario where 10% lower electricity demand leads to similarly lower targets, additional production costs are 6.5 bln €.

The total government and end-user expenditures in the EU-15 show the same sensitivity to the level of electricity demand as well as electricity prices. In 2010, the total expenditures related to achieving the indicative targets range on an annual basis from 11 to 29 bln €. The upper value relates to a cost-effective intensification of current support systems to meet national RES-E targets along with modestly increasing prices on electricity wholesale markets (continuation of existing overcapacity in the power sector and a negligible carbon premium). The lower value is based on a scenario of a completely harmonised support system along with substantial price rises on the electricity wholesale markets (sharp reduction in generating overcapacity and a significant carbon premium). The transition from meeting targets with intensification of current support systems to Union-wide harmonisation of RES-E support is projected to reduce total RES-E support expenditure in the EU-15 by at least 4.4 bln € in the year 2010.

Conclusions

In the next decade, the market for renewable electricity will continue to be shaped by policies, because most technologies still depend on financial support in order to survive in a liberalised power market. Therefore the ambition levels of national governments and the EU at large will be the major determining factors for deployment of renewable electricity. These ambition levels can be expressed through different types of support schemes, ranging from feed-in tariffs to quota obligations. Of course, renewable electricity ambition levels are politically determined. Various external factors, such as the introduction of emission trade in 2005, the enlargement of the EU in 2004, and the development of a market for biofuels are expected to have significant impacts on the prospects of renewables in Europe.

The analyses have shown that the introduction of international trade is the most cost-effective way of achieving the targets. However, international trade and harmonisation of the support framework are closely related, but not the same. International trade could also take place between countries using different support schemes, and in fact this is already happening. Therefore, mechanisms to prevent double counting of renewable electricity consumption and double subsidising should be established, for instance based on the Guarantees of Origin that should be implemented in all Member States according to the Renewables Directive. Therefore, although harmonisation is not likely to be introduced - if at all - before 2007-2010, the facilitation of trade is worthwhile to consider in the meantime.

Finally it should be noted that it is not until October 2003 that the European Commission will evaluate to which extent the national governments have transposed the Directive into their national support policies. This would be the most appropriate moment for an evaluation of national efforts. In this sense the current ADMIRE REBUS assessment based on those policies planned or implemented by early 2003, should be regarded preliminary, because Member States still have time to revise their support schemes or to introduce new ones.

Recommendations

22% renewable electricity in the EU by 2010 is achievable, but does require policy intensification in many EU Member States. In this respect, timing is crucial. Due to the effects of lead times and other implementation barriers, a significant increase in renewable electricity production takes a number of years. Sudden increases would entail very high additional costs. In addition, changes in market structure create a lot of uncertainty for market actors, and therefore should be accompanied by a sufficiently long transition period. This is relevant both in the transition from national to international markets, and from the current ambition level to a higher one, and implies that decisions should be taken soon and should cover adequately long time frames.

These considerations lead to the following recommendations.

- National governments should *coordinate* their renewable electricity policies in the light of the Renewables Directive targets. They should provide long-term clarity to market actors on their ambition levels and on the prospects for international trade and harmonisation.
- In this respect, it is also recommended to start setting *targets beyond 2010* to ensure a continued market for renewable electricity and to provide investor security.
- Given the conclusion that international trade is probably a cost effective way of achieving the targets, national governments should look for ways to *facilitate trade* in the current fragmented market. One way could be to use the Guarantees of Origin that are to be established anyway. These could provide a basis for trade among different support schemes.
- Measures must be taken to *reduce implementation barriers* currently causing lead times of several years, thereby increasing the amount of renewable capacity that can be installed in the short run.
- Given the fact that the targets are expressed as a share of consumption, it is stressed that *Demand Side Management* can help achieving renewables targets at acceptable costs.

Further research

The ADMIRE REBUS model has been designed to support policy makers in developing and evaluating renewable electricity policy and to supports investors and other market actors in identifying market opportunities and analysing price developments. The material provided in this report is a selection of the results available to date. ADMIRE REBUS can facilitate analysis on levels of considerable detail, for instance focusing on comparing different policy strategies for individual countries, as illustrated in the country case studies. Notably, the following issues deserve further elaboration:

- The effects of the introduction of an emission trading system on the market opportunities, costs and deployment of renewables.
- The impact of the increased market size with the accession of 10 new Member States.
- A further analysis of the cost effectiveness of different policy instruments.
- A monitoring of the progress of Member States' efforts towards achieving their targets, including the effects of bilateral trading arrangements.

1. INTRODUCTION

1.1 The European renewable electricity market

During the last 30 years, renewable energy technologies have received political and financial support within the EU and its Member States. The motives, favoured policies and measures to promote the deployment of electricity from renewable energy sources (RES-E) have differed largely. After the oil crises, renewable energy was seen as a long-term substitution to fossil fuels as exhaustible resources. Later, promotion of RES-E was supported as a means for an EU-wide security of supply. Another motive was increasing employment opportunities in areas with lower economic growth. Finally, in the light of climate change, RES-E is seen as a good alternative to thermally produced electricity that leads to emissions of greenhouse gasses.

Due to this diversity of policy objectives and ambitions, the support schemes also differed among countries and technologies. In general, a trend can be observed towards two main instruments, feed-in tariffs and quota obligations supported by a system of tradable green certificates (TGC). An important milestone for renewable electricity policy was the adoption in 2001 of the Renewables Directive (2001/77/EC), aiming at facilitating a medium-term significant increase in RES-E within the EU. Furthermore, the policy context for renewable electricity is changing due to the liberalisation of the energy markets in the EU, leading to an increasingly important role of international trade. In line with these developments, the Renewables Directive announces an evaluation of the coexistence of different support mechanisms. This evaluation is scheduled for the end of 2005, and can be accompanied by a proposal on harmonisation of the support schemes in the EU.

If renewable energy technologies have to compete with thermal based power without additional support, new investments may not take place. Apart from the long-term contracts that have supported virtually all existing renewable energy projects, but which will be rare in competitive markets, the market reality is that investors have very short investment horizons. In markets characterised by short-term energy sales and price volatility, investors will prefer technologies with short lead times, low transaction costs and risks. Funds for risky, capital-intensive renewable energy projects will be expensive and difficult to obtain, even if they are expected to produce more cost-effective power than fossil plants over their lifetimes.

These obstacles for investments in RES-E technologies in a competitive environment have to be taken into account. In this context it has been suggested that environmental markets that run parallel to the physical power market should be created. The most recent environmental market design in Europe is a market for tradable green certificates, where renewable energy producers receive an additional payment for their clean power under competitive conditions. The physical power is still sold in the power market where the prices are determined at short-term energy sales, but the price determination at the green certificate market is made based on political targets and might therefore be based on long-term perspectives. This should invite investors to invest in these renewable technologies and, thereby, ensure an increase of the use of renewable energy.

Although the theory of green certificate systems is well elaborated, there is a lot of uncertainty about how they will function in practice. For investors, these uncertain factors lead to insecurity about the market value of renewable electricity. In addition, different lead times and transaction costs connected to technologies, policy systems, or country-based cultures create even more challenges for investors in renewable energy.

1.2 The ADMIRE REBUS project

Against this background, the ADMIRE REBUS project has been carried out[1]. The ADMIRE REBUS project addresses the interaction of different national policy frameworks in the current European renewable electricity market. Furthermore, the ADMIRE REBUS project aims at reducing investors' uncertainty by creating a framework for identifying risks and opportunities of renewable electricity investments in the EU, and for analysing renewable electricity policy designs. In order to stimulate investments in renewable electricity (RES-E) and to contribute to achieving the EU targets, the project provides information on the market value of green electricity, the investment opportunities and emerging markets. Political risks and uncertainties are explicitly taken into account.

For this purpose, the project has been structured into three different main activities.
1. Quantitative analysis of the EU market for green electricity using a dynamic market simulation: the ADMIRE REBUS model.
2. Qualitative analysis of those factors that introduce additional complexity to the investment decisions: risks, transaction costs, lead times.
3. Workshops with investors and other stakeholders, not only for dissemination of results but also to exchange experiences from the point of view of renewable electricity investors and project developers. In the spring of 2002, these workshops have been organised in London, Copenhagen, Paris, Madrid and Milan. A second round of workshops, disseminating the project results, has been held in May and June 2003 in Roskilde, Madrid, Paris, Mannheim and Brussels.

The results of these activities are described in the current report.

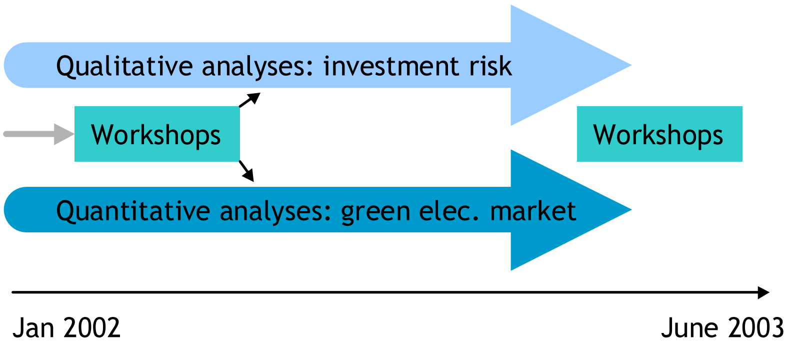


Figure 1.1 *Overview of main activities within the ADMIRE REBUS project*

1.3 Overview of the report

This report is one in a series of three.
- The current final analysis report focuses on current and expected developments in the EU market for renewable electricity.
- The methodology report (Daniels et al., 2003) gives a detailed account of the ADMIRE REBUS model, developed and used for the quantitative analysis. It also provides detailed information on the data collected within the framework of the project.
- The background report on challenges for investors (Skytte et al., 2003) provides more information on those issues most relevant to investors in renewable electricity, such as risks, lead times, and transaction costs.

The report starts with describing the approach and key assumptions used in the analysis. Next, Chapter 3 provides an overview of EU legislation and different support policies for renewable energy.

[1] The acronym stands for 'Assessment and Dissemination activity on Major Investment Opportunities for Renewable electricity in Europe using the REBUS tool'.

Chapter 4 gives a brief overview of the different challenges that an investor faces when investing in renewable energy technologies with respect to lead times, risks and transaction costs.

Chapter 5 looks at the future and discusses trends in policies and emerging markets. Next, Chapter 6 presents ADMIRE REBUS model analyses of different policy strategies for meeting the targets stated in the EU Renewables Directive. Chapter 7 continues the analysis of model results with presenting prospects for individual technologies and market prices under different scenarios. In this chapter also a brief evaluation is provided of other developments that could significantly influence developments on the EU market for renewable electricity. In Chapter 8, case studies are presented for four different EU Member States. Chapter 9 puts the results into perspective by describing the outcomes of sensitivity analyses. Finally, Chapter 10 draws conclusions and formulates recommendations based on the above.

2. APPROACH

This chapter gives an overview of the approach chosen for the quantitative analyses in the project. First, the ADMIRE REBUS model is described briefly - for a detailed account see (Daniels et al., 2003). Next, key assumptions on costs, potentials, and electricity demand and commodity prices are justified. Finally, a short elaboration is provided on the way the model calculates costs and expenditures related to renewable electricity deployment.

2.1 The ADMIRE REBUS model

The analyses described in this report are based on the ADMIRE REBUS model, a successor of the REBUS model[2] (Voogt et al., 2001). The REBUS and ElGreen models (Huber et al., 2001) simulated an 'ideal TGC market' in 2010 by using static marginal national supply cost curves that establish a correlation between the price of electricity and the amount of electricity produced from a given source per annum. The supply curves are based on estimates of different RES potentials based on costs and expected performance.

The ADMIRE REBUS model goes further than its predecessors, in providing a dynamical simulation of the development of the EU renewable electricity market, and giving insight in this developing market to the investors in renewable capacity[3]. The main issue to be taken into account is the variety of institutional settings present in the current EU renewable electricity market. When interacting on the emerging international market, this diversity may cause trade barriers and distortions. In the near future, the market may evolve to anything between the current situation and a fully harmonised European market with all or most distortions removed. Therefore, a model for the simulation of the developing market has to be capable of describing both the current situation and most conceivable future situations. In addition, it should be capable of simulating any intermediate situation that might emerge on the road towards a particular future situation. In order to describe such a transition, the results for any year should include the heritage of past years. Finally, such a model has to incorporate the influence on RES-E investor behaviour of the risks inevitably arising from any market in transition.

ADMIRE REBUS copes with this by applying a market-mechanism based dynamic algorithm, enhanced with a wide variety of mechanisms representing the effects of various kinds of barriers and distortions. The less the latter mechanisms are active, the more the market mechanism shines through in the results. Within the model, a more or less gradual inactivation of the barrier mechanisms is the equivalent of a trajectory from the current situation dominated by national policies towards a fully harmonised European market. In such a scenario, the influence of the 'market-core', initially largely covered by the barriers, becomes more apparent during the years. A vintage approach for RES-E capacity and registration of rights acquired from past policies ensure that the results for a particular year are the repercussion of a chain of events and do not merely reflect a momentarily market equilibrium. In this way the model incorporates the influence of both past and present policies and investor decisions.

The mechanisms representing various barriers and distortions reflect the discriminative characteristics of policies, and the ability of producers to choose whether they produce for the domestic market or wish to trade their production. Different levels and conditions of national support schemes will lead to the emergence of different sub markets with local equilibriums. ADMIRE REBUS can perform simulations for several target years up to 2030, taking account of various other factors complicating investment in RES-E, such as (political) risks, transaction costs and

---

2 REBUS stands for Renewable Electricity BUrden Sharing.

3 Roughly along the same lines, the Green-X model is being developed, see www.green-x.at.

delays due to planning and permitting processes. These factors contribute to a realistic simulation of the effectiveness of policy instruments.

The model gives a wide range of results, including equilibrium prices, RES-E realisations by technology, support policy and country, and costs subdivided in various categories. Figure 2.1 gives an overview of the main elements of the model.

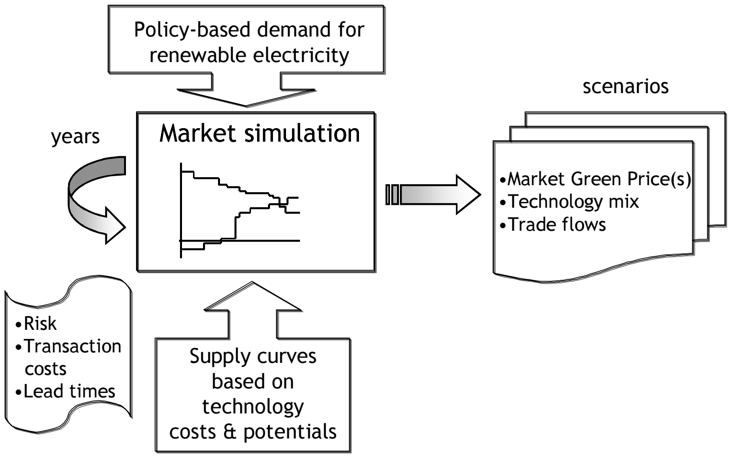


Figure 2.1 *The ADMIRE REBUS model*

Principle of the model

As mentioned, the core of ADMIRE REBUS is a market-mechanism based algorithm, supplemented with a wide variety of mechanisms representing all kinds of barriers and distortions. The main components of any market model are demand and supply. In ADMIRE REBUS, policies that stimulate production of RES-E represent the demand side of the renewable electricity market. The demand curve is dynamically constructed from a series of demand sections, based on an extensive inventory of policies that result in an incentive on renewable electricity production. The incentives are translated into a *bid price*, in ct/kWh, in combination with a demand size in GWh. This is the maximum incentive that an investor may receive as a result from this particular policy. These bid prices are the actual drivers of the renewable electricity market.

On the other hand, the actually available potential of the various RES-E options, or realisable potential, represents the supply side. Just as the demand curve, the supply curve is dynamically constructed from supply sections, consisting of an *ask price*, also in ct/kWh and a supply size in GWh based on technology and country-specific RES-E potential. The ask price, further referred to as *RGP (Required Green Price)*, is the net price an investor requires from the renewable electricity market in order to achieve a zero Net Present Value.

Demand and supply curves are illustrated in Figure 2.2. The model calculates a market equilibrium by generating matches between individual demand and supply sections, starting with the highest bid price and the lowest RGP, until there are no supply options left with an RGP lower than the bid price. Normally, such an algorithm would result in (piecewise) demand and supply curves, were it not for the aforementioned barriers and distortions. These enter the model as restrictions on both the allowed combinations of demand and supply sections and on the possibilities for producers to change from a demand section chosen in past years. The actual result is that each demand section has its own individual supply curve, constituted out of the eligible supply sections left over by preceding demand sections.

ADMIRE REBUS includes various mechanisms by which the past influences the current results. A vintage approach, administrating the abandonment of capacity constructed in past years, calculates the amount of existing capacity available for the market and the amount of abandoned capacity releasing its potential for new capacity. Existing capacity competes with a *Required*

Green Price based on marginal costs as compared to the total costs in case of new capacity. As a result, existing RGP generally takes precedence over new capacity. Further, the model translates the totally present *realistic potential* into the actually available realisable potential by evaluation of several institutional and techno-economical barriers in relation to model results of previous years. In addition, there is a registration of producers' rights acquired in the past due to the terms of particular support policies.

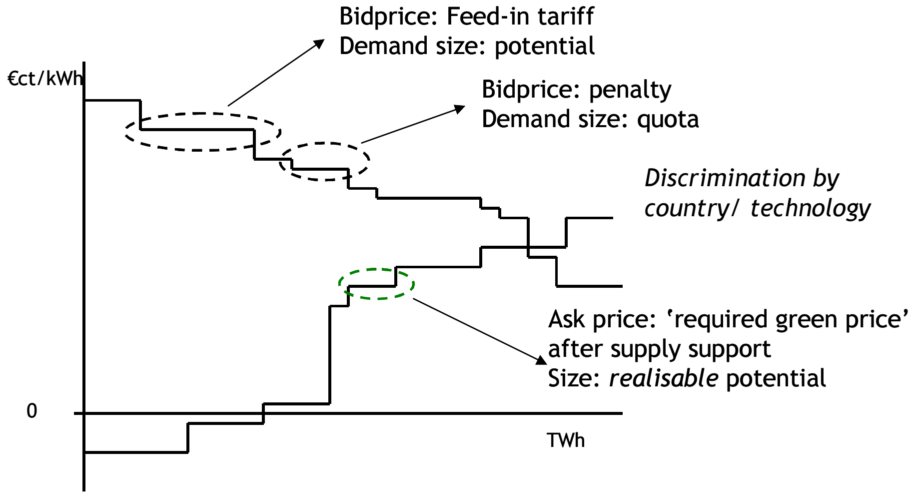


Figure 2.2 *Demand and supply in the ADMIRE REBUS model. RES-E production on horizontal axis, costs/price on vertical axis*

2.2 Key assumptions

This section briefly reviews the key assumptions used in the analyses presented in Chapters 6 and 7. A more detailed account of these assumptions in given in (Daniels et al., 2003).

2.2.1 Potentials and costs

Renewable electricity *potentials* determine the amount of production that can be realised based on specific technologies and in specific countries at a certain point in time. With the exception of the primarily site-specific technologies such as hydro, tidal and geothermal, the potentials have been constructed in a systematic way, relating each potential to its main constraining factor. For example, wind potentials have been constructed out of the available area with a particular average wind speed within a country. The factors that translate these areas into production include the maximum MW per area and load factors. Development in both the primarily constraining factor and the technology dependent translation factors lead to changes of the technical potentials in the course of years.

The *costs* of the various renewable electricity options are reflected in the *Required Green Price* (RGP). This Required Green Price consists of the average minimal green price that the investor has to or wants to obtain from the market over the lifetime of the production capacity in order to make the construction of additional green capacity (or the production with existing capacity) attractive. This means that the RGP incorporates the investment and production costs minus those and only those revenues, including those from support policies that the producer expects to obtain outside the green electricity market.

The RGP calculation also includes a required return on equity that takes into account the effect of uncertainties in various cost and benefit components. This calculation results in a risk adder on a risk free RGP, and subsequently converts this risk adder into an equivalent risk including required return on equity (RROE). A dedicated analysis results in the included transaction costs.

Various technological cost components originate from the general inventory of potentials and costs; the electricity prices reflect the current situation with an assumed gradual convergence on a European level. The latter may also be entered as scenario parameters. The table below shows the sources of the various RGP-components.

Table 2.1 *Inputs for the RGP calculation*

	Source
Investment costs	Costs and potentials inventory (see Noord et al., 2003)
Investment subsidies	Policy database (see § 3.3)
Variable production costs	
- O&M costs	Costs and potentials inventory (see Noord et al., 2003)
- Fuel costs	Costs and potentials inventory (see Noord et al., 2003)
Fixed production costs	
- O&M costs	Costs and potentials inventory (see Noord et al., 2003)
Reference electricity price	Current values, scenarios for future (see § 2.2.2)
Lifetime	
- Average economic life-time of technologies	Estimates (see Noord et al., 2003)
- Guaranteed support duration	Policy database (see § 3.3)
Required Return on Equity	Risk module (see Daniels et al., 2003)
Equity share	Estimate
Depreciation	Assuming linear depreciation
Interest payment	Calculated with debt share, investment, debt duration
Tax rate	Corporate tax rates EU member states
Investment transaction costs	Transaction costs analysis (see Daniels et al., 2003)
Production transaction costs	Transaction costs analysis (see Daniels et al., 2003)
Annuity	Constant with varying debt pay-off interest payment shares

Detailed information on *technology costs* is available in (de Noord et al., 2003). Below a short summary is given per technology. For some technologies a strong learning effect has been reckoned with, such as wind energy and certain biomass conversion technologies.

Table 2.2 *Overview of assumptions on technology costs*

	Assumption
Wind onshore	Reduction of investment costs of 35% from 900 €/kW to 590 €/kW (progress ratio 90%, strongest reduction in turbine costs, less reduction in tower costs and other costs, grid, civil works, infra etc.)
Wind offshore	Reduction of investment costs of 40% to 45% from 1900 - 2100 €/kW to 1140 €/kW (strongest reduction in turbine costs and costs for transport and installation)
Hydro	No cost reduction assumed. Band differences mainly caused by amount of civil works.
Solar PV	Reduction of investment costs of 80% from 5400 €/kW to 1100 €/kW. (technology development occurs mainly in module costs)
Biomass	Technology costs towards 2020: - Co-firing: no major cost development - Combustion: reduction of 10% - Waste combustion: increase in costs of 20% caused by stronger environmental requirements - Gasification: reduction of 50%, mainly caused by increase of unit size from 1 MW to 150 MW - Digestion: reduction of 10% - Fuel costs - Biomass: no major developments assumed
Waste	Fuel costs: increase of premium for waste removal, because EU policy requires incineration instead of landfill
Geothermal	No reduction of costs assumed

2.2.2 Electricity demand and commodity prices

Another important input for the analysis is the electricity demand projections, from which the indicative targets for 2010 are derived. These projections have been taken from (European Commission, 1999). The same projections have been used at the time when the Renewables Directive targets were negotiated and therefore provide a good reference.

Table 2.3 *Gross electricity consumption projections from (European Commission, 1999) [GWh]*

	2005	2010	2015	2020
Austria	65,888	70,626	75,926	79,626
Belgium	97,551	105,151	114,551	118,551
Denmark	41,700	44,400	46,100	47,400
Finland	89,914	96,614	104,614	111,314
France	510,947	537,701	611,163	652,526
Germany	577,177	613,277	657,139	690,539
Greece	61,400	72,463	81,663	92,063
Ireland	29,600	33,800	37,800	40,800
Italy	331,118	359,018	387,418	418,618
Luxembourg	6,951	7,951	7,951	8,051
Netherlands	117,828	132,688	144,688	157,488
Portugal	52,637	62,037	73,037	83,137
Spain	228,502	255,614	292,414	314,951
Sweden	162,100	162,563	172,663	173,326
United Kingdom	449,604	500,342	536,742	576,542
EU 15	2,822,918	3,054,244	3,343,869	3,564,932

Commodity prices for electricity are estimated based on wholesale/baseload prices and different for all EU Member States. These prices are increasing from on average 2.7 ct/kWh in 2000 to average 3 ct/kWh in 2010, assuming that overcapacity remains constant in the market and prices are dictated by the short run marginal costs of production. Table 2.4 presents the commodity prices. In addition, an intermittence penalty of 0.5 ct/kWh is imposed for wind capacity in Finland, France, the Netherlands, Sweden and the United Kingdom, in line with current balancing policies.

Table 2.4 *Commodity price developments for electricity [ct/kWh]*

	2000	2002	2005	2010	2020	Source
Austria	2.12	2.37	2.40	2.44	2.51	EXAA Energy Exchange Austria (spot, baseload)
Belgium	3.00	3.34	3.00	3.05	3.14	BPI (Belgium Price Index)
Denmark	2.24	2.70	2.48	2.52	2.59	Nordpool (baseload spot) Norpool (baseload forward 2005)
Finland	2.15	2.73	2.48	2.52	2.59	Nordpool (baseload spot) Norpool (baseload forward 2005)
France	2.00	2.20	2.40	2.40	2.40	Power next (spot baseload)
Germany	2.07	2.26	2.50	2.54	2.61	Estimate
Greece	3.30	3.50	3.50	3.50	3.50	Estimate
Ireland	3.00	3.07	3.15	3.15	3.15	CEER (Irish electricity regulator publications)
Italy	4.00	5.20	4.20	4.14	4.01	DRI-WEFA (European Power Prices: Explanations and Forecasts)
Luxembourg	2.07	2.50	2.80	2.80	2.80	Estimate
Netherlands	3.30	3.00	3.03	3.08	3.17	APX (spot, baseload) Nuon Market report (2005 OTC contracts)
Portugal	2.90	3.60	3.40	3.45	3.56	Estimate
Spain	3.00	3.90	3.50	3.55	3.66	OMEL (Spanish Market Operator, spot, baseload)
Sweden	2.15	2.76	2.48	2.52	2.59	Nordpool (baseload spot) Norpool (baseload forward 2005)
United Kingdom	3.30	2.50	2.77	2.81	2.90	Oxera scenarios, baseload central price

Note that there is a large uncertainty surrounding future developments of electricity prices. Factors that could significantly influence future commodity prices are the oligopolistic behaviour of market actors, investments in networks that increase trade and therefore price harmonisation among countries, the introduction of emission trade as of 2005, and the extent to which regions in Europe will function as completely open markets. See for instance (Scheepers et al., 2003) or (Boston Consulting, 2003) for a further elaboration of these factors.

Considering the ongoing vertical and horizontal concentration in the sector, and bearing in mind that overcapacity levels are decreasing, a second commodity price scenario has been constructed. Prices in this scenario reflect a tendency towards long run marginal costs and take into account of the influence of emission trade. All prices have been increased with 0.5 to 1 ct/kWh. Next, for the influence of emission trade, the assumption has been made that a permit price of 5 € per ton CO_2 leads to a 6.5% increase in power prices, see (Mannaerts and Mulder, 2003). Although this does not do justice to the country specific fuel mixes, allocation plans etc, the current level of uncertainty justifies the approach, meant for indicative purposes only. Table 2.5 presents the resulting prices for 2010, leading to an average of 4 ct/kWh, and gradually increasing between 2005 and 2010. Beyond 2010 these prices are kept constant.

Table 2.5 *High commodity price scenario [ct/kWh]*

Country	2000	2005	2010
Austria	2.12	2.40	3.62
Belgium	3.00	3.00	4.26
Denmark	2.24	2.48	3.71
Finland	2.15	2.48	3.71
France	2.00	2.40	3.00
Germany	2.07	2.50	3.73
Greece	3.30	3.50	4.26
Ireland	3.00	3.15	3.89
Italy	4.00	4.20	5.01
Luxembourg	2.07	2.80	3.73
Netherlands	3.30	3.03	4.29
Portugal	2.90	3.40	4.15
Spain	3.00	3.50	4.26
Sweden	2.15	2.48	3.71
United Kingdom	3.30	2.77	4.02

2.3 Brief review of cost calculations

As a preparation for the analysis in Chapters 6 and 7, this section gives a short review of how the model deals with cost calculations. Figure 2.3 presents an example of how the supply and demand curves of an individual country or a trading region could look like. The demand curve consists of three parts. On the left hand side, the curve represents the 'green market', i.e. the amount of renewable electricity produced that receives additional support. This part consists of two demand sections. First, a feed-in tariff that has been issued in the past, and to which a certain group of producers is still entitled[4]. Next to this, a quota obligation is shown for which all production except large hydro is eligible. The level of the bid price in this case is the penalty for not meeting the quota. Unless the market is short, an equilibrium price will be established below the penalty level. Third, the right-hand side of the graph represents the production that can compete on the grey market, but still counts for achieving the target, such as existing large hydro.

[4] Note that, although some of these producers have costs lower than the bid-price of the quota obligation, it is still more attractive for them to stick to the feed-in tariff.

On the left-hand side of the supply curve, there are a number of low or even negative costs options. These are installations built in previous years, for which we assume that they will produce as long as they can earn back their average variable costs[5]. Note that in the long run, they will need more revenues in order to cover their debts.

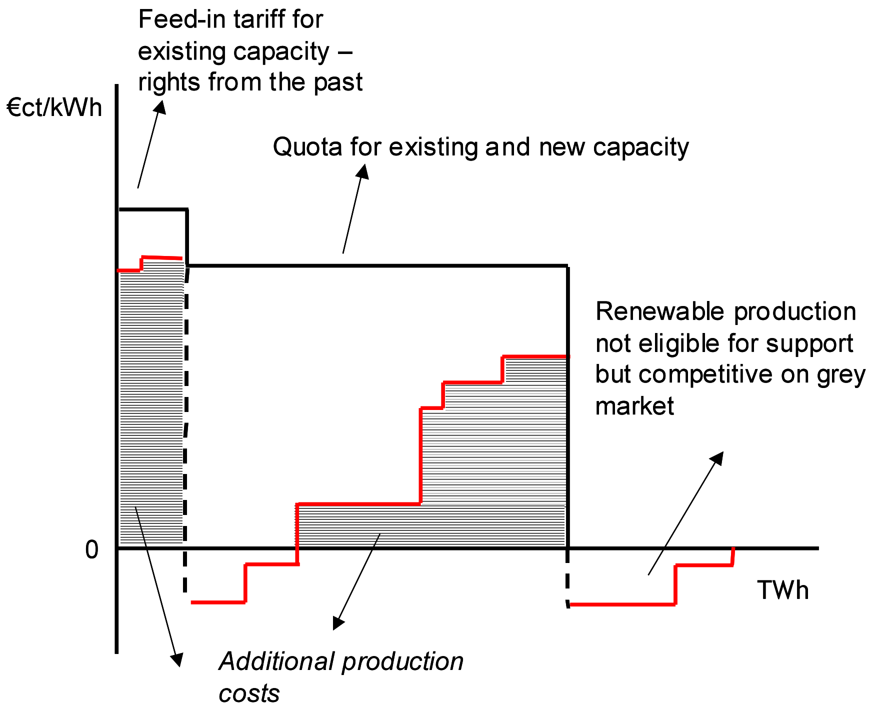


Figure 2.3 *Example of supply and demand curves in ADMIRE REBUS*

In this report, when comparing costs of different scenarios, we will focus on the additional costs of the options installed, in other words, the additional green prices required by producers multiplied by their production volumes[6]. These *additional production costs* correspond to the areas included in the supply curve and the x-axis, the shaded areas in the 'green market' part of Figure 2.3. This cost figure represents a lower bound to the actual costs incurred, because it does not include profit margins for either producers or traders. It could be taken to represent either a very efficient tender system, or the situation where the government would act as producer without any intermediate parties.

The model also calculates *total government and end-user expenditures*, representing the amount of money spent in order to stimulate renewables deployment. This is illustrated in he shaded areas in Figure 2.4. In this calculation the type of support scheme is taken into account. For a TGC scheme, the equilibrium price is taken to be the market price paid for all supply in the green market, while for a feed-in tariff, the cost calculation is based on the actual levels of the tariffs paid directly to the producers. These costs are more difficult to compare between countries and scenarios, because the parties spending and receiving money are not the same. The difference between *total expenditures* and *additional production costs* is the *producers' surplus*.

[5] See the ADMIRE REBUS methodology report (Daniels et al., 2003) for more details.

[6] Here the RGPs (required green prices) are used where the producer has not (yet) received any investment support. This way the value of the investment support given is also reflected in the cost figure.

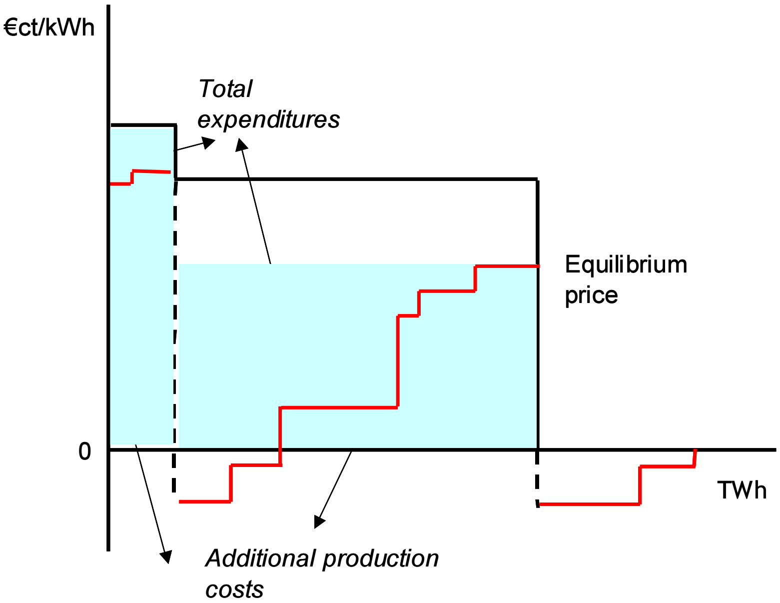


Figure 2.4 *Example of cost calculations in ADMIRE REBUS*

3. RENEWABLE ENERGY SUPPORT POLICIES

3.1 The EU Renewables Directive

The Directive on the Promotion of Electricity produced from Renewable Energy Sources (RES-E) in the internal electricity market[7], is the main legislation affecting RES-E at EU level. This directive aims at facilitating a medium-term significant increase in RES-E within the EU. It must be considered in the context of the indicative objective of doubling the share of renewable energy from 6% (in 1997) to 12% (in 2010) of the *gross inland energy consumption*. This objective was set in the 1997 White Paper on renewable energy sources[8] and endorsed by the Energy Council in May 1998. The White Paper includes an Action Plan and a Take-off Campaign that sets some specific objectives and key actions per technology.

This 12% of gross energy consumption has been translated into a specific share for *consumption of RES-E* of 22,1% in 2010 from 14% in 1997. The Directive also establishes indicative targets for the penetration of RES-E in each Member State (see table below).

Table 3.1 *Indicative RES-E targets in 2010 (including large hydro)*

	Total electricity consumption[9] [GWh]	Target RES-E [%]	Target RES-E [GWh]
Austria	70,626	78.1	55,189
Belgium	105,151	6.0	6,309
Denmark	44,400	29.0	12,876
Finland	96,614	31.5	30,240
France	537,701	21.0	112,917
Germany	613,277	12.5	76,660
Greece	72,463	20.1	14,565
Ireland	33,800	13.2	4,462
Italy	359,018	25.0	89,755
Luxembourg	7,951	5.7	453
Netherlands	132,688	9.0	11,942
Portugal	62,037	39.0	24,194
Spain	255,614	29.4	75,151
Sweden	162,563	60.0	97,538
United Kingdom	500,342	10.0	50,034
European Union	*3,054,244*	*21.7*[10]	*662,160*

7 Directive 2001/77/EC of September 27th 2001.
8 COM (97) 599.
9 Sources: Renewables Directive and European Union Energy Outlook to 2020.
10 The 22.1% of the Directive was based on a target setting in the first proposal of the Directive. In the adopted version, various countries had lower targets (e.g. NL has 9% instead of 12%), see also the many footnotes in the Directive. Therefore the realistic calculation achieves 21.7%. In practice the resulting percentage will depend on the realised electricity consumption in 2010.

Taking account of the wide diversity of the present promotion schemes between Member States, the Directive states that it is too early to set a Community-wide framework regarding support schemes. Accordingly, the Directive establishes a kind of minimum framework for renewable energy policy development in the Member States[11]. It does not announce a harmonisation of Member State support schemes, but only the intention to consider it *if necessary*. For that reason, it would be appropriate to regard this as a period of transition with a time schedule (see also Section 5.1).

3.2 Types of support schemes

Today, the EU electricity market is characterised by institutional innovation and diversity. However, in spite of fiercer competition, electricity markets, and in particular renewable electricity investments businesses are still shaped by national idiosyncrasies. So far this has been a necessity, since different Member States in the European Union have different mixes of renewable electricity support mechanisms in place or in preparation.

Some of them are designed to stimulate the supply of renewable electricity, while others affect the demand. This classification can be combined with another that distinguishes between generation based and capacity based support schemes (see figure below).

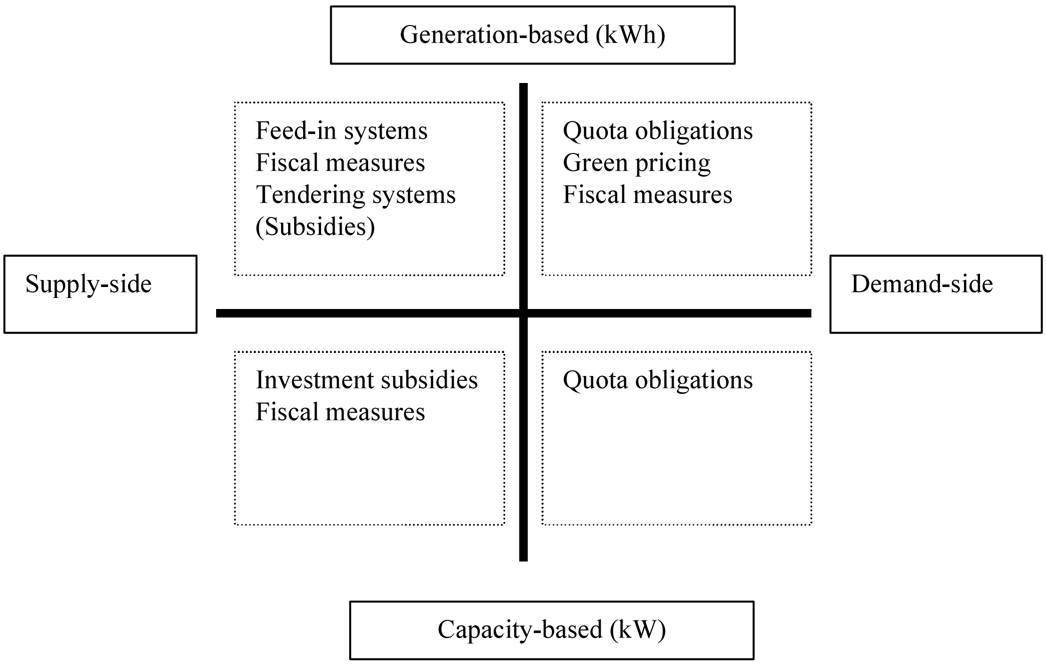


Figure 3.1 *Classifying RES-E Policy Support Mechanisms*

The main features of these policy instruments are as follows.

- Investment subsidies are the oldest, and still the most common type of schemes. This is one way to introduce non-competitive renewable energy technologies into a competitive electricity market. Investment subsidies are usually granted additionally to a feed-in tariffs system or a Tradable Green Certificates (TGC) system.
- Feed-in tariffs are widespread among EU countries. They consist of guaranteed premium prices, in combination with a purchase obligation by the utilities. They give a great deal of

[11] In the words of the Directive "(...) One important means to achieve the aim of this Directive is to guarantee the proper functioning of the (national) mechanisms, until a Community framework is put into operation, in order to maintain investor confidence" (number 14 of the Preamble). "It is too early to decide on a Community-wide framework regarding support schemes (...)" (number 15). "It is, however necessary to adapt, after a sufficient transitional period, support schemes to the developing internal electricity market (...)(number 16).

price certainty to investors since a premium on the electricity sold is assured for a specific, often long, amount of time.
- The TGC system is based on the separation of electricity as a physical commodity, and its 'greenness' emanating from the use of renewable sources. The 'greenness' is incorporated in a financial green certificate, which is issued at the moment of production, and which can be traded separately from the physical commodity.
- Fiscal and financial incentives are also widespread, but often put in place as secondary promotion measures. For instance, in some countries with quota obligations, with or without a TGC system, fiscal incentives are put in place to stimulate domestic demand.
- Tendering procedures is a way of creating competition for large investment projects, e.g. offshore wind farm. Once bids are awarded, they usually work as a feed-in scheme.

Some countries apply differing instruments for distinct technological options. Others propose two policy instruments for one technology, or several instruments depending on the size of the project. Theoretical features of the main policy instruments, together with opinions from the sector are described in (Skytte et al., 2003). The next section provides an overview of which support schemes are currently employed in the EU Member States. This also represents the contents of the policy database built in the context of the ADMIRE-REBUS project.

3.3 Country policy data

Before going into the details of each country, as presented in Table 3.2, it should be noted that, of course, not all promotion schemes have the same relevance for the promotion of RES-E. National promotion regimes are usually based on one of the following schemes (primary support measures): feed-in, TGCs, or, to a lesser extent, tendering/bidding systems. A second group of relevant but complementary support measures (secondary support measures) includes investment subsidies, fiscal and financial incentives. Countries usually have one (at most, two) of the schemes in the first group (except Finland). This is supplemented by a combination of measures pertaining to the second group.

Table 3.2 *Overview of RES-E support schemes in all EU Member States (Source: ADMIRE REBUS policy incentives database)*

Overview of RES-E support schemes in all EU Member States	
Austria	
Production support: • Feed in tariffs • TGC system for small hydro	Several policy measures conform Austria's renewable electricity policy promotion regime but in general it can be said that the core instrument has been the granting of feed-in tariffs. Those technologies benefiting from feed-in tariffs have been biomass, geothermal, solar PV and wind[12]. Support prices range from 6.37 ct/kWh for wind to 40.82 ct/kWh for solar PV. These prices are net of the price of electricity[13]. Small hydro (≤10 MW) is not covered by the feed-in system[14]. However, a different support scheme for this technology applies since 2001: a quota obligation based on a TGC system. A renewable minimum quota of 8% of the electricity sold to final customers has to be fulfilled by each distribution system operator until 2005. In the case of non-compliance, an equalisation levy will be imposed the Provinces. The Provinces are, independent from each other, responsible for the specific calculations. This levy is based on the difference between the average production costs of small-scale hydropower plants and the market price.

[12] According to the Law on the Organisation of the Electricity Industry (EIWOG 1998), which sets a new framework for renewable electricity, RES-E does not include hydro and waste.
[13] This means that the generator, in addition to the price of electricity, receives a support price in the form of a feed-in tariff. This also applies for the rest of countries that rely on fee-in tariffs to promote renewable electricity.
[14] In 2003 the TGC system for small hydro has been replaced by a feed-in tariff.

Overview of RES-E support schemes in all EU Member States	
Investment support	In addition to the above, other instruments have also been used to promote RES-E. Under the Umweltforderung im Inland program investment subsidies up to 30% of total investment are provided to biomass, solar thermal, geothermal, wind and solar PV. For small hydro the maximum support is 25% of total investment.
Other	Worth mentioning are also fiscal and financial incentives. Concerning the former a reduced rate of 10% VAT for biomass is applicable. Financial incentives are awarded to all RES-E technologies in the form of a % reduction in interest rates (between 4% and 50%).
Belgium	
Production support: • Feed in tariffs • TGC systems in Flanders and Wallonia	While the system of feed in tariffs will continue to exist, Flanders and Wallonia regional governments decided to introduce a (regional) green certificate system. Therefore, at least 3 systems will coexist in the future[15]. Concerning the National feed-in tariff, solar PV, wind, biomass and small hydro all benefit from a price support (net of electricity) of between 4.25 ct/kWh and 12.5 ct/kWh. The Flanders TGC scheme started in 2001. A penalty of 7.5 ct/kWh for not reaching the RES-E target has been set for producers/distributors. The penalty level increases to 12.5 ct/kWh in 2004. The Walloon region TGC system sets the obligation on the supplier (3% quota for 2003, which increases progressively until 2010 where the quota will be 12%). CHP is included in this obligation. The penalty has been set at 10 ct/kWh (except for the first time period, which is 7.5 ct/kWh).
Investment support	Investment subsidies are also provided by each region. For example, RES-E (wind, biomass, small hydro and solar PV) benefit in Flanders from an investment subsidy covering between 50% and 15% of total investment[16]. The Walloon region also gives investment subsidies (15% of total investment) to RES-E (biomass, small hydro and wind) At a National level, solar PV also benefits from investment subsidies (25% of total investment), which are granted by Electrabel.
Other	With respect to other fiscal incentives, investments under the Verhoogde investeringsaftrek regime are awarded a deduction from taxable profits of 13.5% of the investment, instead of the 0-3.5% deduction for normal investments.
Denmark	
Production support: • Feed in tariffs • TGC system announced	In Denmark the Electricity Act of May 1st 1996 set up feed-in tariffs for geothermal, small hydro (≤10 MW), biomass, tidal, solar PV and wind onshore in the range of 5.06 ct/kWh to 6.73 ct/kWh. This amount includes the net feed-in (i.e. it does not include the price of electricity) plus a production subsidy and a carbon tax refund. As of 2004 a TGC system is expected to be implemented[17] for the following technologies: wind, geothermal, biomass, small hydro and solar PV. The penalty to the consumer for failing to fulfil the purchase obligation will be 3.7 ct/kWh. The minimum price to be paid by the supply-obligation companies for a certifi-

[15] The regional government of the Brussels region has also manifested in favour of a TGC system, although the policy proposal is not as advanced at the time of writing as those of the other two regional governments.
[16] These percentages can be accumulated to the 25% investment subsidy provided by Electrabel (see below).
[17] It is not certain whether implementation will proceed. See also Section 8.1 for a comparison of the continuation of the current feed-in tariffs with the implementation of the TGC system.

	cate when issued is 1.4 ct/kWh. The existing biomass plants will continue to receive the electricity production subsidy (Law 377 of 2 June 1999). The new plants, which are constructed before the end of 2002 will obtain a fixed feed-in tariff for a ten-year period.
Investment support	As in other countries, there are other complementary instruments aiming at promoting RES-E. Investment subsidies are given to biomass, CHP, solar PV and wind. This subsidies vary between 15 and 30% of the construction costs for standardised RE-equipment and up to 50% for development projects. Investment subsidies for tidal electricity cover between 30% and 100% of total investment costs.
Other	Concerning financial and fiscal incentives, wind energy (onshore) may benefit from tax exemptions (deduction from taxable profits of between 60% and 100%).

Finland

Production support: • Tax refund and tax exemption	In Finland, electricity producers pay an annual electricity tax. The producers generally pass this charge on to their customers. These electricity taxes are returned back to renewable electricity producers. That is, producers of electricity from certain renewable energy sources (wind power, small scale hydropower, wood and wood based fuels) are given a tax refund at the end of the year of between 0.42 ct/kWh and 0.69 ct/kWh. On the other hand, RES are exempted from the carbon-based tax.
Investment support	In addition to these fiscal incentives, investment subsidies are also given to renewable electricity (small hydro, biomass, solar PV and wind). They cover between 30% and 40% of the total investment and are awarded on a case-by-case basis.
Other	Finally, there exist green pricing schemes for renewable electricity. Around 0.8 ct/kWh are given to existing hydro, wind, solar PV and biomass.

France

Production support: • Feed-in tariffs • Bidding system for wind onshore	Renewable electricity in France is promoted through a wide array of different promotion schemes. Many technologies receive feed-in tariffs based on the Electricity Law 2000. On the other hand, within the frame of the national wind power programme 'EOLE 2005', a specific bidding process was introduced in 1996. The programme is due to run until the year 2005. Stage 1 is to achieve 15 MW and stage 2.35 MW. Under this program, 5.5 ct/kWh are given to wind onshore.
Investment support	Under the FACE programme, investment subsidies of up to 70 % of total investment are given to biomass, wind and solar PV (stand alone systems). This programme is a scheme for Auto-producers of electricity from renewable energy sources in remote areas. The money comes from a fund financed by EDF, the national government, and the power consumers. Finally, a subsidy up to 30% of total investment in local wood-fired biomass plants is awarded under the 'Bois-énergie et le developpement local' program.
Other	Renewable electricity investments in overseas territories may benefit from fiscal incentives in the form of unlimited income tax exemptions. Other fiscal incentives are also given to all RES-E, such as flexible depreciation for investments in renewable energy production (100% of depreciation in only one year)

Overview of RES-E support schemes in all EU Member States	
Germany	
Production support: • Feed-in tariffs	In Germany, promotion of RES-E has been traditionally and fundamentally based on the feed-in tariff scheme (Renewable Energy Law[18]). Support prices are in the range of 7.03 ct/kWh and 4.03 ct/kWh (clearly out of this range is solar PV, which gets 48.55 ct/kWh).
Investment support	The 200-million DM programme and the Nutzung erneuerbare Energiequellen program provide investment subsidies for RES-E (biomass, solar PV, solar thermal, wind, CHP, small hydro). Total amounts (not percentages of total investment) are granted. The 250-MW-Wind Programme provides investment subsidies of up to 25% to a maximum of 46,016 €. Additionally, the programme provides operation subsidies of up to 3.1 ct/kWh fed into the public grid. Under the Nachwachsende Rohstoffe program, a subsidy of up to 50 % (60% in the East) of investment costs for demonstration projects in the agricultural non-food sector is granted. The BMU-Programm zur Förderung von Demonstrationsvorha provides loans up to 70% of the investment costs of RES-E demonstration projects at a currency of 30 years. For the first 10 years, the interest rate is 4.9% (1998), after that it will be dependent of capital market conditions.
Other	Other financial incentives are provided by the ERP-Umwelt und Energiespar-program, which provides loans with a reduced interest rate. Loans may mount to a 50% of investment costs. In the west loans up to 75% of the investment costs can be achieved at an interest rate of 4.5% for a maximum of 0.5 M €, with a currency of 10 years. For investments in the east the interest rate is 5.0%. The 100,000-roofs solar electricity programme offers a special zero-interest loan with a repayment period of 10 years and up to 2 starting years without credit repayment (for Solar PV). Green Pricing schemes are also available.
Greece	
Production support: • Tax refund and tax exemption	In Greece all RES-E benefit from feed-in tariffs whose level depends on category: Independent Power Producers (IPPs) and Auto producers (APs). Moreover, prices are different for Low Voltage (220/380 V); Medium Voltage (6.6,15,20,22 KV); High Voltage (150 KV) and for peak zone, medium zone and low zone. The Law 2773/99 sets an average rate between 5.6 ct/kWh and 7.2 ct/kWh, while the Law 2244/94 sets an average rate between 1.6 ct/kWh and 6 ct/kWh. In both cases Independent Power Producers receive up to 90% of retail price, while Autoproducers receive up to 70% and contracts are awarded for ten years
Investment support	The New Operational Programme for Energy (and Development Laws 1892/90 substituted by Law 2601/98) provided investment subsidies of between 38% and 57% for a wide array of renewables (small hydro, wind, solar thermal, solar PV, geothermal and biomass).
Other	Concerning fiscal incentives, the Law 2364/95 sets up to 75% deduction and tax exemptions for the purchase and installation of renewable systems and natural gas systems for individuals and up to 100% exemption for private companies.

[18] Section 8.3 addresses the amendments to the Renewable Energy Law proposed in 2003.

	Finally, from 1994 to 1999 biomass, wind onshore, small hydro and solar PV benefit from a capacity bonus, as envisaged in the Law 2244/94.

Ireland

Production support: • Bidding system	Since 1994, the development of electricity generating capacity from renewable energy has been encouraged through a series of Government supported Alternative Energy Requirement (AER) competitions. The objective of the AER is to increase the contribution of renewables in the overall electricity generating mix. The AER involves a series of tendering competitions, in which prospective generators are invited to compete, based on price per unit of electricity, for contracts to sell electricity to ESB. Successful competitors are offered ESB power purchase agreements of up to fifteen years[19]. There have been six AER competitions to date.
Other	In addition, the Irish government guarantees that all projects receiving funding under the EU THERMIE programme, have access to the electricity grid, via a THERMIE power purchase agreement based on AER prices. The current electricity liberalisation proposals (Electricity Regulation Bill, 1998, published December '98) now provide for green electricity producers to supply electricity directly to electricity customers via Third Party Access to the network from February 2000. All electricity customers will be entitled to purchase electricity, which is produced using a renewable or alternative form of energy as its primary source. The costs for using the public national grid (use of system charges) will have to be paid for by the supplier. There are regulations concerning transparency and quality for the calculation of grid-use prices.

Italy

Production support: • Feed-in tariffs • TGC system for new capacity	Promotion of RES-E in Italy is based on a feed-in tariff system although a TGC system has also been introduced. Concerning the feed-in tariff, utilities pay a price consisting of avoided fuel costs and a subsidy for the higher investments RES-E generators have to make. The subsidy for higher investments is only paid for 8 years and is dependent on the source of renewable energy. The extra expenses are funded by two levies electricity consumers have to pay: the Thermo-levy and the renewable plants levy. The feed-in tariff support goes from 5.3 ct/kWh (hydro <3 MW) to 12.5 ct/kWh (solar PV and biomass). Concerning the TGC system, those plants that have been constructed after April 1st 1999 may participate in the TGC system. A 2% obligation (for 2002) has been set on generators (>100 GWh/year) and importers to produce (or import) green electricity. Then on this base the related green electricity produced will be annually and for the first eight years labelled on request of owners[20]. The Decree of Ministry of Industry on 11 November 1999 concerning the electricity generation from RES establishes the 2% obligation and regulates the trading of green electricity. Green certificates have values corresponding to 100 MWh
Other	Apart from the feed-in and TGC systems, several fiscal incentives aiming at RES-E promotion are in place. On the one hand, there is a tax break of 1.03 ct/kWh concerning the heat supplied by the district heating systems fuelled by biomass to buildings located in very severe climatic conditions (geographic areas classified E and F). In addition solar thermal benefits from, both, a reduced VAT rate (reduction rate set at 10% for systems exploiting solar energy for the

[19] In addition, projects receiving funding under the EU RTD programme are also guaranteed power purchase agreements on similar terms to AER projects.

[20] This obligation can also be fulfilled by purchasing the necessary amount of green electricity (or related rights) from other producers or from the operator of the national transmission grid.

	heat supply to dwelling use) and a percentage deduction from taxable profits of 36% of the personal income tax for the investment costs concerning solar thermal projects in the building sector.
Luxembourg	
Production support: • Feed-in tariffs	RES -E promotion in Luxembourg is based on a combination of feed-in tariffs, fiscal incentives and investment subsidies. On the one hand, solar PV, wind and biomass benefit from feed-in support in the range of 3 ct/kWh (producers receive in addition a bonus of 11.2 ct/kWh for average peak load deliveries during the three principal annual peak load periods).
Investment support	Under a set of regulations (Skeleton Law 27.7.93, Grand-ducal Regulation 5.8.93, Ministerial reglementation 6.12.94 and PEEC Programme 11.8.1996) investment subsidies covering 25% of total investment costs are awarded to solar PV, wind, solar thermal, biomass, geothermal and CHP (in some instances the support can be raised by 5% in case the investment takes place in a defined geographical area).
Other	All renewables benefit from a flexible depreciation scheme. A 60% deduction from taxable profits is applicable. Under certain conditions, investments in RES-E technologies may obtain a 4.5% interest rate reduction.
The Netherlands	
Production support: • Demand stimulation • Feed-in tariffs	The implementation of TGC systems in the EU was pioneered by The Netherlands. From 1998 to 2000 a TGC system (the Green Label) was in place. Blocks of 10MWh were commercialised and the price per kWh was set by the interaction of supply and demand. In July 2001 a new system started. On the production side the scheme is based on a TGC system, but demand is created by a fiscal incentive instead of an obligation. Imports are eligible for green certificates since January 2002. The demand for TGCs is linked to the ecotax (REB) exemption. In 2002, there was a 60 €/MWh (6 ct/kWh) ecotax on energy consumption. Consumption of RES-E is exempted from this ecotax, which applies to the redeemed TGCs[21]. RES-E also benefited from a production incentive based on power contracts, worth 2 ct/kWh in 2002. In 2003, the REB system has been adapted. The policy scheme combines a lower exemption level of taxation on consumption with a technology specific feed-in tariff (MEP). The MEP will be paid to producers of electricity from renewable sources who feed in on the national grid, and is guaranteed for a maximum of 10 years. The level of producer support is differentiated for technologies. The highest support level (expected to be 6.8 ct/kWh) will be granted for wind offshore, PV, small stand-alone biomass installations, hydro, wave and tidal energy. The MEP feed-in tariffs are financed through a MEP levy of € 34 annually, on all connections to the electricity grid in the Netherlands. The MEP levy is essentially a type of system benefits charge that is collected by the distribution network operators and consequently passed on to the national transmission system operator. Green certificates will continue to be used in this mixed system.
Investment support	Investments in RES-E may be deduced from taxable profit. The rate from 1997 to 2001 varied from 40% to 52% of the total investment (with a maximum of approximately 22.5 M€). Nowadays, 55% of the investment can be written off (deducted from taxable profit) in the first fiscal year, with a maximum of 99 M€ per project (EIA - Energie Investerings Aftrek). Until 2002, an accelerated depreciation of investment (VAMIL) was also aimed at RES-E promotion (ex-

[21] The supplier purchases RES-E from the generator, which hands over TGCs (created in the generation) to the supplier. TGCs are finally surrendered to the tax authority which exempts the supplier from paying the ecotax.

	cept Waste). A 35% deduction applies to investments in RES-E and it is deducted from taxable profits.
Other	Concerning other financial incentives, investments in a recognised 'Green Project' can be financed with cheap loans from the so-called 'Green Funds'. The interest rate is on average 1% lower than the market rates.

Norway

Investment support	A combination of investment subsidies and fiscal incentives is used in Norway to promote RES-E. On the one hand, wind and biomass (heat production) may benefit from investment subsides up to 25% and 100% of total investment costs, respectively. Subsidies on demonstration projects for large wind may cover 100% of investment costs.
Other	In addition, wind (onshore) energy investments are exempted from both the investment tax and the energy production tax.

Portugal

Production support: • Feed-in tariffs	Feed-in tariffs have been set for wind, biomass, small hydro, geothermal and solar PV in the range of 2.7 ct/kWh to 34.7 ct/kWh (D.L. 168/99, which modifies D.L. 189/88).
Investment support	Several programmes and regulations envisage investment subsidies of between 30% and 60% of total investment costs to RES-E (MAPE-POE: Portaria nº 383/2002;198/2001;1219/2001, ENERGIA (Ministry of Economy) DN - 11-E/95 and SIURE (Incentives System for the Rational Use of Energy)). In some cases 50% of the subsidy is a refundable loan (3 to 4 years cadence). The other 50% is given as a non-refundable subsidy. Total investment costs must be larger than 50.000 € (at least for small hydro, wind and geothermal)(see the Admire-Rebus database for further details).
Other	RES-E also benefit from reduced interest rates and reduced VAT rates.

Spain

Production support: • Feed-in tariffs	The feed-in tariff has traditionally been the main instrument to promote RES-E in Spain. This situation will not change in the near future. Renewable electricity technologies are granted a fixed premium of between 2.17 ct/kWh and 3.01 ct/kWh. Significantly out of this range is Solar PV which obtains an average fixed premium of 27.1 ct/kWh generated.
Investment support	On the other hand, solar thermal may benefit from an investment subsidy covering a maximum 50% of total investment. Solar PV may get, as investment subsidy, between 263 and 553 cents €/W_P. In both cases, funds are made available on a year-by-year basis.
Other	Finally, and concerning financial incentives, the Línea IDAE-ICO provides reduced interest rates for small hydro, biomass, wind and solar PV and solar thermal. 3 to 5 percentage points' bonification (up to 70% of the project costs) may be financed. Maximum loans are 6.31 M€.

Overview of RES-E support schemes in all EU Member States	
Sweden	
Production support: • Feed-in tariffs • Quota/TGC system	The Feed-in system (with support prices in the range 0.97 ct/kWh to 1.95 ct/kWh) has up to now been the main instrument used to promote RES-E. However, this situation will change in the near future. As from May 1st 2003 a TGC scheme is to be implemented in order to reach the ambitious targets set by the government (to increase RES-E consumption by 10 TWh from 2002 to 2010). TGCs apply to wind, solar, geothermal, hydroelectric, wave and biofuel power. The obligation is put on the consumption side raising from 6.4% in 2003 to 15.3% in 2010. Generators are protected with minimum (guaranteed) prices of 6.5 € per 1 MWh certificate (i.e., 0.65 ct/kWh) for 2004. The minimum price will decrease over a transition period of 5 years. The table below summarises this:

	2003	2004	2005	2006	2007	2008	2009	2010
Purchase obligation [%]	6.4	7.6	9.5	11.4	12.8	13.9	14.6	15.3
Minimum price [ct/kWh]	0.65	0.54	0.43	0.33	0.22	0	0	0
Maximum penalty [ct/kWh]	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2

Penalty sanctions for not fulfilling the purchase obligation will be 150% of the volume weighted average of the certificate price during the 12 month period preceding the last day of submission for compliance with the quota undertaking. The penalty price is limited to 2.2 ct/kWh.

Since it is doubtful if wind power is going be deployed in large scale under the relative low level of TGC prices in Sweden, the Swedish government has proposed to give transitional subsidies for wind power production. This bonus is given until a windmill has run for 25,000 equivalent full load hours from it started to produce power. This transitional subsidy will only be given for a five-year transitional period 2003-2007, in which the bonus will be gradually phased out.

Wind subsidies [ct/kWh]	2003	2004	2005	2006	2007
	1.63	1.30	0.65	0.65	0.33

Investment support	In addition, investment subsidies of between 15% and 25% of total investment are granted to some RES-E (wind, small hydro and CHP)
United Kingdom	
	The UK's Renewable Energy policy objectives and targets are very much related to the Climate Change Programme targets of November 2000. This Programme was written to set out a strategy to achieve the UK's Kyoto targets for reducing the greenhouse gas emissions. One of the means to do so is the stimulation of production of electricity from renewable energy sources. There are four elements in the strategy in support of renewable energy:
Production support: • Quota/TGC system	The Renewables Obligation has replaced the Non Fossil Fuel Obligation (NFFO), a bidding system which has stimulated renewables deployment in the nineties. The proportion of renewable electricity required under the Obligations will increase between now and 2010. The obligation would account for around 3% in the first compliance period ending 31 March 2003, rising to about 10.4% in the year ending March 2011. To provide long term security for investors, the Obli-

	gation will then continue to apply at a minimum of 10.4% of sales until 2027. The renewable electricity produced within the UK will be rewarded with Renewable Obligations Certificates (ROCs). When a producer cannot reach the target, he can buy out the obligation at a price of 30 GBP/MWh (approximately 48 €/MWh). The money that is collected from companies that don't comply with their obligations and have to buy out will be distributed over the companies that have met their obligations. This redistribution will be done in proportion to the number of ROCs that have been presented.
Investment support	There are several investment subsidies, such as the New Opportunities Fund, giving 40% subsidy for biomass and wind offshore.
Other	Climate Change Levy (CCL) exemption for renewables

3.4 A survey of policy trends

In the framework of policy data collection, a survey of policy trends in all EU-15 countries has been undertaken. Questionnaires on expected renewable energy policy evolution were sent to renewable energy experts in each Member State (plus Norway), asking them to provide their insights on the expected RES-E policy trends in their respective country. The findings are presented in (Skytte et al., 2003) and summarised here.

In general, changes in support policies could be grouped into two categories. On the one hand, a so-called 'major change' might be expected in some Member States. This involves the substitution of a nationally predominant support scheme by a different one (this could involve, for example, the expectation that there would be a change from a feed-in system to a TGC scheme). However, we acknowledge that, in some cases, this might be an oversimplification, as the combination referred above is in fact an interrelation, which means that a change in one measure may involve a change in others).

Major changes

Major changes are already taking place in some EU Member States, such as Belgium-Walloon, where a TGC system has already been put in place since October 1st, 2002, in Italy where the TGC system has been introduced in 2002.

In some other Member States a major policy change is likely to take place, but there is still much uncertainty about that possibility. For instance in *Denmark*, the introduction of a TGC system has been postponed several times, and large uncertainty still exists on the planned introduction in 2004. In the *Netherlands*, the fiscal incentive has partially been replaced by a feed-in tariff scheme (see Sambeek and van Thuijl, 2003 for details), and further adaptations are imminent[22].

Finally, in *Ireland*, the government has announced the intention to release a consultation document in the first quarter of 2003 with the objective to set new targets for the year 2010 for renewable energy and CHP and to examine alternative measures for supporting these technologies.

No major changes expected

In other countries experts do not expect a major change in the policy support schemes in the short to medium terms. For example, this is the case in *Spain* where a depart from the feed-in

[22] In September 2003 the government announced the gradual abolition of the fiscal incentive in favour of a complete feed-in tariff system in 2004-2005.

tariff scheme is not perceived as likely to happen, in spite of certain statements from public policy officials questioning the level of support for wind.

Austria is a similar case. The feed-in tariff system remains the key policy instrument to promote RES-E and no major change is expected up to 2012. There are two reasons for this, according to the Austrian expert. On the one hand, the system is somehow changing now, in the sense that there is a harmonisation of promotion strategies from provincial level to national level. On the other hand, there has been a negative experience with the tradable green certificate system (for small-scale hydro). From 2012 onwards, a change in policy may take place in the form of joint climate policy and RES-E policy (trading system).

In *Germany*, there is a mix of uncertainty and continuation with the present system. In August 2003 the Federal Environment Ministry published a new proposal (amendment) for the new Renewable Energy Law. The proposal has been passed to the national ministries with the request for comments. The proposal still relies on the feed in tariff as the preferred instrument to reach the 2010 target. The proposal comes up with more differentiated tariffs, some lower and some higher as in the current law. See also Section 8.3.

Experts from other countries - *Greece*, *Finland*, *Portugal* and *Luxembourg* - do not expect a policy change (neither 'major' nor 'minor') in the future.

4. CHALLENGES TO INVESTORS

Restructuring of the electricity sector radically changes the basis for investment decisions. For potential investors in electricity generation capacity the restructuring will shift focus away from security of supply and cost minimisation, towards profit maximisation. In a liberalised market investors care not only about the expected return on their investments, but also about fluctuations in revenue.

When potential investors turn their attention towards profit maximisation, a broad analysis of the economic viability of one or more investment projects gains in importance. In this regard a comprehensive understanding of factors influencing costs and revenues associated with those projects is essential. Cost factors that are directly connected to the projects are normally well known or procurable (e.g. investment costs for machinery, buildings, ground acquisition or overhead and maintenance costs). Although those figures are subject to uncertainties or risks, investors are aware of their general impact on the profitability of an investment. In addition to these cost components, investment projects are exposed to a further source of potential costs. Especially investors in RES-E encounter various administrative steps to be taken previous to the actual construction of a plant.

This implies that an investor has to face several kinds of challenges when he is evaluating the opportunity to undertake a specific investment and the modalities of development of his project. He has to evaluate the time that will be needed before the first money comes in, the costs and risks he will incur. In the case of emerging markets such as the market of renewable energies, these challenges are especially acute, as the amount of available experience on which one can rely is not high.

In general the challenges lies within three elements of the investment;
- The *lead time* before the production can start - this determines *when* the revenues from the investment will start.
- The *transaction costs* incurred before the production can start.
- The *risk* described by fluctuations in revenue when the production is running.

These elements will be further analysed in this chapter.

4.1 Lead time and transaction costs

Investors in RES-E encounter various administrative steps to be taken previous to the actual construction of a plant. Explicitly or implicitly most of these steps lead to time and costs that can be referred to as *lead time* and *transaction costs*.

In general, transaction costs are the costs that arise from initiating and completing transactions, such as finding partners, negotiating, consulting with lawyers and other experts, monitoring agreements, etc., or opportunity costs, like lost time and resources. The most obvious impact of transaction costs is that they raise the costs for the participants of the transaction, i.e. the investors, and thereby lower the expected profits or even discourage some transactions from occurring. In this case they prevent investments from being undertaken. The aim of this section on transaction costs is to give an overview of potential cost drivers and to create awareness of their importance. Investors may want to use the given framework to structure several sources of transaction costs and include them in their economic analysis of an investment project.

The complete process of an investment in a renewable electricity generating plant can be considered as one sequence of transactions. Therefore, transaction costs are those costs that go beyond the pure investment costs and arise from various sources. Lead time and transaction costs arise in different phases of an investment project. An investment project can be divided into three main phases:

1. the planning phase,
2. the implementation, construction and commissioning phase,
3. the production phase.

These phases are illustrated in Figure 4.1 below.

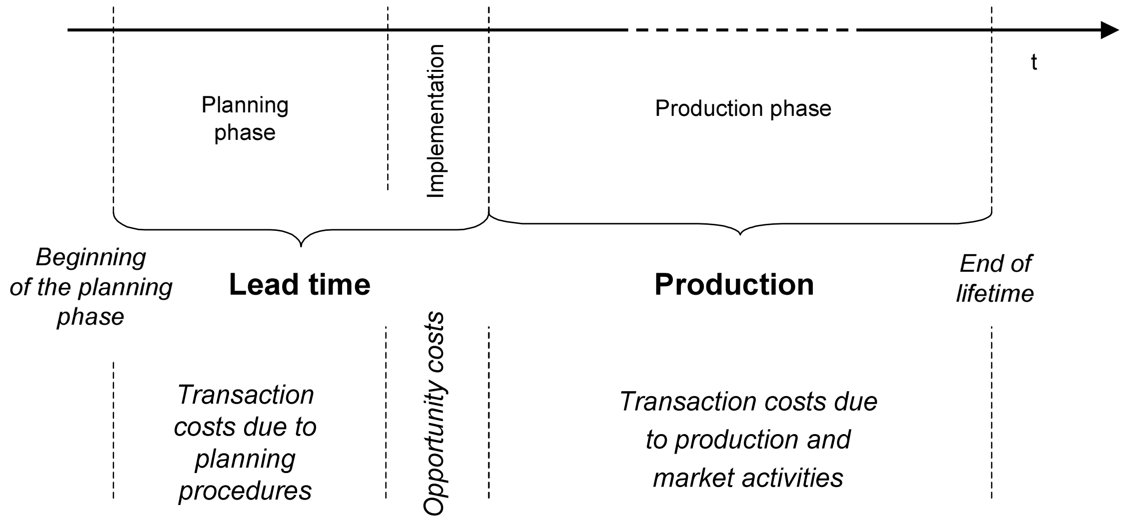


Figure 4.1 *Different phases of an investment project and associated transaction costs*

Revenue is generated only in the production phase. The first two phases do not generate revenue; on the contrary they bring about many costs and uncertainties. These costs and uncertainties have to be taken into account in the evaluation of the investment by the investor. More or less time can pass between the investor's first moves about a project and the start of the production phase. The investors have many different steps to undertake between the moment they become interested in a site and the moment their production unit is finally working and bringing in the first flow of money.

In order to evaluate their investment correctly, they need to be able to estimate the time and costs of the first two phases. This can be done quite easily for the implementation, construction and commissioning phase - and we will elaborate on this issue below. The time required for construction depends on factors that do not vary a lot: the availability of material, and of technical staff. There is little uncertainty. However, evaluating the costs and length of the planning phase is much more difficult.

4.1.1 Implementation phase

Transaction costs in the implementation phase are opportunity costs and are determined by the *Construction and commissioning time* i.e. the time from obtaining the building permit to selling the electricity.

4.1.2 Production phase

The production phase can be divided into sub-phases. These are:

- *Monitoring*: Efforts the participants must make to observe the transaction as it occurs, and to verify adherence to the terms of the transaction.
- *Enforcement*: Time and expenses to insist on compliance once discrepancies are discovered.
- *Adjustment*: Time and costs of changing strategies, due to a change in regulations or new scientific discoveries.

Transaction costs can either be real expenditures or work load. Note that the first two phases are strongly connected to the lead time of an investment project. More precisely, those phases of the lead time in which an investor is 'active'[23] can be used to transform the time into transaction costs. Any phase in which an investor is 'passive'[24] can be considered as opportunity costs. Any type of transaction costs arising from these two phases raises the total costs of the investment project.

4.1.3 Planning phase

In the planning phase, the costs are the costs of man-days that are required to carry out the project and will be taken into consideration as transaction costs. The corresponding *length* of the planning phase is the lead time of the phase. The following presentation is a global pattern of the planning phase that can count more or less steps in some cases and in which the order of some steps can change, but it roughly represents what investors have to go through for most of the technologies and countries.

The *planning phase* can be divided into three sub-phases (see Figure 4.2).

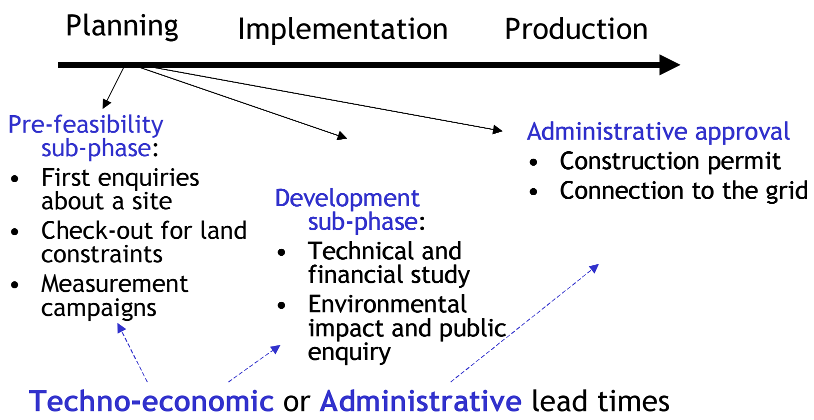


Figure 4.2 *Sub-phases of the planning phase*

The sub-phases can be characterised as

- *Search/pre-feasibility sub-phase*: Finding interested partners to the transaction as well as identifying one's own position and optimal strategy. Examples may be
  - search for a suitable site,
  - choice of the desired technology,
  - rough determination of the available budget,
  - first enquiries about a site,
  - check-out for land constraints,
  - measurement campaigns,
  - accomplishment of one or more pre-feasibility studies.

[23] I.e. where an investor explicitly employs workforce for negotiating, searching, monitoring etc.
[24] I.e. an investor is waiting for a proposal being approved etc.

- *Negotiation / development sub-phase*: Coming to an agreement. Technical and financial study. For example,
  - negotiating the terms of a contract takes time,
  - visits to the project site,
  - hiring lawyers to draft contracts,
  - evaluation of different financing schemes for the project,
  - negotiations regarding loans,
  - economic and technical feasibility studies,
  - environmental impact and public enquiry
  - This sub-phase usually ends with concrete investment projects, i.e. the aim to invest in specific technologies at specific sites.
- *Approval / administrative procedures*: The planned investment must be approved by a government agency. Modifications could be imposed on the deal.
  - Construction permit.
  - Connection to the grid.

The time-lag that is needed to carry out a project from the first moves till the moment the electricity sales starts is referred to as 'lead times'. The problem for investors is that lead times can vary a lot from one country to the other, but also within a country from one region to the other and even often from one project to the other.

Two kinds of lead times can be discerned:
- Techno-economic lead times.
- Administrative lead times.

Techno-economic lead times are linked to the pre-feasibility sub-phase, and to the development sub-phase. The pre-feasibility phase is a prerequisite to the setting up of the project's technical and financial documents and to the investment decision. First, the investor has to locate a site that is of interest. The time needed for this mainly depends on his own time schedule. This time is quite diluted as the task to look for a site is often mixed while carrying out other activities. There is then a first eye check of the place, where the investor can judge if there are no obvious impediments on the site (e.g. the presence of some monuments for wind projects or the physical disposition of a river). The check out of land constraints depends on the investor only: he has to verify that the land is free of constraints and available for his project. This verification consists of consulting some administrative files (that might already be available for other building projects) and does not require permission from the authorities. A measurement of the resources has to be carried out. For a given technology, this usually takes the same time in all Member States. It can of course be very different from one technology to the other. This sub-phase is a purely technical one; its length is usually easy to evaluate and does not vary a lot. All of these tasks depend on the investor himself and are therefore quite easy to speculate upon. The same goes for the technical and financial study. This is a part that the investors often know well and are used to carry out.

Things are different when one comes to the administrative lead times. The investor has to obtain the authorisation to go ahead with his project in three different sectors of the Law:
- Energy Law: permit to exploit, connection to the grid, sometimes a contract with the national electricity company (in case of a feed-in tariff).
- Land Law: building permit.
- Environmental Law: rivers, landscapes, emissions, forests, etc.

Usually, these regulations are supervised by different administrations, which multiplies the number of interlocutors, forms and attachments. The investor has to wait for decisions from these administrations. And the greatest problem they encounter is that often these administrations have, for various reasons, longer delays than those that are planned in theory. The reasons for that can often be detailed when reviewing the different technologies, but one constant is that the permits are given by local authorities which are very much linked to local life and sensitive to local influences and pressure groups.

Moreover, although the European Commission has set targets to achieve in terms of developing renewable energies, for the moment, Member States are free to promote renewable energies according to a national policy. Hence, administrative procedures and attitudes of the administrations vary a lot among Member States. In case of investments abroad, the investor has to learn how to deal with other policy and administrative regimes and other lead times.

4.1.4 Case: Lead times in the planning and construction phases for wind power

The different steps of the planning phase for wind power onshore

During the pre-feasibility study, the investor has to make a site check visit. He screens on the spot to see if there are no major barriers to the use of the given site. For example, he will look for the presence of remarkable sites next to the chosen field and will evaluate the distance to the closest houses. The first enquiries also need to assess the distance to the grid, the presence of strong local associations (have they already opposed some building project?) and the presence of obstacles to the propagation of the wind. If the site appears to be a potentially sensitive issue, then it is very likely to be dropped at this stage. If the site passes this first screening, then it should be checked if it is free of constraints. Here the investor has to check if there are no civil, military, environmental constraints that apply to the site. For example, if the site is situated in a bird migration corridor or on an area reserved for the preservation of nature, it should be avoided. The investor also has to make the first contacts with the owner of the land to obtain his agreement. The pre-feasibility sub-phase for wind power ends up with a campaign of measurement of the wind onsite, which generally lasts around a year. It requires the instalment of measurement masts.

A project in wind energy has to satisfy the three regulations mentioned earlier (Land laws, Energy laws, Environmental laws). In all Member States, the investor has to get a building permit, which has to be granted according to the country spatial planning regulation. Among the documents and requirements needed, the measurement of the project environmental impact is a crucial one. This environmental impact assessment (EIA) comes from the European Directive 85/337/CEE of 27 June 1985 and deals with the assessment of the environmental impact of some public and private projects. The categorisation of RES projects concerned by this EIA is left to the appreciation of Member States. It has to analyse what effects the project will have on the physical and natural environment as well as its socio-economic consequences. Applied to wind power, it includes generally estimation of noise, of shadow effects of wind turbines, of visual impact. The amount of work needed by this evaluation varies according to the countries and the size of the project. It can take the form of a short study or in-depth study made by an expert consultancy.

The application for a building permit can also lead to a public enquiry. This is not mandatory in all countries, e.g., in France it is now for projects over 10 or 25 hectares depending on the areas. In Italy it is not but will be in the next year or so. In all countries where there is an EIA, the project has to be made public and people can react. In Germany, the authorities have the obligation to inform the public and associations. Neighbours can be consulted after the application by the developer. In Denmark there is a public hearing during the instruction of the permit. An investor has also to ask for his connection to the grid. Finally, it is necessary to obtain an authorisation to exploit the production device.

The length of the planning phase in wind power onshore

According to the qualitative survey (Skytte et al. 2003), the distribution of the average planning phase for wind power projects onshore is given in Table 4.1. Average lead times for the planning phase in Europe are situated between 1.5 years and 4.5 years. Southern countries tend to have longer lead times than others. If we have a look at the extreme lead times that were experienced, we get the following picture:

Table 4.1 *Lead times for the planning phase in wind power (in years)*

Wind power	Min	Max	Average	Ratio Max/Average
Austria	0.6	5.0	2.0	2.5
Belgium	1.0	10.0	2,5	4.0
Denmark	1.0	5.0	2.5	2.0
France	3.0	6.0	3.5	1.7
Germany	0.5	4.0	2.0	2.0
Greece	2.5	7.0	4.5	1.6
Ireland	1.0	4.0	1.5	2.7
Italy	2.0	6.0	3.5	1.7
Luxembourg	1.5	4.5	2.5	1.8
Netherlands	0,5	3.5	2,5	1,4
Spain	1.0	8.0	3.0	2.7
UK	0.5	5.5	2.0	2.8

Some countries (Belgium, United Kingdom, Spain, Ireland, Austria, Denmark and Germany) show maximum lead times that can last twice the average planning phase or more. In fact the countries where lead times are shorter show a higher variation of lead times because they cannot help some slow cases. Proportionally countries where the planning process is slower are more stable regarding the variations encountered.

In almost all countries, the maximum lead time is on the order of twice the average lead time needed. This leads to uncertainty about the actual length of the lead time. There are some countries where the maximum lead time lasts more than 5 years (Belgium, Spain, France, UK, Italy). However, if one compares the ranking of the European countries in terms of dynamism[25] with the level of uncertainty that is shown here, one can notice that a high level of uncertainty in administrative procedures does not prevent investors from undertaking new projects in wind power. Indeed, Member States which have a high feed-in tariff for wind power can have a dynamic wind power deployment even with large maximum lead times, e.g. Italy and Spain.

In addition, there can be differences between lead times experienced in the different regions of the same country. That is the case in the UK: in Wales, the planning phase go up to 3 years, while in Scotland it is 1.5 years. England lies somewhere between the two. This is also the case in Spain, as authorisations for construction are given by regional governments and no single uniform criteria exist across them (therefore, 17 different approval procedures).

Investors are not sure to obtain the authorisation even if they follow all the procedures. In the survey, investors have been asked how many projects they would present to approved proposal (The success rate). One can evaluate the number of projects that have to be presented to get one permit in the wind power sector as the following. The arrow table below indicates these numbers for different Member States.

[25] Cf growth rates in the EurObserv'ER barometer annex.

Figure 4.3 *The success rate in wind power*

1	2	2-3	4	5	10	[year]
Ir	Lux	It	DK	D	ES	
				UK		
				B		
				F		

The figure illustrates how difficult it is to get a permit. But it should be noted that, in Spain for wind power, expected administrative delays and risk of not being authorised, often lead investors to increase the number of projects to be presented in order to get one permit, even if some of these projects are not fully economically feasible. It is a sort of negative feedback process: expected delays and non-approval leads to submission of many projects, some of which are not feasible, which increases the non-approval rate, which, in turn creates the feeling that approval is difficult. This may explain the low success rate in those countries.

Hence, the failure rate number is not to be taken for granted (especially in the investor's calculations of the required revenue for green value of electricity). Also it comes from a small number of interviews. And investors can have different ways of approaching this stage: on the contrary some try to present few requests but really carefully study them and validate them with local actors so that lower the risk.

In fact, the taking into account of lead times should be sufficient from a survey perspective. Indeed, the more numerous the problems, the longer the lead times. And the problems creating lead times are also the sources of failure for the project: opposition from local associations, difficulty for the authority to issue a decision, competing uses, etc.

Problems that can cause delays

There are several causes of delays in the course of a wind power investment project. The two main reasons for extended and uncertain lead times lie with administrative procedures and local opposition.

One of the principal administrative causes of delay is linked to *spatial planning*. The necessity to be coherent with the country spatial planning often brings about the necessity to revise local plans (which explain the possible use of land in municipalities). Indeed, in several countries, the local plan does not include wind turbines. Hence they have to be reviewed at a local level when a project appears. This procedure is usually quite long.

Construction phase

Compared with the above discussion of the planning phase, the transaction costs and lead time in the construction phase are more homogeneous between the different Member States and technologies. Regarding onshore wind power construction delays are the following:

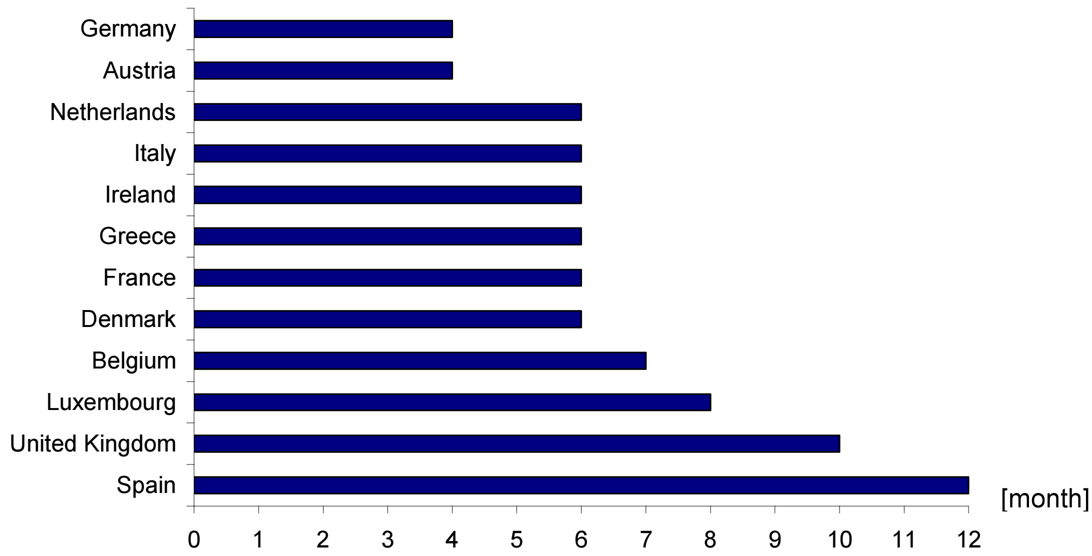


Figure 4.4 *Overall average construction time for wind power (in months)*

In all Member States, it takes less than a year, and for two thirds of them it takes less than a half year. From this survey we can infer that construction time does not represent a specific problem regarding lead time. It is usually well known and estimated by investors. However, construction time varies according to size of the projects.

Offshore wind power projects
Regarding administrative procedures, there are additional requirements for offshore wind farms which are linked with maritime laws (offshore concessions in order to avert dangers to the safety and smoothness of the traffic and to the maritime environment) and authorisation of farm-to-shore cable for connection to the grid. All countries require an Environment Impact Assessment. Construction time is longer because offshore wind farms require specific and complex foundations. On the whole, offshore projects can be estimated to last two years more than on-shore projects.

For offshore wind projects, delays are caused by problems of the same nature as for wind on-shore, such as conflicts with local actors on environmental impact (bird migration), visual impact, and impact on fishing industry. Several countries (UK, France) plan on making call for tenders for offshore projects in order to fulfil European objectives in terms of installed wind power capacities. This can mean fewer difficulties to obtain permits and authorisations in the future.

4.2 How to reduce lead time?

There are several directions to take for reducing lead times. They are valid whatever technology is concerned. Some of them depend upon investors' work, others from administrative regulations.

When examining causes of delay, we have highlighted the recurrence of conflicts with local actors. Of course, R&D can reduce technical nuisances. But technical and rational aspects are not all. Conflicts are often generated because of a lack of understanding of the project and its impacts. It is up to the investors themselves, and many already do, to seek consensus with local actors. More weight is given to the public in the decision process, mainly upon the influence of European legislation.

Local authorities, which have the power to grant construction permits, are also very important to consider at an early stage of the planning phase. Investors should consult local actors by doing more fieldwork: meetings of information, early consultation with the planners. The public has to feel his demands are taken into account. Market research should be done in order to know how to explain a project, what are the informational and emotional needs of the public who will be presented the project. Investors have to tackle the issue of what the impacts of a project will be in order to prevent the forming of collective anxiety around their project.

The other main source of delay is administrative procedures. Investors can prevent part of the delay by legislative monitoring and political lobbying. But the main action here is for competent authorities to simplify and clarify procedures, there are general principles that have been stated during workshops and interviews with experts and that have been also developed in studies:

- Identification of favourable sites both from the resource potential (e.g. Luxemburg's wind power Atlas) and from the local planning perspectives.
- Revise local planning when a clear strategy for the development of renewable energy sources is missing. Elaborate a guide to local authorities about how to plan RES deployment.
- Idea of a one open window: one interlocutor for all permits and document deliveries.
- Explicit guidelines on what is needed and established standardised indicators: which documents, presentation, themes, specifications, etc. This is valid for EIA.
- Pre-examination of a project in order to scan projects that have no chance of being granted authorisations.
- Imposing a mandatory time frame to authorities
- Create lighter procedures for small projects.

4.3 Risk described by fluctuations in revenue

Other challenges to investors lie in identifying risk described by fluctuations in revenue when the production is running. Fluctuations in revenue make an investment risky since the investor does not know exactly what his revenue from a given investment will be. Therefore, an investor[26] will require a risk premium in order to invest in a risky investment project compared to investing in a less risky project. In other words, the risk premium represents compensation to the revenue of the investment.

4.3.1 Creating a framework for analysing risk factors in different policy designs

If there were only a few causes to the fluctuations in the revenue the investor would easily be able to estimate the consequences of different causes and thereby the risk premium. However, the causes to the fluctuations are numerous. For a potential investor the large amount of causes and effects of risk connected to an investment can seem boundless. Therefore, the challenge lies in simplification and in creating a suitable framework for analysis of policy designs and modelling of investor's risk premiums.

The framework should make it easy for investors to identify major risk sources, classify their importance and create satisfactory estimates of the parameters needed to evaluate the investment opportunity.

In the following we describe a way of dividing basic risk factors into different categories. As a success criteria for this type of division we look at four basic functions that such a framework should serve:

- Enable decision-makers to quickly identify separate risk factors, their importance and their interdependence.

[26] If he is risk adverse.

- Enable a division or generalisation of different types of risk factors across categories such as type of technology or geographical region etc.
- Analyse the effect that policy instruments will have on investor uncertainty and thus the required risk premium.
- Facilitate the modelling of investment risk in a model such as Admire-REBUS.

When setting up a framework it is important that these basic functions govern the structure that is chosen, i.e. the structure of the framework should be suitable for the subsequent analyses.
If the risk considerations are done in order to collect data or estimating where the risk origin from one should characterise the risk according to the sources of risk.

One distinguish between *political, technological* and *market based causes*[27] as illustrated in Figure 4.5. This approach makes it easy to extract information from data e.g. technological data, market data or political trends. In this framework market risks and technology risks are largely related to inherent risks in the existing system and it will often be possible to model the individual components using statistical distributions.

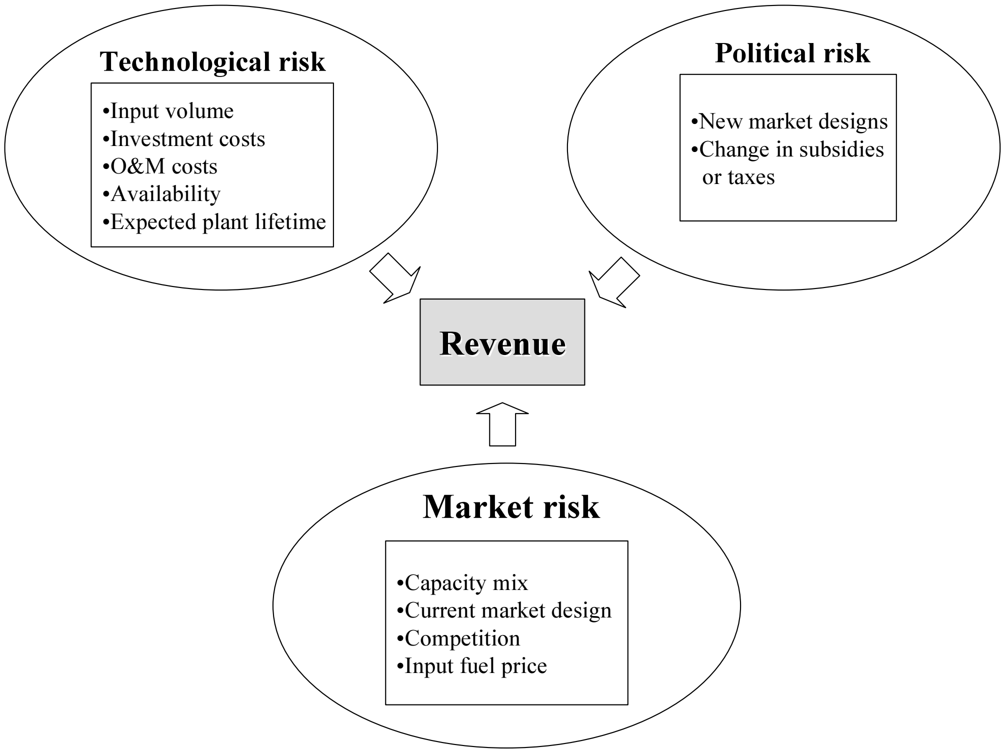


Figure 4.5 *Risk factors divided into Technology risk, Political risk and Market risk.*

Market risk holds all risks related to the currently chosen market structure and technology risk covers all technical risks related to the costs and availability of the plant. Political risk is related to possible changes in the system based on political decisions[28] e.g. the switch from a feed-in tariff to a TGC system.

[27] The separation of these risks has been undertaken for analysis purposes, but (as in any system) the three sets of risks are interrelated and multiple inter-linkages and feedback processes among them exist.

[28] This type of risk is generally more suited for a qualitative form of analysis where each political decision is analysed as a scenario. Political risk is thus seen as a binary variable: either a new market design (e.g. support scheme) is chosen or it is not.

4.3.2 Market risk

Market risk is a standard term from financial markets and in the electricity sector this type of risk will generally refer to fluctuations in the prices of electricity and/or fuel being used by the plant. In general, market risk holds all risks related to the currently chosen market structure.

Competition and technology risk
This type of risk covers both the risk of new technology developments that can outdate the technology of an already chosen investment and the risk of fierce competition in the chosen region.

Currency risk and exchange rate
Again a classic form of risk from the financial markets. With the introduction of the Euro this type of risk becomes insignificant when looking at Europe as a closed system. Currently the risk is however very real in Northern Europe where German, Danish, Swedish and Finish producers acting at Nord Pool must trade in Norwegian kroner (NOK).

Interest rate risk
Interest rate risk represents the stochastic movements over time in the interest rate and is relevant for all investments. It is generally not modelled explicitly in the most basic form of investment calculations, the Net Present Value theory, where a constant risk adjusted rate is used to discount cash flows.

Electricity price
The price for physical delivery of power at the electricity markets is called the electricity market price. If the level of financial support to a technology depends on the level of the electricity price, fluctuations in the electricity price influence the risk described by fluctuations in revenue. This is especially the case in systems where the physical power is sold directly at the power market and additional support only forms a smaller part of the total sales price for RES-E, e.g. this in a TGC system.

In a liberalised power market the electricity price is determined at markets that are characterised by short-term energy sales and price volatility. Electricity prices may fluctuate from hour to hour and between seasons. The spread of the fluctuations depends on the technology mix at the market and the load profiles. On one hand, in the Nordic countries, which are dominated by electric heating at the demand side and hydropower at the supply side, large fluctuations have been observed. On the other hand, only small fluctuations have been observed in thermal based systems (Olsen and Skytte 2003).

In a market-based support system, e.g. the TGC system, the RES-E producers get part of their revenue directly or indirectly from selling electricity at the grey electricity markets, e.g. the spot market. An electricity producer can sell electricity bilaterally on the over-the-counter market (OTC) and/or at an organised power exchange (power pool). The bulk of transactions are still being settled on the OTC market, but in recent years several EU countries have established power exchanges with spot markets (Olsen and Skytte, 2003), where the electricity price is settled on a daily basis.

In support systems with fixed RES-E prices (e.g. feed-in tariffs) the volatility of the electricity market price is of no importance for the investment risk. The risk (if any) is political risk and thereby not a risk connected to the price as a market risk.

TGC price
In a market-based support system, like the TGC system, the price for green certificates is determined as the equilibrium price between supply and demand for certificates. Fluctuations in the supply of certificates will cause fluctuations in the TGC price.

The electricity price and the TGC price are negatively correlated. The supply bids of green certificates will be low if the level of the electricity price is high during a longer period. This is due to the fact that the RES-E producer receives both the electricity and the TGC prices in order to cover his cost. If the electricity price is high, he can sell certificates at a low price in order to cover his cost, and vice versa. This is one of the forces of a TGC system; the risk from the electricity price is counteracted by fluctuations in the TGC price. However, since the electricity price is based at short-term sales and the TGC market is based at long-term deployment, the TGC price does not react to short-term fluctuation from hour-to-hour, but rather to long-cycle fluctuations.

The TGC price may also fluctuate due to changes at the demand side, e.g. if the green quota has a lower growth than expected, the TGC price will also be lower than expected. In most cases, uncertainty about the green quota is regarded a political risk (see below). Finally, wrong determination of the penalty price may create a price-cap on the certificate price that the TGC price will frequently hit.

Since the TGC system is new, it is too early to estimate how volatile the TGC price will be. Therefore, estimation of volatility must at present be done on the basis of power prices and common sense. In addition, the TGC market might be a national market, a common EU market or a market made up of cluster of Member States. The larger the market, the smaller the volatility, i.e. a national market might have a relative large volatility, whereas an EU-wide TGC market will be more liquid and have more stable prices.

A national market or a cluster of few small national markets might have dominating technologies that determine the TGC prices in most cases. For example, in a windy year there will be a large supply of RES-E and thereby a low TGC price, i.e. the fluctuation of wind power production implies fluctuations in the TGC price. In a EU wide market, a technology in a local area will not dominate the price as much as in a national market. For example, if it is a calm wind year in Northern Europe it might be a windy year in Southern Europe. Thereby, the lack of supply from one area is compensated by a larger supply from another area.

Fuel price
Most RES-E technologies do not use fuels. However, for those renewable energy technologies that do use fuels, fluctuations in the prices of these may cause risk. This is for example the case for biomass plants that purchase wood pellets. If the price of the wood pellets follows the world market price for other fuels, e.g. oil, then fluctuations in the oil prices will cause fluctuations in the price of wood pellets. The fluctuation in fuel prices can also come from local conditions. If a biomass plant uses straw, then the price for straw might depend on the supply and quality of the straw. On one hand, in a good harvest year there may be plenty of good straw, i.e. excess supply with a low price. On the other hand, in a bad harvest year the price may rise due to excess demand. The volatility for local fuels is very hard to estimate.

4.3.3 Technological risk

Technology risk covers all technical risks related to the costs and availability of the plant. For example, the risk of a forced outage of a plant can be a significant component of the investor's financial risk. Both the probability of an outage, the timing and the duration of the outage will affect the total risk. The probability of a transmission line being down for a given period of time is a similar type of risk.

A lack of general technological knowledge about renewable energy might form a risk for national investment projects, instead of for one specific project. The Spanish Plan for the Promotion of Renewable Energy[29] identifies a number of technological risks that seem to impede

[29] Issued in December 1999 by IDAE (Institute for the Diversification and the Saving of Energy).

Spain to achieve its target of 25% renewable electricity. One is technological knowledge of technological options that are important for Spain, in combination with a shortage of skilled engineers. Secondly a lack of knowledge on grid connection technologies, in particular for wind turbines, which included stability, quality and safety issues.

The technological risk factors are investment costs, fixed and variable O&M costs, availability, technical lifetime and yearly production. Apart from yearly production volume, the technological risk factors[30] will be smaller for more mature technologies. In fact one of the characteristics of a mature technology is that it has high availability and little risk of unforeseen repairs, i.e. that the O&M costs are predictable.

To make a volatility survey manageable, one can bundle the technologies into three classes according to their technological maturity and two classes of site dependency. The three maturity classes are equivalent to phases.

1. Market phase. A mature technology is characterised by the following:
   - Proven performance: the reliability and durability of the technology is high, and the high values can be 'proven' by referring to a considerable number of sites, where the technology is already used.
   - The technology is produced in relatively large numbers with the use of industrial mass production techniques.
2. Introduction phase: There is only a short track record, i.e. only a limited number of plants using this technology.
3. Pioneer phase: The technology is still in the field-testing phase, and the investment will constitute one of the first full-scale realisations of the technology.

The two classes of site-dependency are:

1. Standard technology: these are technologies with a large share of standard components that are site-independent. An example is onshore wind turbines where the site-independent costs, i.e. the price of the wind turbine exclusive foundation, land, electric installation and grid connection constitutes up to 80% of the investment costs (Redlinger, Andersen, et al. 2002).
2. Individual technology: these are technologies that have a relative large share of site dependent components.

The larger the share of the site-dependent costs (so-called non harmonised costs) of the investment costs, the larger the risk, because these site-dependent costs can vary more than the site-independent costs. Firstly because unforeseen conditions at the site can emerge during the construction period, and secondly because a more volatile market will exists for the site-independent investment costs.

Below, we will discuss the main factors causing technological risks for individual cost components.

Investment costs

Many of the RES-E investments are capital-intensive renewable energy projects. Therefore, fluctuation in the investment cost may have a considerable effect on the revenue of an investment. In addition, they are up-front costs and, in many instances, sunk costs. Investments in well-known, mature energy technologies that use standard components have more or less predictable investment cost, e.g. present wind turbines. The investment costs for these technologies have been stable[31] for a couple of years and are well known, i.e. there is little uncertainty connected to investment in mature technologies. However, more immature technologies or energy projects that are made up of individual components often have fluctuations in the final investment cost, e.g. present PV. There technologies might not have found the true investment cost

[30] Investment costs, O&M costs, availability, technical lifetime.
[31] Or followed a stable development.

level yet and unpredictable changes might occur. Therefore, the investment cost for these technologies are more risky.

O&M costs
Operation and maintenance costs (O&M costs) cover insurance, regular maintenance, repair, spare parts and administration. Administration, insurance and regular maintenance will probably be quite predictable, where as repair and related spare parts will vary more.

For most RES-E technologies the O&M costs form a smaller part of the total costs. In addition, the amount of O&M cost often depends on the physical load of the plant. Maintenance costs are generally very low while the plant is brand new, but they increase as the plant ages. In addition, well-known, mature energy technologies having standards components that have been tested for many years have more or less predictable O&M cost. Whereas immature technologies often have more fluctuations in the O&M costs.

There is a close connection between the risk factor 'Technical lifetime' and the O&M costs, because increasing the money spent on repair and spare parts can prolong the lifetime. There also exists a close connection between the risk factor availability and the O&M costs, because the availability expresses the time spent on maintenance and repair, where as part of the O&M costs as mentioned above is the costs spent on maintenance and repair.

Technical and actual lifetime
The technical life lifetime is a useful economic compromise that is used to guide engineers who develop components for the plants. Their calculations have to prove that their components have a very small probability of failure before the technical lifetime have elapsed. The actual lifetime of a plant depends both on the quality of the plant and the load (e.g. local climatic conditions for wind turbines such as the amount of turbulence at the site).

Uncertainty about the lifetime of a plant may not only cause uncertainty about how long you can earn a revenue from the plant but it also cause uncertainty about the O&M and investment cost needed. The technical lifetime may be prolonged as described above.

Availability:
The availability factor for a 'normal' power plant is the probability that when you need it to be working, it is ready. For wind turbines, the same words are misleadingly used to describe something entirely different. If a wind turbine is in good mechanical shape and produces power whenever the wind blows, then its availability factor is said to be 100%. Therefore, the availability factor for a wind turbine means the probability that power can be produced if the wind is blowing.

The 'general' availability factor is always below 100% due to revisions of the power plant, drop out of the plant or other reasons that the plant is taken out of operation for a certain time period. The larger the availability of a plant, the longer the period that the plant can generate revenue. Therefore, fluctuations of the availability factor directly cause fluctuations in the revenues.

Construction time:
Uncertainty and fluctuation in the construction and lead time before the production can start causes fluctuations about the planned date when the plant will start to generate revenue.

Annual production / Volume risk:
The electricity industry is subject to short-term energy supply and laws of physics. Fluctuations in the production volume are in most cases caused by fluctuation at the input side. For some generation units the amount of input fuel available is stochastic. Wind turbines and hydro power

plants are the most prominent examples. However, also biomass based on waste, wood, straw etc., can experience fluctuations in available input during e.g. an annual period.

Fluctuations in the efficiency of the plant may also create fluctuations in the production volume. This partially stochastic volume on the supply side in combination with the fact that electricity cannot currently be economically viably stored, implies that the revenue from a RES-E investment can vary in a complex manner, which can be very different from what is known from other investments. Variation in annual production is only important for more or less uncontrollable technologies, i.e. small-scale hydropower, wind power and PV.

4.3.4 Political risk

Political risk is the risk of changes in the system imposed by the government on the owners of capacity. Most renewable energy installations will need some form of support. Both for renewable and non-renewable producers, the politically chosen market design represents a significant financial risk.

Production support

Fluctuations in the level of the support or changes to the policy that determines technology eligibility may cause fluctuations in the revenue of the RES-E producer.

A TGC system is a market-based system for production support to RES-E. The design of the TGC market and the demand for certificates (the green quota) are politically determined. Unexpected changes of the quota will inevitably cause fluctuations in the TGC prices and thereby also in the revenue of the producers. Likewise, a change of market design will cause fluctuations. Currently, there are uncertainties about if and when national TGC markets are going to merge to common markets, and if other support systems will run parallel with the TGC system and thereby interfere at the price setting at the TGC market.

Investment support

Investment support can be given in various ways, e.g. tax deduction, direct support, soft loans, and favourable depreciation arrangements. Any change in the present system will cause risk.

Planning time and permissions

As described in the lead time section (Section 4.1), the planning time contains many factors that may fluctuate and thereby induce risk to the investment. The size of the fluctuations varies from country to country and from technology to technology. A crucial point in the planning phase of a project in the renewable energy sector is obtaining the necessary permits from local authorities. There is a risk described by the difficulties of obtaining permits. This can both be described by fluctuations in the lead time and in the transaction cost.

4.3.5 Interpretation of risk

In order to analyse the effects of the different risk factors for a given investment, it is useful to focus on the factors that are most important for the investment and that are hard to predict, i.e. the factors that bring most risk to the investment.

Obviously, different technologies face the risk factors differently. Therefore, there is not a unique way to order the factors according to importance for the investment and how predictable they are. It depends on the technology, the location, the country, the policies, etc. Again the challenge lies in simplification and in creating a suitable framework for analysis of which factors each investor has to pay attention to.

Here we have used a comparative presentation with focus on the relation between the factors. We look at two sides of the factors - importance and predictability - both rated at a scale between 1 and 5. The ranking for importance is 1=very important, …, 5=not important, and for predictability is 1=very uncertain, …, 5=certain.

A graphic presentation of these factors can be seen in Figure 4.6, which indicates the relations between importance and predictability.

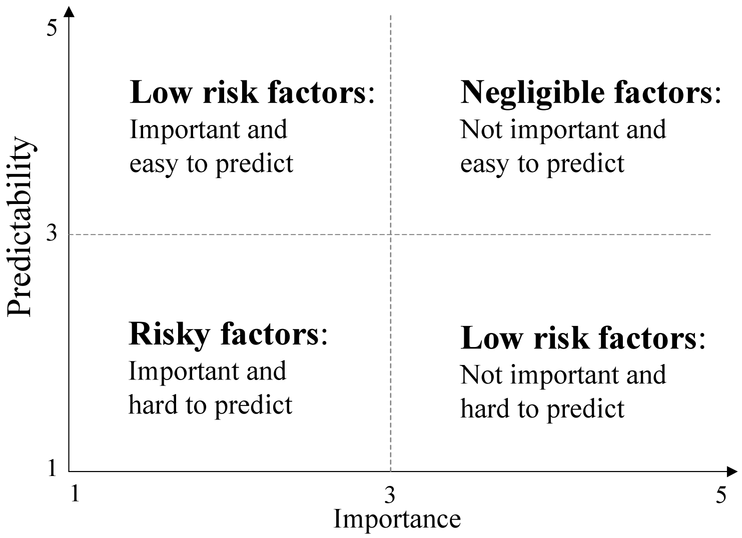


Figure 4.6 *Characterising risk factors*

In order to compare the different factors, we split the figure in four parts. Each part defines a degree of risk connected to the investment.

- The most important and unpredictable factors defines the most risky parameters as these that are within the lower left corner [1;1]x[3;3] at the figure. These are the factors that are important for the investment and that have fluctuations, i.e. that are hard to predict.
- If a factor is important for the investment and at the same time easy to predict (upper left square in Figure 4.6 we define it as a low risk factor, i.e. only a little amount of risk is connected to the factor.
- If a factor is not important for the investment and it is easy to predict (upper right square in Figure 4.6) we define it as a negligible factor. In this case it does not create any significant risk for the investment. Therefore, these factors can in most cases be neglected in a risk analysis of an investment project.
- If a factor is hard to predict but has a low importance for the investment (lower right square in Figure 4.6) we define it as a low risk factor. Even if the factor faces heavy fluctuations these fluctuations will only have a small impact on the revenue from the investment. Therefore, it will only contribute with a low risk segment to the investment.

In (Skytte et al., 2003), this framework is further elaborated for different technologies in different countries.

4.4 How to reduce risk?

Market risk

In general, market risk holds all risks related to the currently chosen market structure. There is a common interpretation of how to cope with market risk with respect to investments in different renewable energy technologies. As for all kinds of risk it is a matter of hedging, i.e. the investor should in one way or the other have a kind of ‘insurance’ that reduce the risk.

In defiance of this common interpretation there are different ways to cope with market risk. You can either use market mechanisms to reduce market risk, or you can reduce the influence of the market and thereby also the influence of market risk. In both cases the investor transfers the risk to a third party, either by using the markets or with help from the political planner.

In the former case, the investor has to be active by making financial hedging strategies, e.g. forward and futures contracts. In the later case the political planner 'removes' the market risk from the investment by guaranteeing the income, e.g. by long-term power purchase agreements (PPA), fixed feed-in-tariffs, guaranteed loans, etc. In other words, the later case reflects the situation where the market based system is replaced by a political determined fixed price system. In this situation, the market risk is transferred to political risk, i.e. market risks become negligible whereas risk connected to subsidies and other political risk factors become important.

A market based subsidy price is determined by the supply and demand. If there is a dominating technology, e.g. wind power, then a calm wind year implies a low supply and thereby a higher market based subsidy price. In other words, the total supply of RES-E is negatively correlated with the market based subsidy price, i.e. price and volume risks are negatively correlated, which create a stable income for the producers. This is no longer the case if fixed feed-in tariffs replace the market-based prices. Then the volume risk matters more for the investor than it does when the prices counteract fluctuations in the volume.

It is therefore ambiguous if a fixed price system has lower total risk than a market-based system. Therefore, it should be studied carefully before the investor makes lobby work in order to get a change of the subsidy system from a market-based one to a fixed price system or vice versa.

However, if one recognises the market based system there are plenty of mechanisms connected to this system that can reduce the market risk. In any case, it is important to have good information from and about the power market and power exchanges. In addition, market analyses and other studies can help the investor to become better at predicting fluctuations at the market and thereby reduce the risk. Hedging by financial instruments such as swaps, futures, etc. is effective risk management that uses derivative market mechanisms. These mechanisms are already present at most power exchanges, e.g. at Nord Pool power exchange, and they are very popular, i.e. these derivative markets are stable and liquid markets.

Technological risk

Technology risk covers all technical risks related to the costs and availability of the plant. As discussed in previous sections, the use of proven and mature technologies implies lower technological risk than using immature technologies. In addition good management and technical skills reduces the technological risk.

Therefore, education, organisation and obtaining of technical skills are some of the overall ways to reduce technical risk. Standardisation and independent tests of the technologies also reduce the risk.

For risk connected to *investment cost* the following measures reduce risk:

- Cost studies and proper planning give a low standard deviation for the expected cost.
- Contract management. Transfer the risk connected to fluctuations in investment cost to the other parties of the contracts, e.g. the builder of the plant.
- EPC (Engineer-Procure-Construct) turnkey and equipment supply contracts (or projects). Normally, this is an EPC construction with single source responsibility and a broad shifting of risk. The preferred format for power plant construction is the single source EPC contract. This appears to give the owners/developers a fixed price with an assured delivery date. It has proved to be an attractive format for lenders.

For risk connected to *O&M costs* the risk can be transferred to a third party by outsourcing of O&M costs, or long-term contracts for O&M costs. Some constructors of wind turbines are starting to do long-term maintenance contracts that last 10 years.

For risk connected to *annual production* the goal is to be as good as possible to predict the annual production and, if this is not enough, to transfer the risk to a third party. Therefore, there are two ways to reduce the risk connected to the annual production:

- Good wind, hydro, and sun forecasting and measurement.
- Insurance though financial contracts (derivative markets) that insure an expected revenue in defiance of fluctuations in the annual production.

Availability of a plant is closely connected to the O&M costs of the plant. The way to reduce risk connected to availability is therefore the same as for O&M, i.e. good O&M management skills.

Political risk

Political risk is risk of changes in the system imposed by the government on the owners of capacity. Therefore the political authority plays a key role in reducing this risk. For a single investor this seems hard to do when planning an investment. However, some of the political risk can in general be coped with. Investors can form organisations that do lobby work on behalf of the investors. For the lobby organisation this requires good understanding of laws and decrees and clear goals. Most of the political risk can be reduced if one is able to get clear, long-term political commitment and legislation. In addition, much political risk can be eliminated through systems based on civil contracts for power rather than relying on future political will.

On one hand, the political risks are for all support systems connected to the future conditions on which RES-E producers that get the support. On the other hand, the political risks differ between the different support systems with respect to level of payments or level of deployment, e.g., in a feed-in tariff system it is the future level of the tariff that matters. In a TGC system it is the future quota that matters[32]. In both cases long-term political commitments reduce the risk and create more stable conditions for the revenue from RES-E and thereby also for investments in RES-E technologies.

A TGC system has another kind of risk, namely the risk connected to a politically determined price cap, i.e. the penalty price and the minimum price. The penalty price is used in order to force the consumers to purchase the TGCs. However, the penalty price also sets a maximum price for the TGC. Likewise a minimum price can be introduced in order to guarantee the RES-E producers a minimum support. In order to reduce the risk connected to a change in the level of the penalty price or the minimum price, it is important to have long-term commitments in this area too.

Political risk can also be connected to permissions from local authorities or councils. It is important to reduce the risk by commitments for fixed deadlines and permission routines. The lobby organisations can try to require this. For the risk connected to local areas, the investor and/or the organisation can try to get local support from the inhabitants in the municipality. In addition prior consultation with planners and clear guidelines from planners can speed up the permission process.

[32] The risk connected to the TGC price is a market risk and not a political risk.

5. POLICY SCENARIOS

This chapter presents the scenarios developed within the ADMIRE REBUS project. The chapter starts with some considerations on trade in the current fragmented market for renewable electricity in the European Union.

5.1 Trade in a partly harmonised market for renewable electricity

How can trade in the EU market for renewable electricity take place, and what will change in the coming years? Although many developments depend on what decisions will be taken by the Commission and Member States on the harmonisation of support schemes, something can already been said. The term harmonisation is often directly interpreted as the creation of a uniform support framework for RES-E in the EU. Although this can be the final result of harmonisation, there are many stages in between (Van Sambeek, 2002). The degree to which harmonisation is implemented determines how trade in the EU electricity market takes place.

1. The first stage, for which preparations are already being made, is to provide a common framework for the registration and verification of renewable electricity. The RES-E Directive requires all Member States to issue 'guarantees of origin' (GOs) as of October 2003. Note that GOs are not necessarily tradable, although they could facilitate trade.

2. Next, these GOs can be used as a basis for monitoring the achievement of the EU targets. For this purpose, agreement is needed on how to account for the consumption of renewable electricity, because the GOs reflect electricity production and the targets are specified as a share of consumption. One way to do this, is by requiring that the receipt of production support in Member States counts as consumption of renewable electricity by that Member State, and thus is administered through the GOs. Harmonisation on this level just ensures that renewable electricity is not supported twice, and prevents double counting of consumption for achieving the targets. For this reason, it is essential that GOs not only give information on the origin of the electricity, but also on the support schemes that have been used, including investment support.

3. One step further will be that countries mutually recognise their GOs as a basis for trade in renewable electricity; in this case, a (fragmented) international TGC market evolves. This does *not* automatically imply that all countries have the same support scheme. In theory, the combination of green certificates and for instance feed-in tariffs is also possible. In this case, producers could sell their electricity on the national as well as the international market. On the national market the producer can accept feed-in tariffs, provided that the certificates are then transferred to the (government) organisation that has paid the feed-in tariff.

4. Harmonisation of the support *level* is the logical next step, because this prevents distortions of the market, e.g. the emergence of trade flows only caused by differences in support levels. Note that this is more complicated than it seems at first sight. The net support level - received by the RES producer - is not always clear, because depending on the type of support scheme, different actors play a role and may receive part of the support. Moreover, this might also require a harmonised level of investment support across all EU countries.

5. Finally, a completely harmonised market is achieved by introducing a common support framework (and level of support) across Europe. Note that this does not necessarily imply that the framework is based on quota and green certificates; it could also make use of feed-in tariffs or bidding systems.

In 2005, the Commission will present a report on the experience gained with the different support schemes in the Member States. This report may be accompanied by a proposal for a Community framework for RES support schemes, allowing for a transition period of at least 7 years in order to 'maintain investors' confidence'.

One way to implement this transition period could be to distinguish between existing and new capacity. Suppose that the Commission takes a final decision on harmonisation in 2007, e.g. two years after publication of the evaluation report, and suppose that national governments have another two years time to transpose their national legislation. Then, all new capacity installed as of 2010 would fall under the harmonised community framework, whereas capacity installed before this date would have the right to make use of their domestic schemes for at least another 7 years, e.g. until 2017 or beyond.

5.2 Policy scenarios for the future

From the discussion above on the way towards harmonisation we can set up three main scenarios for the future policy and market harmonisation. These scenarios are further described in the next sections.

1. Continuation of present policies
2. Clustered Europe
3. Harmonised Europe.

The scenarios differ along two dimensions, as illustrated in Figure 5.1. The level of co-operation is reflected in the extent to which Member States use international trade in a (partly) harmonised policy context. The ambition level is implicit in the size of the quota or the level of the feed-in tariffs, and differs by country.

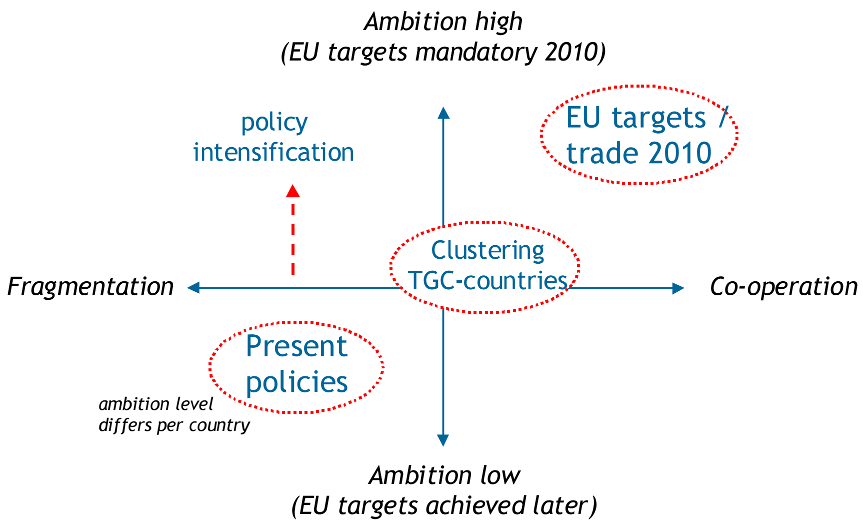


Figure 5.1 *Scenario overview*

5.2.1 Scenario I: Continuation of present policies

In Scenario I, the Commission decides not to impose any harmonisation of the support framework. Moreover, the indicative targets as formulated in the RES-E Directive continue to merely serve as a reference for individual governments. The Guidelines for State Aid remain the most important framework for Member States to decide on the instruments and amount of support for

RES-E[33]. Nevertheless, Guarantees of Origin are implemented conform the RES-E Directive, and are used as a basis for international trade as described in Stage 3 of Section 5.1.

National governments continue their 2002 policies and measures, and proceed with new policies as planned in 2002. Countries that already recognise each other as trading partners (for instance on the basis of reciprocity), will continue to do so. Producers can opt for international trade when this means that they renounce their domestic support scheme, or when they are not eligible for domestic support.

In this scenario, investors compare the support schemes and other conditions in different Member States as far as they are eligible for it, and choose the most suitable trading partners. They trade certificates (GOs), except in those cases where a government explicitly requires physical delivery of the electricity.

This scenario is a direct translation of the policy data and the results of the questionnaire on planned and expected policies. Section 6.1 evaluates whether the EU targets can be achieved under current and planned policies.

5.2.2 Scenario II: Clustered Europe

Scenario II represents a situation that is in many aspects similar to Scenario I. In October 2004, the Commission publishes its first report on the Member States' progress towards achieving the indicative targets as formulated in the RES-E Directive, and proposes to give these targets a mandatory status. At that time, the prospects for harmonisation of the support framework, on which the Commission is due to decide in 2005, are not very clear. The validity of the Guidelines for State Aid, however, is expected to be extended beyond 31 December 2007.

National governments thus have a clear incentive to achieve their targets, either by supporting renewable electricity production in their own country or by trading renewable electricity. This favourable attitude towards trade motivates groups of Member States to open their markets for each other. Initially, in 2007 only those countries that were already using a market-based system open their markets. This concerns Belgium, Denmark, Italy, Sweden, and The Netherlands.

The TGC market grows and thus becomes more attractive to other EU Member States. In 2009, a number of countries join the system, which means that they open their markets and comply to the harmonised system as agreed within the cluster.

- Finland has a large export potential and has experience in trading with other Scandinavian countries in the Nord Pool power exchange.
- UK has a national TGC system already, and decides to open their borders.
- Ireland has a large export potential and is expected to replace the AER with a market-driven support scheme.

Just as in Scenario I, trade takes place on the basis of green certificates (based on GOs). By 2010, the countries in the cluster will have established a completely harmonised TGC market. Investment support is not harmonised; all countries design their own policies within the framework of the Guidelines for State Aid. This scenario is evaluated in Chapter 7.

[33] For renewables, investment support is maximum 100% of the *eligible* costs, e.g. the 'extra investment costs necessary to meet the environmental objectives'. In this case, the installation is not entitled to receive any further support.

5.2.3 Scenario III: Harmonised Europe

In October 2005, the Commission publishes its report on the experience gained with coexistence and application of the different support mechanisms within the EU. In this report, it concludes that there is reason to introduce a community framework for support schemes, and it proposes the introduction of an EU-wide system based on quota obligations and tradable green certificates. As quota, the indicative targets (RES-E Directive) are taken and thus these are given a mandatory status. In 2007, the RES-E Directive is amended, and Member States are given two years time to transpose their national legislation. Thus, all new capacity installed as of 2010, falls under the harmonised community framework, whereas capacity installed before this date has the right to make use of their domestic schemes for at least another 7 years[34]. Producers in a feed-in tariff or a tender scheme have a choice whether they participate in the harmonised TGC market or stick to the feed-in tariff they were previously entitled to. Producers that previously participated in a national TGC market do not have such a choice, but have to adjust to the new, larger market.

Investment support is not harmonised, due to the subsidiarity principle. The provisions applying to investment aid for RES-E, as stated in the Guidelines for State Aid are extended beyond 31 December 2007. Trade in the years towards 2010 takes place on the basis of certificates (GOs), but the eligibility of producers for support schemes abroad is restricted to those cases where governments allow this.

[34] In those cases where currently available policy data indicates a longer operational period, e.g. feed-in tariffs that are guaranteed for 10 years.

6. MEETING EU RENEWABLES TARGETS

In this chapter, we assess whether the European and national 2010 RES-E Directive targets might be reached by applying the existing policy schemes at least until 2010. If the continuation of present support policies is effective in reaching such targets, we may still wonder if the same degree of success could be obtained at a lower cost for society with a different support framework (i.e., with a harmonisation of policies combined with a TGC scheme), taking into account that, at the end, it is either consumers or taxpayers who pay.

Note that it is not before October 2003 that the European Commission will evaluate to which extent the national governments have transposed the directive into their national support policies. This would be the most appropriate moment for an evaluation of national efforts. In this sense the ADMIRE-REBUS assessment based on those policies planned or implemented by early 2003, should be regarded preliminary. Member States still have time to revise their support schemes or introduce new ones.

6.1 Continuation of present policies

We compare the total consumption of renewable electricity, including imports, in the different Member States in 2010 with their respective target in that same year, under the scenario Continuation of present policies as described in Section 5.2.1. A positive difference means that the country could comply with its indicative target by applying its current support scheme. A negative difference implies the opposite conclusion.

An important differentiation should be made. On the one hand, by subtracting the 2010 target for each respective country from their (simulated) consumption in that same year, either a surplus or a deficit of GWh for each country comes out. We will call this *absolute compliance* (or lack of it). However, the potential, the realised supply, the policy and the targets differ per country. It is therefore more interesting to identify how large the deficit or the surplus of the country is, when compared to its own target. This reflects better the degree of effort the country will have to make in order to comply with its own targets. We call this *relative compliance*. The following subsections show results concerning both absolute and relative compliance.

6.1.1 Compliance in absolute and relative terms

The model results indicate that at baseline electricity market conditions[35], the EU as a whole does not reach its target in 2010. Divergence between the realised supply and the linear interpolation of targets takes place during the 2000-2010 period. Therefore, in 2010 the deficit is projected at almost 120 TWh. The consumption of renewable electricity in the EU-15 would amount to 543 TWh, corresponding to a share of 17.8% in total projected consumption, instead of the 22% target. If we take a look at the absolute compliance of individual countries within the period, we can see that only two countries are projected to comply with their indicative targets (Figure 6.1). These are the UK and the Netherlands. As we will see in next subsection, if its deficit is compared with its target, Austria could also be considered to be in compliance with the targets.

On the other hand, there are Member States showing a high absolute non-compliance. In descending order, these are Italy, Spain, Germany and Sweden. Intermediate rates of non-

[35] Baseline electricity market conditions are a total electricity demand of 3,054 TWh in 2010, with overcapacity continuing and a relatively low carbon premium, resulting in relatively low wholesale electricity prices of 3 ct/kWh on average (see Section 2.2).

compliance can be seen in Finland, France and Portugal while relatively low rates of absolute non-compliance are experienced by Ireland, Greece, Denmark, Belgium, Austria and Luxembourg.

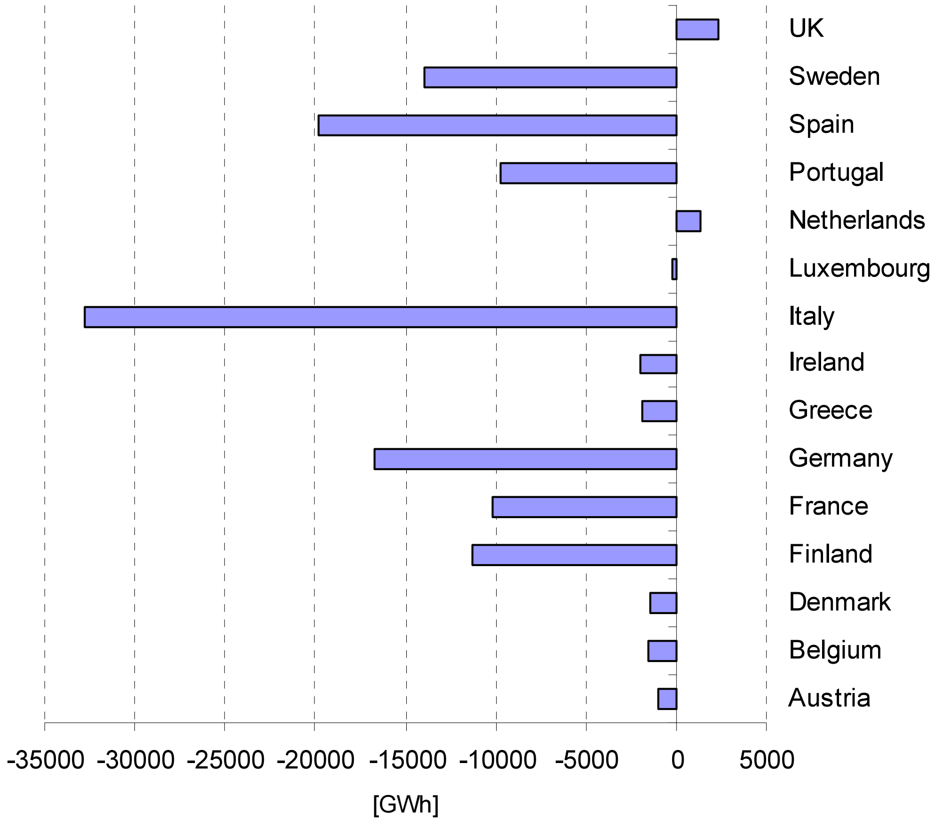


Figure 6.1 *Absolute compliance in different Member States in 2010; Continuation Present Policies scenario*

The actual costs of production for achieving 543 TWh renewable electricity production in the EU in 2010 are 4.7 bln €. The total additional government and end-user expenditures amount to 9.4 bln € in this year, and this cost figure is higher because it takes into account the producers surplus. The total additional government and end-user expenditures are calculated based on the levels of feed-in tariffs paid in various countries, as well as the equilibrium prices in countries using a domestic TGC system etc, see also Section 2.3.

Relative compliance

By continuing with their present policies, the European Union as a whole would not reach its 2010 targets. The consumption in 2010 would only be 82% of the target for that year. When the absolute levels of (non) compliance are compared with indicative targets for each Member State, a slightly different picture emerges (Figure 6.2). The Netherlands and the UK are above their targets, but note that when total projected consumption in 2010 is compared to targets in 2010, the UK is not the first compliant country (as was the case in absolute compliance), but the second country, right behind the Netherlands. The change in position when moving from absolute to relative compliance is also visible in non-compliant countries. For example Austria's performance is projected to lag behind the target by a relatively small margin in 2010 (relative compliance is 98,2%).

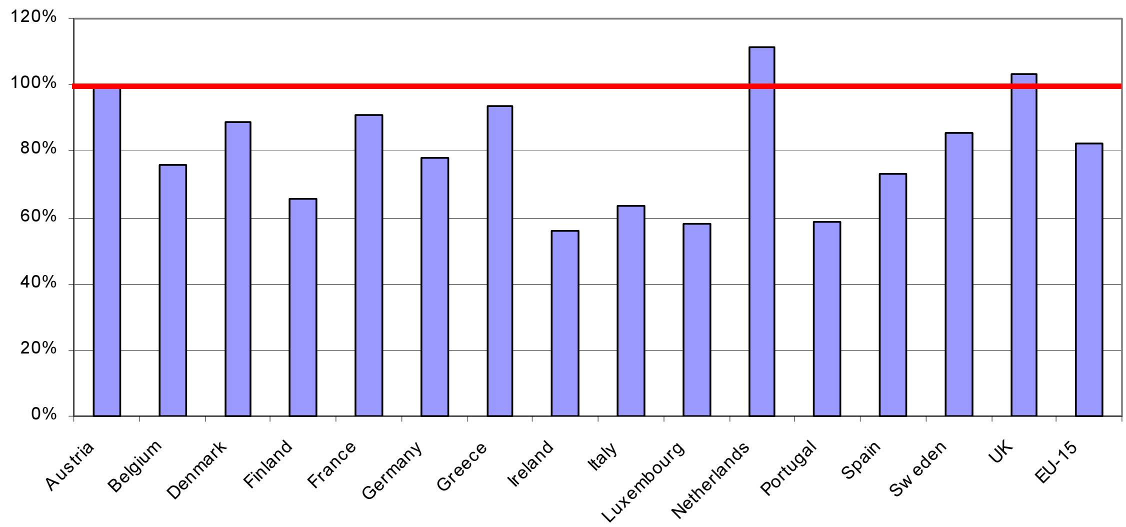


Figure 6.2 *Relative compliance: consumption of RES-E compared to targets in 2010 under scenario Continuation of Present Policies*

In relative terms, the country farthest from its 2010 target would be Ireland (56%), followed by Luxembourg (58%) and Portugal (60%). On the opposite side, large absolute non-compliants behave better in the relative scale, although they are still far from their own 2010 targets: Italy (63%), Spain (74%), Germany (78%) and Sweden (86%). Apart from Austria, the countries that do not comply with their targets but are closest to them are: France (91%), Denmark (89%) and Greece (87%).

A sensitivity analysis on the commodity price of electricity, lead times and other factors determining the amount of potential available on the market due to non-technical factors, is summarised in Figure 6.3. It confirms that for most countries, achieving the EU target is not an easy task. Moreover, it shows that support policies - the main factor not varied in the sensitivity runs - are the key factor in bridging the gap between target and realisation. In Chapter 9 further sensitivity analysis is presented.

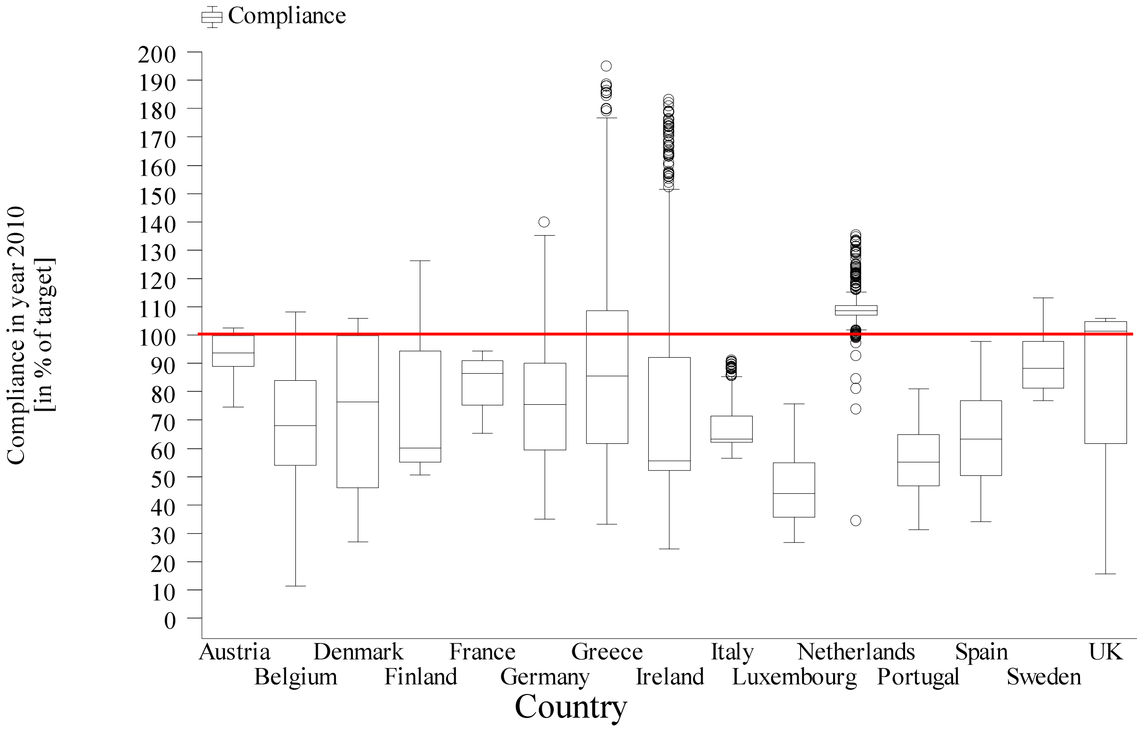


Figure 6.3 *Sensitivity analysis on relative compliance in 2010; continuation of present policies*[36]

6.1.2 Country overview

As mentioned before, the Netherlands, the United Kingdom and probably Austria are expected to achieve their targets in this scenario. These three countries are using completely different types of policy instruments. Austria makes use of feed-in tariffs, the Netherlands uses a mixture of feed-in tariffs and a fiscal incentive that stimulates voluntary demand[37], while the UK has designed the Renewables Obligation as a path of quota leading to the target in 2010, with a sufficiently high penalty.

It is worth noting that, in the case of the Netherlands, domestic supply would only achieve 71% of the target for year 2010. As shown in Figure 6.4, the rest would be achieved through imports (actually leading to an overachievement). This is an effect of the Dutch approach. First the consumer market was stimulated using fiscal incentives for which imports were eligible as well. The consumer market grew very fast, but local production of renewable electricity did not increase, while the imports did. In 2003 the system changed, but still left a smaller fiscal incentive on imports. The ultimate effect, as shown by the model, could be that The Netherlands is importing from countries that will not be able to reach their own targets. Obviously, this is not very likely, and clearly indicates the uncertainty surrounding the achievement of the Dutch target.

Furthermore, it is important to observe that Ireland is also a special case, in that the current policy - AER 6 - is only defined until 2005. Therefore, a ‘policy gap’ in the period until 2010 is the main reason for Irelands non-compliance. The targeted amount of MW to be achieved by AER6 in 2005 is obviously not sufficient for achieving the target. Additional analysis, described in the

[36] The figure is a box-and-whisker plot. The upper and lower horizontal line (the *whiskers*) represent the extreme values of the simulated results. The *box* represents the space between the 25th and the 75th percentile of the simulated cases, i.e. 50% of the results are located within this box. The horizontal line within the box indicates the median.

[37] Changes of in the direction of a complete feed-in system have been announced in September 2003.

next sections, shows that Ireland is not expected to have any problems achieving the target in 2010. On the contrary, in a scenario of harmonised quota, Ireland is likely to become an important exporter of renewable electricity or green certificates.

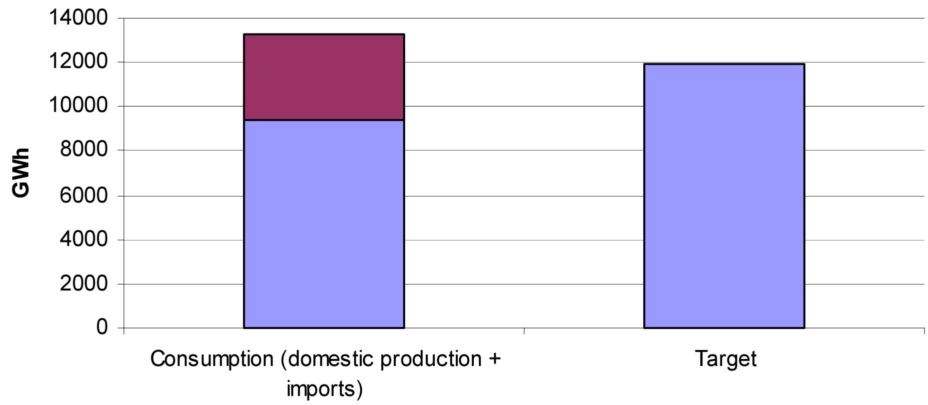


Figure 6.4 *The Netherlands in 2010 Continuation of Present Policies scenario*

In principle, a quota obligation offers the best chances of achieving a set quantity of renewable electricity production. Still, the model results show that the other countries using a quota obligation have difficulties achieving their quota. Different reasons can be found for this.

- Although Belgium has an ambitious policy and the Walloon and Flanders regions are using high penalties of 10 and 12.5 ct/kWh respectively, a very large growth of renewables deployment is required in a short period, and lead times are too long. In the Continuation of Present Policies scenario, Belgium achieves its target in 2012.
- For Denmark, where we have assumed the introduction of the announced TGC system in 2004, not enough potential appears to be available at a cost price below the penalty price of 3.6 ct. The country is expected to achieve the EU target in 2015. In Section 8.1, the Danish situation is analysed to a larger extent, and a comparison is made with the situation that the current feed-in tariffs are maintained.
- In Sweden, the penalty is relatively low at 2.2 ct/kWh, which makes export to a country with a higher support level (the Netherlands) attractive for Swedish producers.
- The 2% quota in Italy does not increase over time to achieve sufficient growth in production, required to meet the 12.5% EU target. Note that the quota does not have to reach the 12.5%, because Italy has a substantial contribution of existing large hydro capacity, as well as capacity built under the feed-in tariff CIP6/92.

Therefore we can observe that not the type of support scheme but rather the way it is implemented and the level of support determine its effectiveness (although the efficiency might differ). In addition, it is worth noting that all countries mentioned above have only recently implemented a TGC system, or are planning to do so in the near future. This means that it is in fact too early to evaluate the functioning of these support schemes.

We will now briefly discuss the other countries in alphabetical order[38].

- Austria is likely to achieve the EU target by an increase in particularly the contribution of biomass CHP (forestry residues and energy crops). The contribution of large hydro is stable. An increase in the production based on small hydro installations and wind onshore is also foreseen.
- In Finland, the fiscal incentive induces a growth of biomass CHP based on forestry residues. The level of the incentive (0.42 ct/kWh - 0.69 ct/kWh) is not sufficient for a substantial growth of other technologies, and therefore Finland is not likely to achieve the EU target

[38] In Section 3.3 the support policies used by different Member States are described more extensively.

under current policies. However, the potential for wind onshore and biomass CHP and co-firing is certainly available at a reasonable cost; increasing the support level to maximally 2.7 ct/kWh would be sufficient for achieving the target.

- For France, the feed-in tariffs induce a 38% growth of renewables production between 2000 and 2010. Although France does not achieve its target in the Continuation of Present Policies scenario, its chances of achieving it are quite good, once, for instance, the maximum amount of MW to be installed under the feed-in tariffs is increased. France is further discussed in Section 8.2.
- Although the production of renewable electricity in Germany almost doubles in the period 2000-2010, achieving the - ambitious - target requires that production increase with a factor 2.4. Of course this is directly related to the expectations regarding the growth of electricity consumption in Germany. The main contribution comes from onshore wind energy. Striking is that wind offshore does not take off, despite the ambitious plans and targets set. It appears that the level of the German feed-in tariff is slightly too low, in combination with the fact that there are hardly any potentials at the most favourable sites (wind regime higher than 9 m/s and closer than 40 km to shore). Germany is discussed in more detail in Section 8.3.
- In Greece, a combination of investment subsidies and a feed-in tariff leads to a substantial growth of renewable electricity production with factor 2.5, corresponding to 87% of the target. Fastest growing technologies are wind onshore and biomass CHP - wheat, oil crops and forestry residues.
- For Luxembourg, the available potential is the limiting factor. Feed-in tariffs induce growth from wind onshore and biomass CHP (energy crops), but it is very difficult for Luxembourg to achieve the EU target without imports.
- In Portugal, feed-in tariffs cause a steady growth of 83% renewable electricity production in the period 2000-2010. The largest growth is found in biomass CHP (forestry residues) and waste combustion. The reason that Portugal is not likely to achieve its target in the current analysis, is that the expected growth in electricity demand is very high, which leads to tripling of the 2000 production level required for achieving the EU target.
- Similarly, for Spain the feed-in tariffs (fixed premium) almost cause a doubling of production in 2010 compared to 2000. Growth mainly comes from biomass CHP and co-firing; wind onshore shows only a limited growth.

Finally, a remark should be made about the contribution of offshore wind (see also Section 7.2). Model results show a lower realisation of this technology under current policies than what is generally expected. If the EWEA target of 10 GW would be achieved in 2010 (without replacing any production from other technologies), the EU production of renewable electricity could increase from 82% to 86% of the target.

6.1.3 Possible strategies

The main conclusion is that a continuation of present support policies would probably not be sufficient. Different strategies can be followed in order to increase the changes of achieving the EU targets. These strategies have been translated into scenarios for the ADMIRE REBUS model.

- Intensification of present policies: levels of support are increased to reach the targets in 2010. This is further elaborated in Section 6.2.
- Instead of increasing the level of support, governments could attempt to facilitate the instalment of new capacity. As described in Chapter 4 in this report, not only financial matters determine the deployment of renewable electricity, but lead times and risk have a great influence as well. By introducing more efficient administrative procedures and a higher success rate, targets can be more easily met. This scenario is described in Section 6.3.
- Introduction of international trade in a completely harmonised market combined with mandatory targets for 2010. In Section 6.4 a scenario is described in which the chances of achieving the target are maximised, by assuming that trade is facilitated in a TGC market from 2004 on.

- Stimulating Demand Side Management: with less consumption of electricity it will be easier to reach the targets. Section 6.5 describes a scenario in which electricity consumption increases to a 10% lower level in 2010 than in the reference projections, thereby allowing more countries to reach their targets under continuation of present policies.

6.2 Policy intensification

Would the maintenance of the support schemes together with an increase in support levels allow Member States to achieve their targets? How much additional public money would these countries have to spend in order to reach their targets? For those countries that would be able to reach their targets by making additional financial efforts (i.e. policy intensification), what would be the technologies most likely to allow them to reach the targets? We will try to answer these questions in this section with the help of the simulations performed with the ADMIRE-REBUS model.

Assumptions
This scenario assumes that countries increase their support levels in the most efficient way. For this purpose, the target has been translated into an 'artificial quota obligation' to be met domestically in 2010. The resulting demand section has been given a bid price of 15 ct/kWh in the period 2004-2010, which can be interpreted as the penalty associated with not meeting the quota. This way, the model allocates supply sections in increasing order of costs, implying that the cheapest technologies and bands are used to achieve the target. The required green price (RGP, see Section 2.1) of the marginal option - the most expensive supply option installed to achieve the target - gives a conservative estimate of the support level necessary to achieve the target.

This approach does not take into account any reasons that countries may have to introduce technology specific policies, such as feed-in tariffs. Therefore, it is to be expected that wind onshore and biomass are the main technologies employed, while technologies such as wind offshore and photovoltaics do not see much growth.

Effectiveness
In the intensification scenario, most countries are able to achieve their targets under this scenario. Only a few countries would still not reach the targets, even if a very high increase in support is provided to RES-E. These are Belgium (realised supply in 2010 in the intensification scenario is 70% of target), Luxembourg (55%), Portugal (76%) and Italy (97%), although Italy is very close to its target.

For the three countries still not reaching their target, after increasing their support levels to maximally 15 ct/kWh, there must be bottlenecks at the supply side, i.e. in the amount of potential available at a certain point in time. The reasons for this differ by country. For Luxembourg, it is a matter of lack of potential, due to the small size of the country. Belgium has long lead times and potentials at high costs. For Portugal, the target can be regarded as quite ambitious in absolute terms, because a 46% growth in electricity demand is foreseen from 2000-2010 (European Commission, 1999). This means that although the relative increase in share of renewable electricity from 38.5% in 1997 to 39% in 2010 is rather small, it requires a considerable effort in absolute terms. Another factor is the fact that investors in Portugal only know the level of feed-in tariff they will receive for the present year, which increases their risk and therefore they require a higher return on equity.

Support levels under policy intensification
As already mentioned, in the intensification scenario an increase in support levels beyond the increase expected in the Continuation of Present Policies scenario leads to an increase in deployment levels as well. That allows most countries to reach the RES-E Directive targets domestically, with their own policies. This effectiveness comes at a cost. Therefore, even if effec-

tiveness is attained, cost-effectiveness will be relatively low. The projected additional production costs for achieving 659 TWh renewable electricity production in the EU in 2010 are 10.5 bln €. The total additional expenditures (government subsidies and end-user expenditures) amount to 28.8 bln € in 2010. These expenditures are very high, because they are based on the equilibrium prices found for the (artificially constructed) quota obligations in a number of countries, including a number of countries where the penalty for incompliance is paid, see Table 6.1.

For the eight countries that could achieve their target by intensifying their support policies, what would be the minimal level of support? Table 6.1 gives the required green price of the marginal option required to achieve the target in the countries intensifying their policies. As explained before, this price can be regarded a lower bound to the level of support required for achieving the EU targets domestically in the most efficient way, not stimulating the deployment of some of the more expensive technologies. This is illustrated by the Irish case. In the intensification scenario, the Irish target for 50 MW offshore wind capacity in 2005 is not achieved. Rather, a large amount of (cheaper) onshore wind is installed. This is a direct consequence of the way the scenario has been constructed, using artificial (domestic) quota obligations from 2004 on.

Table 6.1 *Minimal support levels required for achieving the targets under policy intensification [ct/kWh]*

	2010
Belgium*	14.9
Denmark	4.6
Finland	2.2
France	4.0
Germany	5.9
Greece	5.3
Ireland	1.5
Italy*	14.9
Luxembourg*	14.9
Portugal*	14.9
Spain	9.4
Sweden	2.8

Note: countries marked with * do not achieve their target; the support level indicated is the penalty paid for non-compliance.

Summing up, quite large increases in support levels and government and end-user expenditures are experienced by some countries in the policy intensification scenario compared to the Continuation of Present Policies scenario during the 2000-2010 period.

6.3 Removing implementation barriers

There are other ways than financial support that can be used to foster renewable energy investments. In Chapter 4, we have highlighted the importance of political risks for investors. Part of these risks deal with the conditions and durability of the support schemes and part deal with the political authorisations that are necessary to be able to build the project. Administrative barriers to investments in renewable energies are one factor with which it is also possible to play. Administrative barriers are of two types: delays and non-granting of permits. Removing these barriers implies the reduction of lead times and the augmentation of the success rates, which is the diminution of the number of projects that are rejected for one that is granted a permit.

Model simulations with all lead times divided by two do not show significant results in terms of realised supply. This means that an action on lead times alone is not sufficient to boost renewable energy investments. What has more importance is in fact the number of projects an investor has to present in front of administrations so as to obtain at least one permit, hence one approved project proposal. Delays are less important than rejected applications. A reduction of the risk regarding authorisations has a major effect on the costs to achieve the targets.

Therefore, a scenario has been constructed in which lead times are halved, application approval rates increase with 50%, and the capacity of the industry to increase their production levels from year to year increases with 20%[39]. All these factors contribute to a larger amount of the realistic potential to be available on the market in a certain year.

Indeed, lowering lead times and failure rates in ADMIRE REBUS model leads to more renewable electricity production in the Continuation of Present Policies scenario as illustrated in Figure 6.5. For the EU-15, the compliance rate increases from 82% to 89%. Notable is that three additional countries - Belgium, Denmark and Greece - achieve their target in 2010, apart from Austria, the Netherlands and the UK. For one of these countries, Belgium, the policy intensification scenario had already shown that increasing the support level is not effective in achieving the target. Moreover, many other countries also reduce the gap between realisation and target in 2010, although it is clear that administrative problems are not equally a barrier for all countries.

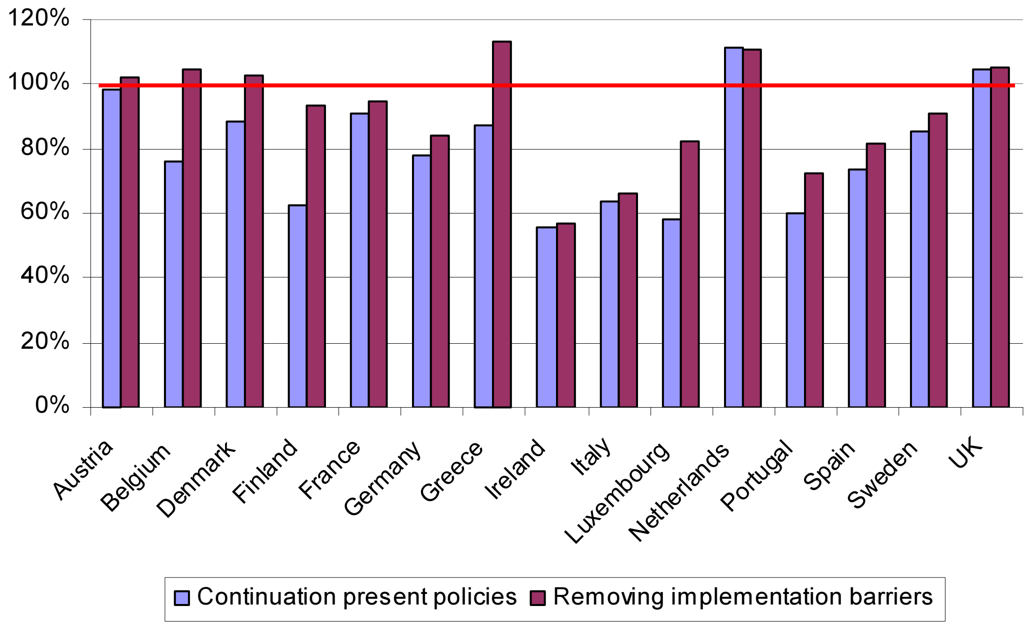


Figure 6.5 *Relative compliance under the scenario 'removing implementation barriers' in 2010 compared with the continuation of present policies scenario*

The removal of implementation barriers saves costs; in this scenario, projected additional production costs amount to 5.1 bln €, corresponding to a production of 588 TWh in the EU. The total additional expenditures amount 8.7 bln €.

6.4 Introduction of quota obligations and international trade

As an ideal case, the scenario described in this section assumes the introduction of trade in 2004, combined with quota obligations with stringent compliance enforcement enabling the targets to be achieved in 2010. This scenario provides the most optimistic vision of what can be achieved, because it takes the targets as starting points. Of course, the very abrupt transition in 2004 from current policies to an EU wide TGC system with trade is hardly likely, but in this scenario all countries achieve their target without problems. The projected additional production

[39] A definition of these parameters is given in (Daniels et al., 2003)

costs in the EU-15 are 10 bln €, and the projected total additional expenditures, based on a TGC price of 6.1 ct/kWh in 2010, are 24.4 bln €. In Chapter 7 more details on the technology mix and trade flows in this scenario are presented. Section 6.6 elaborates further on the costs of this scenario.

6.5 Stimulating demand-side management

Until now, all analyses have focused on ways to achieve the targets by stimulating more renewables deployment in the EU Member States. Although there are many benefits from an increased share of renewable electricity, such as reduction of CO_2 emissions, security of supply, environment, and possibly employment, the costs are also significant. Given the fact that the targets are expressed as a share of electricity consumption, measures to reduce electricity demand could also be considered.

As an example, Figure 6.6 shows that when all countries would have a 10% lower electricity demand than projected in (European Commission, 1999) overall compliance would increase to 91% without additional costs. Likewise, achieving these 10% lower targets on the basis of trade in an international market would cost 14.4 bln € instead of 24.4 bln € (total additional government and end-user expenditures). This cost reduction is much larger than the 10% demand reduction. This is amongst others due to a more moderate development of the TGC price. Projected additional production costs would amount to 6.5 bln €, corresponding to 598 TWh installed.

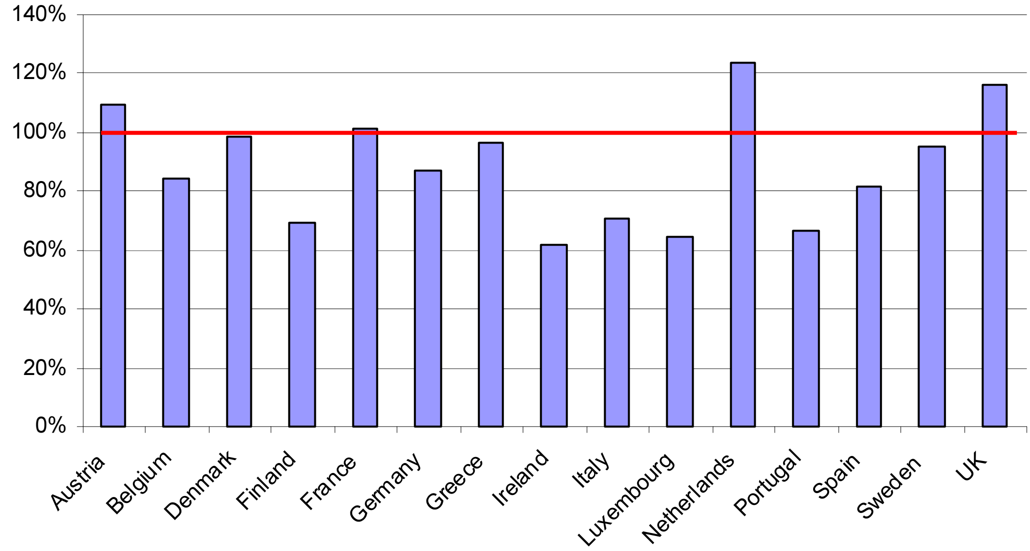


Figure 6.6 *Relative compliance under the Continuation of Present Policies scenario with gross electricity demand in 2010 10% lower than in the reference projection*

6.6 Cost of achieving targets

It is interesting to compare the two scenarios where the targets are achieved under the reference electricity demand projections. In Figure 6.7 costs and production levels for the EU-15 are presented for the Trade & Harmonisation 2004 scenario to the Policy intensification scenario. Both scenarios increase efforts for achieving the targets from 2004 on, but the main difference is the absence of trade in the Policy intensification scenario[40]. In other words, the Policy Intensifica-

[40] With the exception of The Netherlands, that is assumed to continue its current policy, partly relying on imports. However, in this scenario the other Member States first meet their own targets by domestic production before considering export to The Netherlands.

tion scenario shows the effort countries have to make to achieve their target domestically, while the Trade & Harmonisation 2004 shows the benefits of international trade.

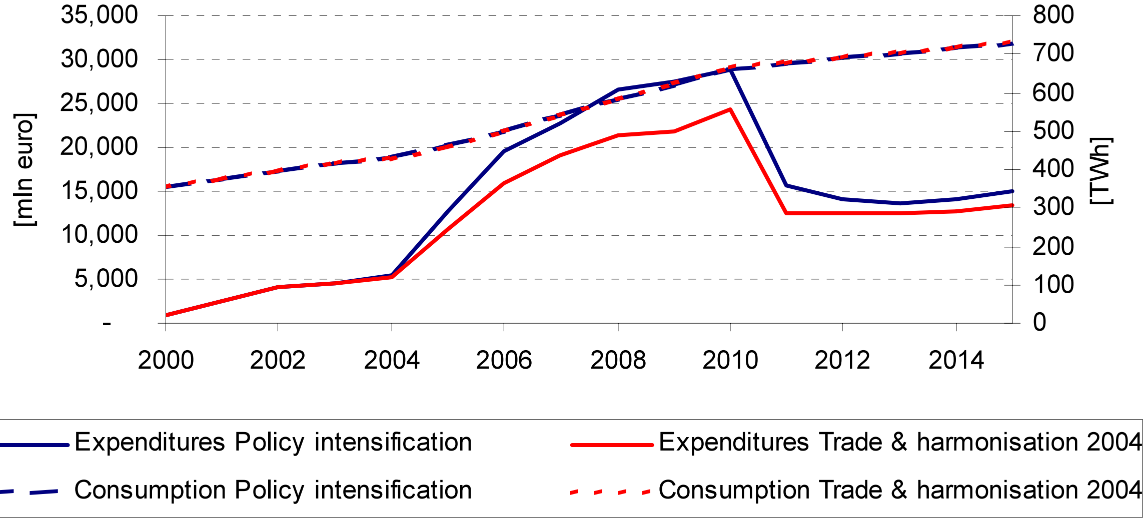


Figure 6.7 *Comparing production and total expenditures in the Trade scenario to the Policy Intensification scenario*

A number of observations can be made based on Figure 6.7. First, it clearly shows that the total expenditures related to the achievement of the EU Renewables Directive targets are lower in a situation of trade and (quota-based) harmonisation[41], when renewable electricity generation is done at the most efficient locations. Secondly, it shows that the costs are directly related to the TGC prices established on the market, which in both scenarios increase during the period until 2010, when the targets appear to be quite ambitious. After 2010, the ambition level no longer increases, and the price of the certificates is expected to stabilise at a lower level, thereby also reducing total expenditures. In Section 7.4 more information is given on market prices.

Table 6.2 gives an overview of the costs and expenditures presented in this chapter for the different scenarios. The expenditures appear to be particularly sensitive to two inputs, the level of the electricity demand directly affecting the level of the targets, and the level of electricity prices. Therefore several variants on the Trade & harmonisation scenario in 2004 have been calculated and are listed here as well.

As explained in Section 2.3, the additional production costs are the summation of the 'required green prices', a measure for the revenues needed by a producer in order to make his investment viable, including a risk premium, but excluding any profits. Therefore these costs are a lower bound to the expenses necessary to induce the renewables deployment necessary to achieve the target.

[41] A harmonisation of feed-in tariffs in the EU is also possible. In combination with international trade this could also lead to achieving the targets in a more efficient way compared to no trade at all. However, the cost effectiveness would depend on the levels chosen for the feed-in tariffs.

Table 6.2 *Overview of costs in 2010 for different scenarios*

Scenario	Total consumption [TWh]	Compliance EU-15 [%]	Total additional production costs[42] [bln €]	Total government & end-user expenditures[43] [bln €]
Continuation present policies	543	82	4.7	9.4
Continuation present policies & removing implementation barriers	588	89	5.1	8.7
Policy intensification	659	99	10.5	28.8
Trade & harmonisation 2004	663	100	10.0	24.4
Variants on Trade & harmonisation 2004:				
1. Demand Side Management: 10% less electricity consumption and lower targets	599	100	6.5	14.4
2. Higher commodity prices (EU average 4.0 ct/kWh instead of 3.0 ct/kWh)	663	100	8.6	20.7
3. Combination of variants 1 and 2 - higher commodity prices give an incentive for Demand Side Management	599	100	5.4	11.4

Summarising, in 2010, the total expenditures related to achieving the indicative targets range on an annual basis from 11 to 29 bln €. The upper value relates to a cost-effective intensification of current support systems to meet national RES-E targets, along with modestly increasing prices on electricity wholesale markets, due to a continuation of existing overcapacity in the power sector and a negligible carbon premium. The lower value is based on a scenario of a completely harmonised support system along with substantial price rises on the electricity wholesale markets (sharp reduction in generating overcapacity and a significant carbon premium). The transition from meeting targets with intensification of current support systems to Union-wide harmonisation of RES-E support is projected to reduce total additional government and end-user expenditures in the EU-15 by at least 4.4 bln € in the year 2010.

[42] Additional production costs are calculated based on the 'required green prices' – the revenues incurred by producers additional to the commodity price of electricity – and therefore exclude the producers' surplus.

[43] Total expenditures are a sum of government expenditures (investment and production subsidies) and for those countries using a market based system, the certificate prices multiplied by production volumes

7. ANALYSIS OF THE DEVELOPMENT OF A EUROPEAN MARKET FOR RENEWABLE ELECTRICITY

7.1 Introduction

This chapter provides information on technology implementation and market prices for different renewable technologies. The projections are based on a comparison of a number of scenarios, with the purpose to indicate ranges for likely developments. The scenarios that have been chosen are distinct in several aspects, in order to describe a broad playing field. As illustrated in Figure 7.1, the main scenario dimensions are the ambition level - when is 22% renewable electricity in the European Union achieved? - and the extent to which the countries cooperate in achieving this target. In Chapter 5, the background to these scenarios is given.

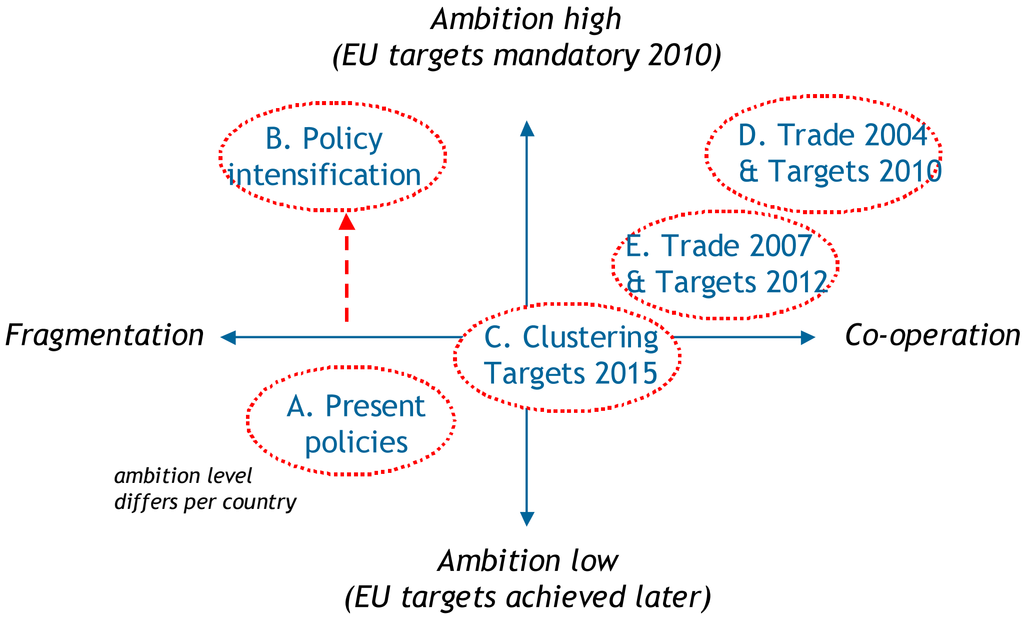


Figure 7.1 *Overview of the scenarios presented in this chapter*

The following scenarios have been used.

A. *Continuation Present Policies*; the reference also used in the previous chapter. Note that for the years a bit further ahead, the likeliness of this scenario quickly decreases, because it is a simple extrapolation of the situation early 2003. Given the fact that most countries do not reach their targets, it could be regarded the most pessimistic scenario of the ones considered here.

B. *Policy Intensification*, as described in the previous chapter, leads to an achievement of targets at relatively high costs in 2010. We assume that in 2012 harmonisation takes place; the countries are already well on track with regard to the targets.

C. A more realistic scenario could be *Clustered Europe* as described in Chapter 5.2.2. A gradual process of harmonisation and trade, in which targets are reached in 2015. Note that the outcomes directly depend on the assumptions on which countries enter the bubble and which do not, and that continuation of present policies (mainly feed-in tariffs) is assumed for those countries that do not participate in the international TGC market at all.

D. The extreme reference point also used in the previous chapter: introduction of trade and quota-based harmonisation in 2004; targets reached in 2010. This could be regarded the most optimistic scenario of the ones described here, and is called *Trade & Harmonisation 2004-2010.*

E. Finally, *Trade & Harmonisation 2007-2012***,** a variant where trade and harmonisation are introduced EU-wide in 2007 and targets are mandatory in 2012.

7.2 Technology prospects

The model results indicate which technologies will be deployed under the different scenarios. With a continuation of present policies (Scenario A) biomass will play an important role (Figure 7.2). However, wind power onshore will still be the main single technology, besides large hydropower. Large hydropower more or less keeps its existing capacity from 1997 - hardly any new capacity is deployed.

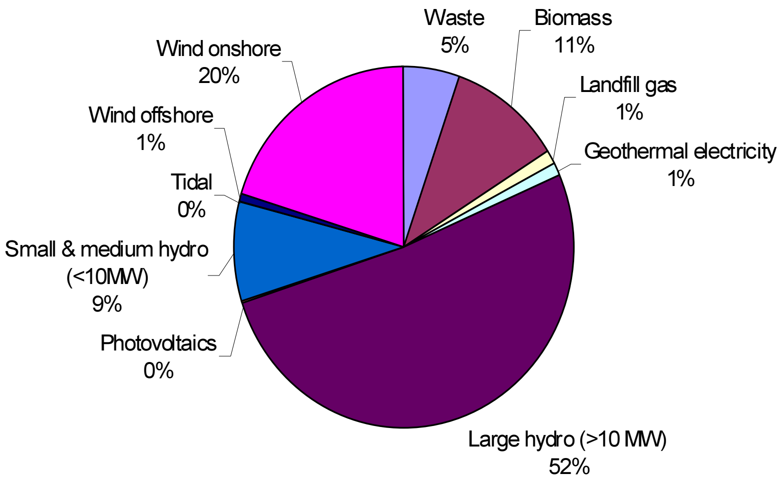


Figure 7.2 *EU Technology mix in Scenario Continuation of Present Policies in 2010*

Photovoltaic (PV) is poised to make a negligible contribution in 2010. More surprisingly, wind offshore only plays a minor role in scenario Continuation of Present Policies with 1% of the RES-E production in 2010.

All other scenarios considered have a higher ambition level, and lead to a higher deployment of RES-E in general, as shown in Figure 7.3. Certain technologies will benefit more than others from the higher demand and higher market price. Those that seem to gain most are on- and offshore wind, biomass technologies in general and to a lesser extent geothermal electricity.

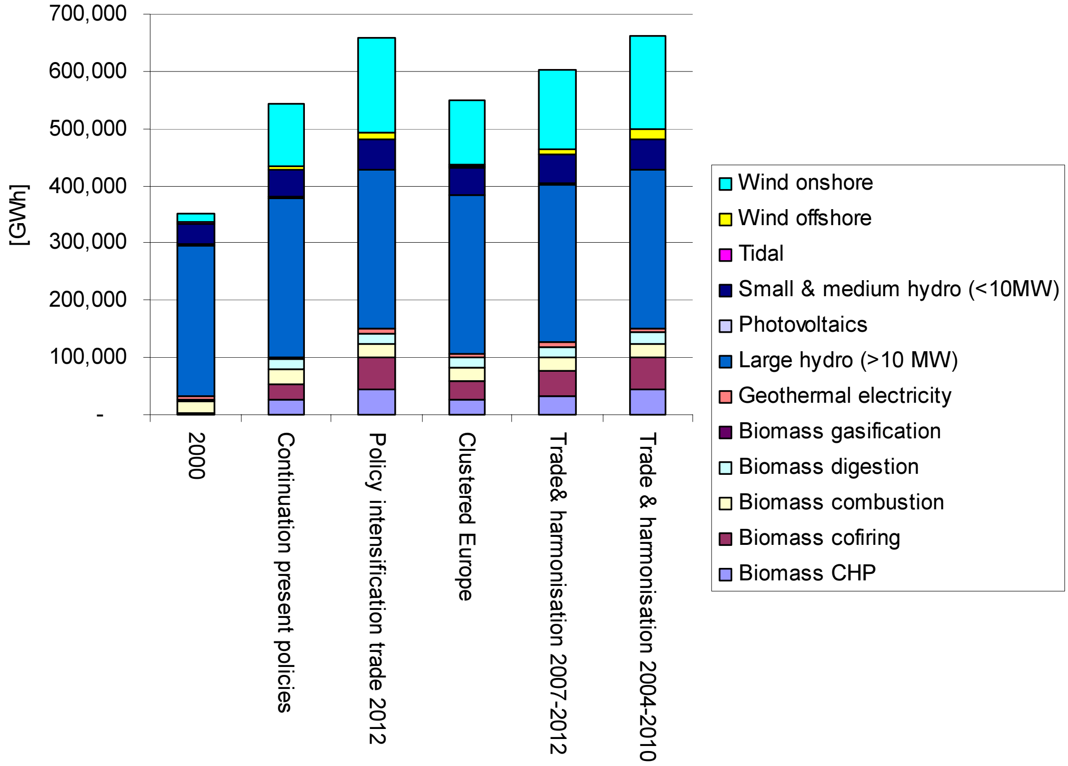


Figure 7.3 *EU Technology mix in 2010 compared for different scenarios*

7.2.1 Offshore wind

In particular offshore wind power is very dependent on the policy ambition level. As can be seen from Figure 7.4, there will be a modest yet declining growth until 2010 with continuation of present policies, but the EWEA target of 10 GW in 2010 will not be met according to these projections. Development will mainly take place in Denmark, The Netherlands and the United Kingdom. Specific offshore wind policy support levels across the EU are too low compared to the expected future investment costs of offshore wind energy to build profitable projects. If offshore wind can only benefit from generic policy support, competition with other renewable sources reduces its possibilities. Remarkably, with the current German offshore wind support scheme there will be no market opportunities in Germany at all (see also Section 8.2), despite the large number of proposed projects.

However, if the market is based on international trade in order to achieve the EU renewables target, offshore wind energy will benefit from a higher level of the TGC price. Nevertheless, penetration starts more slowly in 2005 because of competition with other renewables. In these scenarios, Germany and Denmark will play an important role. The expectation, based on Scenario D and E for the years after 2010, is that the market opportunities for offshore wind energy improve considerably due to ongoing cost reductions and expected learning effects.

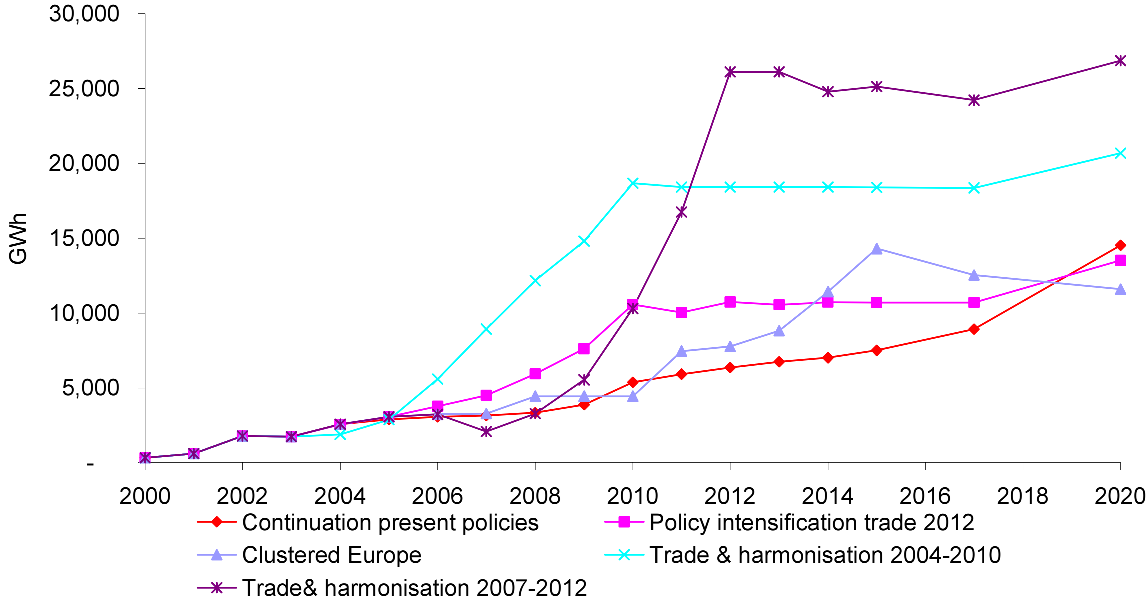


Figure 7.4 *Wind offshore development*

7.2.2 Onshore wind

Achievement of EU targets will to a large extent rely on deployment of onshore wind power, for which a considerable growth is expected under all scenarios. Under Continuation of Present Policies, a growth from 17 TWh in 2000 to 109 TWh in 2010 is foreseen, and a continued but declining growth beyond 2010. Scenarios B and D (see Figure 7.5) project 164 TWh in 2010.

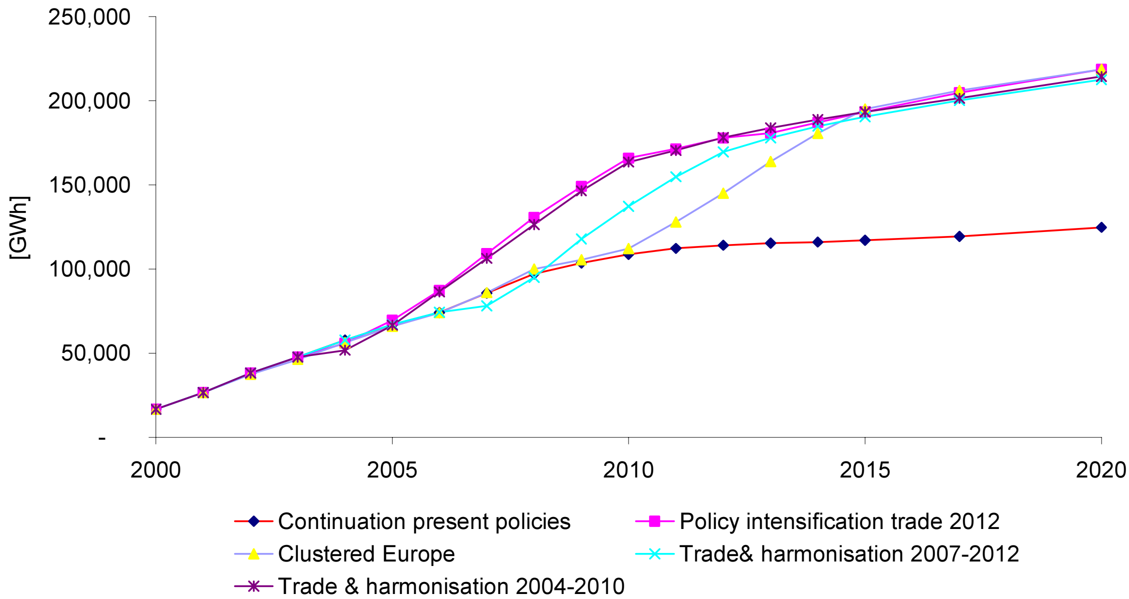


Figure 7.5 *Wind onshore development*

Main countries, as illustrated in Figure 7.6, are the UK, Germany, France and Spain. Remarkable is that in the more ambitious scenarios, the production in Sweden increases from 0.2 TWh under current policies to 13.7 TWh in Scenario D. Apparently, the exploitation of the significant onshore wind resource in Sweden requires additional support policies.

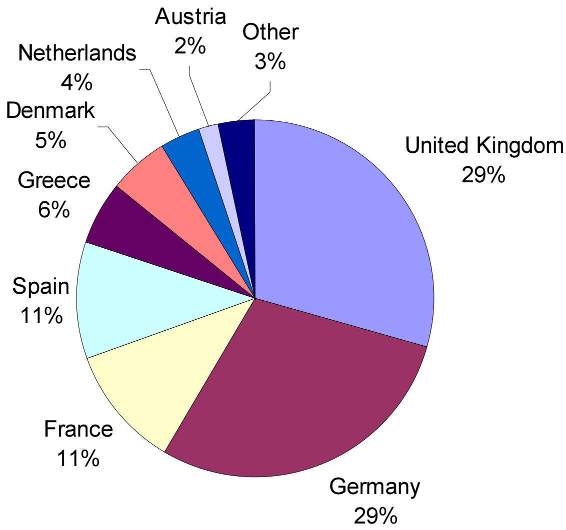


Figure 7.6 *Contribution of EU countries to wind onshore deployment in 2010, Scenario Continuation of Present Policies*

7.2.3 Biomass

The use of biomass will increase in general if policy ambition level increases. A trend is that biomass-fired CHPs and co-fired facilities will benefit more from the introduction of a TGC system than other biomass technologies, such as gasification, anaerobic digestion (biogas) and ordinary biomass combustion. The significant rise in biomass CHPs and biomass co-firing, when establishing a common European TGC market compared to continuation of the current policies is illustrated in the figures below.

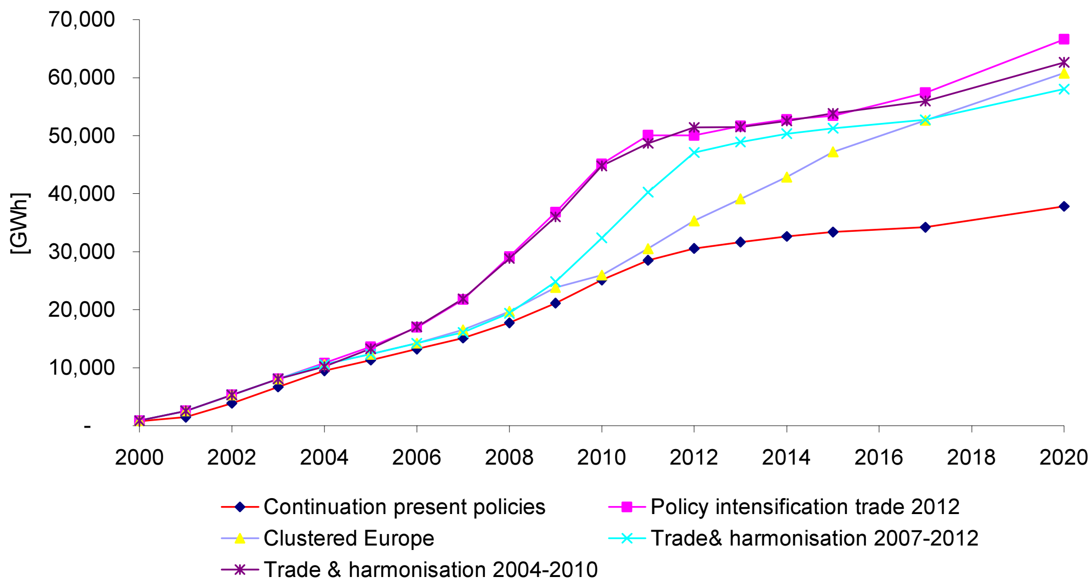


Figure 7.7 *Biomass CHP development*

The reason for the strong projected increase in use of these technologies is that they are more competitive in comparison with other biomass technologies and renewable technologies in general. For co-firing, an additional reason is that this technology is hardly supported under specific policies, such as feed-in tariffs, but within a generic policy such as a TGC system, it is one of the cheapest options.

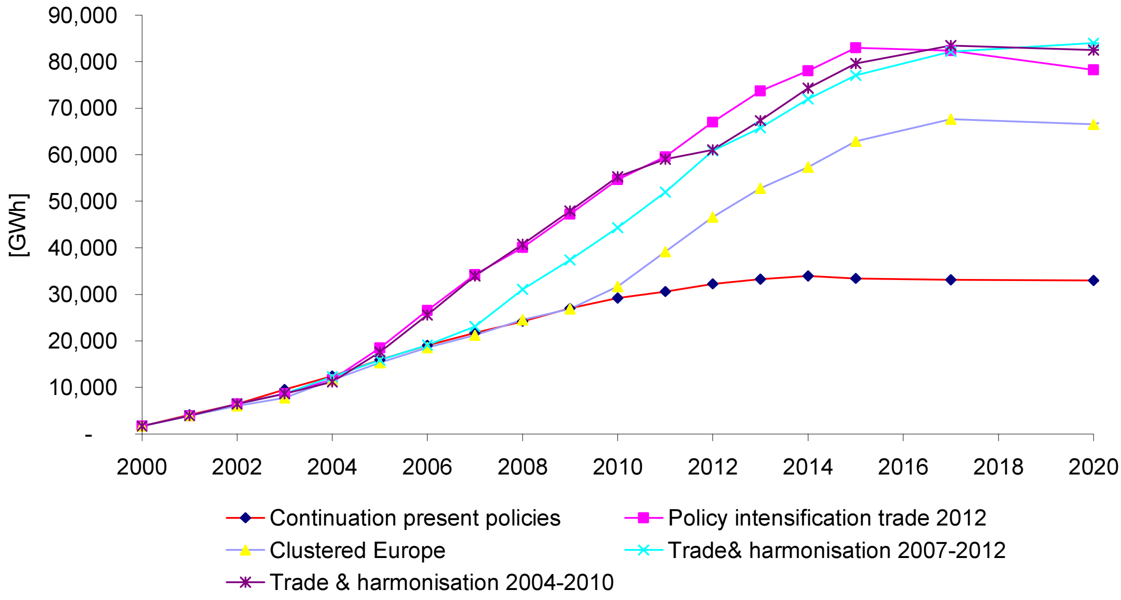


Figure 7.8 *Biomass co-firing development*

With respect to the deployment of different biomass resources, as illustrated in Figure 7.9, electricity from agricultural residues shows a significant growth from 4.1 TWh in 2000 to 26 TWh in 2010 and a continued growth beyond 2010. Forestry residues also play an important role and grow from 3.1 TWh in 2000 to 28 TWh in 2010. Main countries are Austria, France, Germany, Spain, Finland, Sweden, Italy, and the UK.

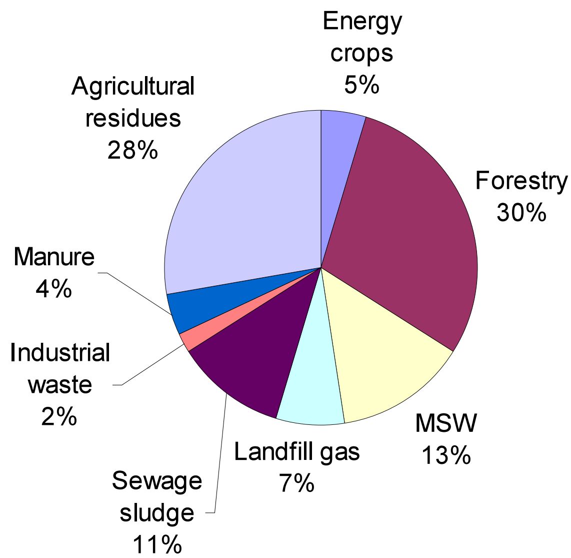


Figure 7.9 *Biomass resource mix in 2010 under continuation of present policies*

The potential for use of biomass in electricity generation is very large and in these scenarios only the biomass potentials of the Member States themselves are taken into account. Taking into account that the biomass fuel can be traded between the Member States, potentials can be moved from one area to another. Furthermore, interactions with the Renewable Fuels Directive have not been taken into consideration here - see Section 7.5.2.

7.2.4 Geothermal

Though geothermal electricity will be a minor contributor to achieve the overall target of 2010 the influence from imposing a TGC system in combination with mandatory targets is significant, which means that there are unexploited potentials at competitive prices in several countries. Under a TGC system in combination with mandatory targets the EU White Paper target of 1000 MW can be achieved with installations in Italy, Portugal and Greece. Hence the introduction of generic policies may act as removal of barriers for certain developing technologies, such as geothermal electricity technology. In the continuation of current policies scenario it seems that the exploitation of geothermal energy for electricity generation will stagnate, which could harm the development of this technology in the long run.

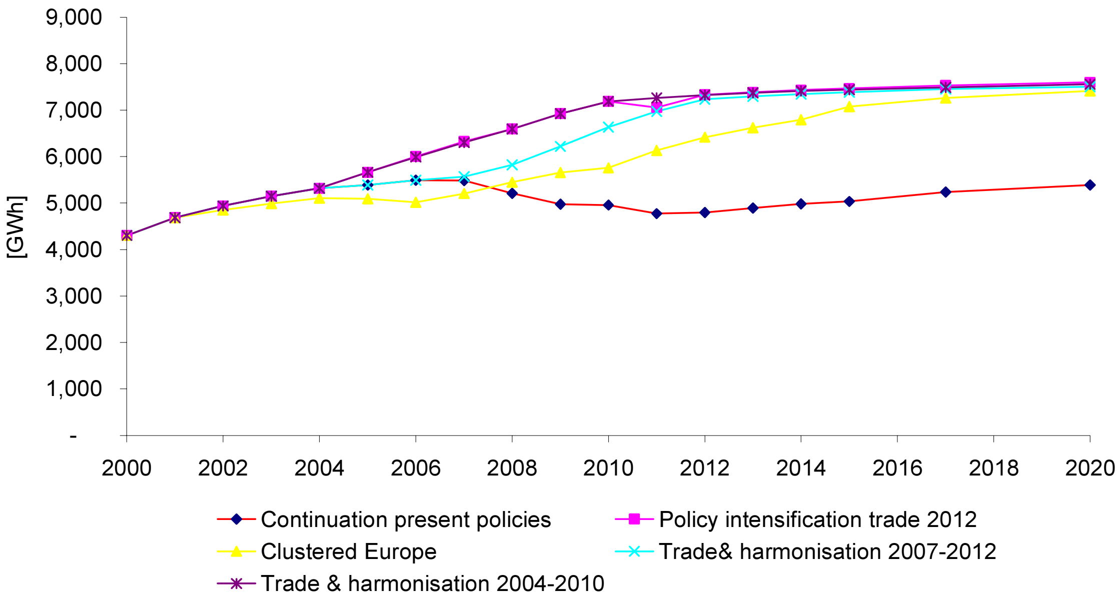


Figure 7.10 *Geothermal development*

7.2.5 Photovoltaic

The prospects for PV are uncertain - it is the only technology that shows more growth under continuation of present policies than in a scenario assuming the introduction of a TGC market. Obviously, this technology needs specific policies with relatively high levels of feed-in tariffs (or technology-specific quota). Under continuation of present policies, PV will mainly be installed in Spain, Portugal, Germany, and Austria. Growth is also expected in France.

7.3 Promising markets for renewables

The opening of the market for electricity from renewable resources will have the consequence that some countries will be importers of RES-E while others will be exporters. In this respect, the main question is: which countries will open their markets and when? This completely determines the trade flows that could emerge. In the trade scenarios involving all EU countries, the main importers will in 2010 be Spain, Portugal and Italy, while the largest exporters will be Denmark, Germany, UK and Ireland. Beyond 2010, Sweden also becomes and exporting country, which is due to the growth of onshore wind.

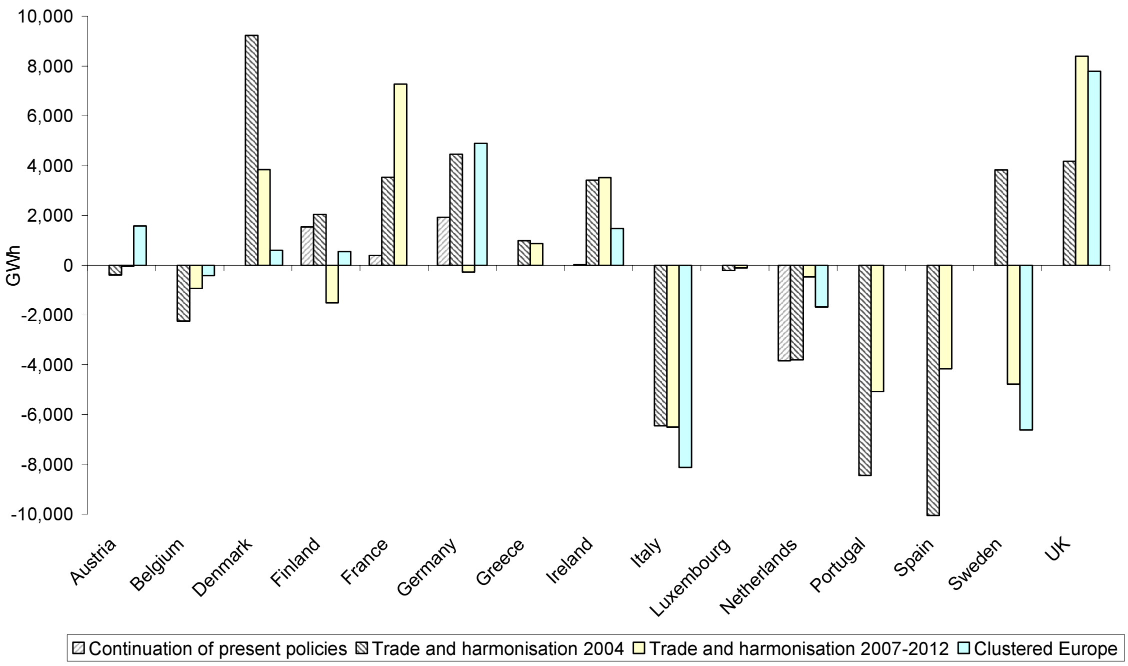


Figure 7.11 *Net trade flows in 2010 in different scenarios (export is positive)*

Figure 7.12 shows the amount of renewable electricity traded in relation to domestic consumption in 2015.

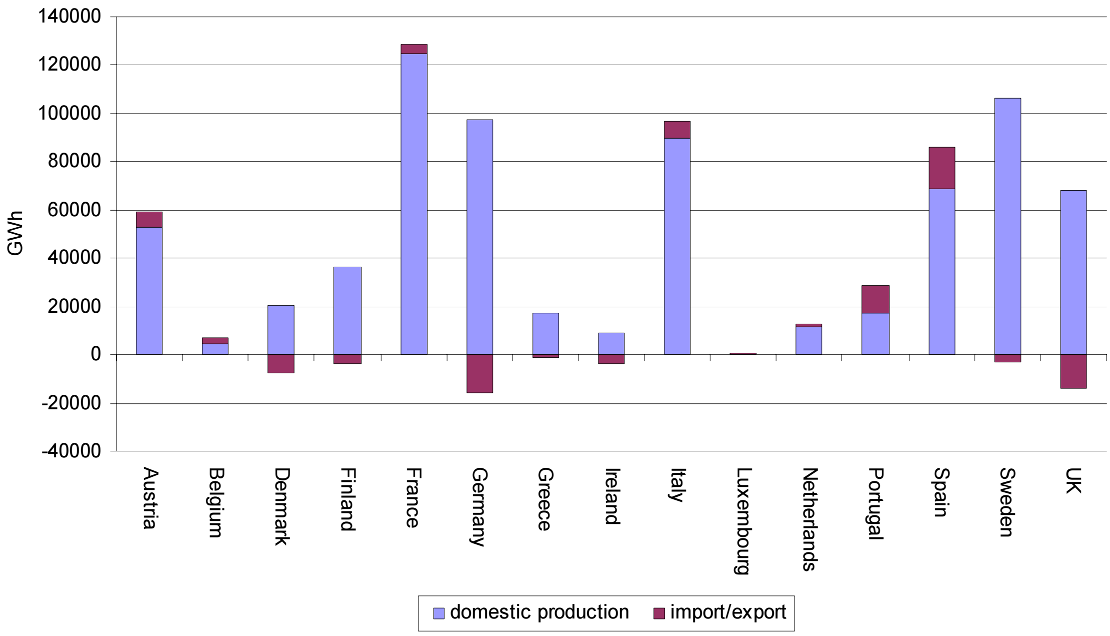


Figure 7.12 *Trade related to domestic production in 2015, Scenario Trade & harmonisation 2004-2010 (negative is export)*

7.4 Long term renewable electricity price expectations

In this section, the assumption is made that in the long run, an EU-wide TGC system is in place conform Scenarios D and E[44]. In that case, the price for renewable electricity will be set by the market and vary over time, since the supply and demand ratio is not constant. The projected development of the TGC prices is illustrated below for different scenarios.

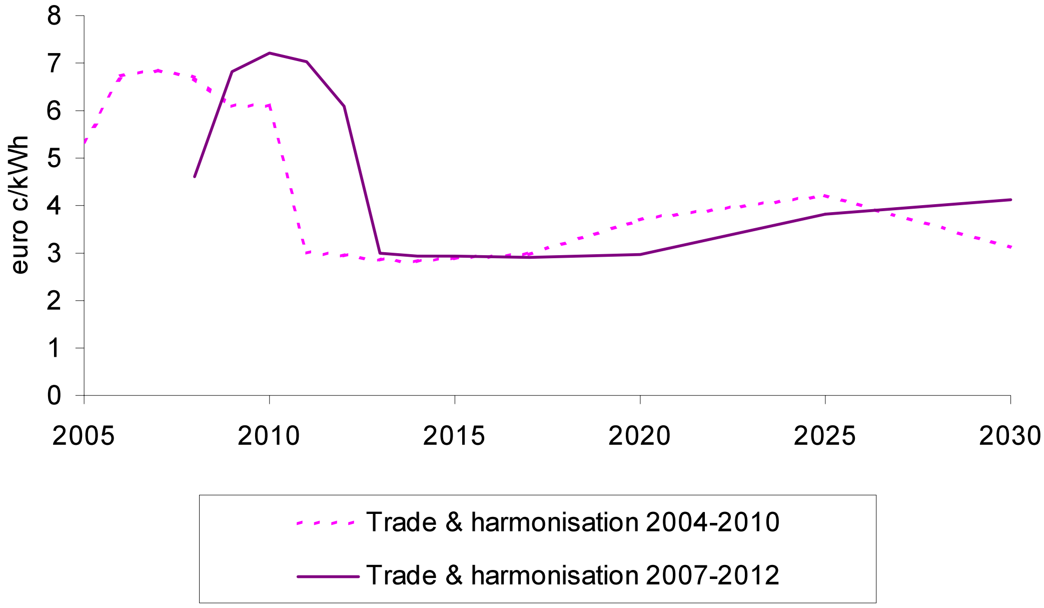


Figure 7.13 *Development of the TGC price in two scenarios*

In addition to an average electricity price at 3 ct/kWh, the price of certificates in the TGC system is expected to rise rapidly until 2006 as a consequence of the sudden boom in demand for RES-E with the introduction of the system in 2004. The certificate price lies on a high level of over 6 ct/kWh until 2010 due to the continuous demand increase. In the period until the targets are met, the price is much higher than afterwards. After meeting the target in 2010 the price of the certificates is expected to stabilise just below 3 ct/kWh, but this is only if no new obligations are laid on consumption, as continuous tightening of obligations will pull the prices on the certificates to fairly high levels[45]. Beyond 2020, the price slightly increases again due to replacement of the stock of which a large part was installed in 2005-2010.

One of the most important factors determining the development of the TGC price is the level of demand, either caused by policy ambition level or by the underlying electricity demand. For example, a 15% lower electricity demand in the EU decreases the price level by on average 1 ct/kWh. Furthermore, it should be noted that investment support is assumed to be continued under a harmonised framework. If it is abolished, the TGC price increases with up to 0.5 ct/kWh.

Finally, it should be noted that the projected development of the TGC price is very sensitive to the way the transition period has been modelled. In the current analysis, the assumption has been made that in the year in which trade is introduced, the demand does not increase. In other words, the quota does not become binding until the next year, and this approach is chosen to reflect that the market needs some time to adapt to the changing institutional structures. This ex-

[44] Trade & Harmonisation 2004-2010 and Trade & Harmonisation 2007-2012 respectively.

[45] The targets are assumed not to increase beyond 2010 in relative terms. In absolute terms, they will increase with the expected growth of the electricity demand.

plains the gradual increase shown in the TGC price. However, should the transition period be modelled in a stricter way, the development of the TGC price would also show another pattern. In Figure 7.14 the two projections are shown side by side for comparison. Apparently, the development of the TGC price in the period until the targets are met is subject to a large uncertainty, as also confirmed by the sensitivity analysis. In the period beyond 2010, the price is much more stable.

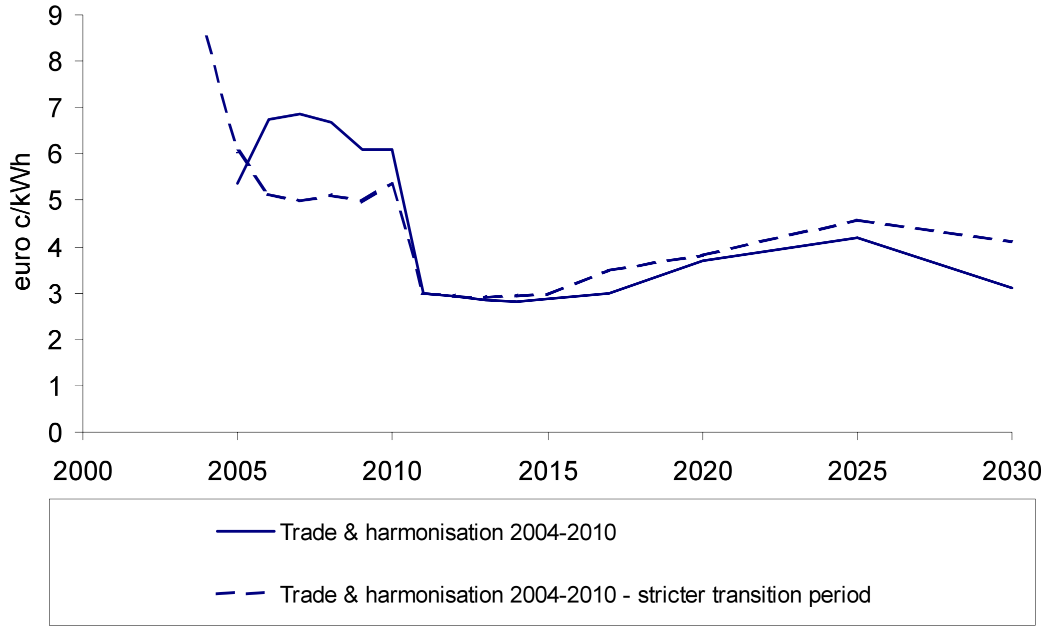


Figure 7.14 *Development of the TGC price under different assumptions on the transition period*

7.5 External developments

This study has its focus on the expectations regarding the market for renewable electricity in the European Union. However, several exogenous developments could have a direct influence on the prospects for renewable electricity in Europe. This section provides illustrations of the significance of emissions trading, the development of a biofuel market, and the enlargement of the EU with 10 additional Member States.

7.5.1 Emissions trading

Besides the RES-E targets the EU has other environmental targets. One of these relates to greenhouse gas reduction. The EU emissions trading system, to be in place as from 2005, will include the power-generating sector. A larger deployment of RES-E will replace a certain amount of thermal power production. This will make compliance for affected parties achievable at somewhat lesser efforts. Likewise, a restriction at the thermal power producers will increase the RES-E producers' competitiveness.

In July 2003, agreement was reached on the text of the EU's new greenhouse gas emissions trading directive, which is expected to enter into force in the last quarter of 2003. When in 2005 an emission permit market is launched, a rising permit price will increase the total thermal supply cost and thereby imply a higher power price. This will be an advantage for the RES-E supply if these sell power at market price, e.g. in a TGC system, causing the RES-E target to be met at a lower TGC price. Indicative calculations using the ADMIRE REBUS model and the high commodity price scenario as described in Section 2.2.2, indicate that total expenditures for achieving the target in 2010 would amount 20.7 bln € instead of 24.4 bln € (using the Harmonised

Europe scenario where trade starts in 2004). The TGC price in 2010 would be 5.2 ct/kWh instead of 6.1 ct/kWh.

However, it is not sure that all RES-E producers benefit from emission trade. Co-fired biomass plants have a double role. On one hand, the smaller amount of thermal fuel, compared to the absence of co-firing, makes them more competitive at the thermal power market. On the other hand, the use of thermal fuels makes the production more costly, which is a disadvantage at the RES-E market.

7.5.2 Development of a biofuel market

Not only the European electricity sector is affected by climate and resource protection policies. The green paper *towards a European strategy for the security of energy supply* also addresses the transport sector. It proposes to substitute 20% of the fossil fuel use in the transport sector by alternative fuels like biofuels or hydrogen.

Against this background the EU has adopted a directive *on the promotion of the use of biofuels or other renewable fuels for transport*.[46] The directive - which has to be transposed into Member States legislation by 31 December 2003 - commits the Member States to assure a minimum share of biofuels in their domestic fuel markets based on national indicative targets. Furthermore the directive defines reference values for these targets. By the end of 2005 biofuels should have a market share of at least 2% of petrol and diesel supply for transport purposes. The target increases up to 5.75% by the end of the year 2010 which would correspond to a calorific value of roughly 17.5 Mtoe.[47]

The desired development of the biofuel market might have an effect on the availability of biomass resources in the electricity sector. The additional use of several types of resources in the transport sector (e.g. rapeseed for the production of biodiesel and wheat, barley, maize or sugar beets for the production of bioethanol) limits the facility to utilise the biomass potential in the electricity sector. The additional scarcity may lead to an increase in market prices for these resources. Thus, in a harmonised EU-wide market for renewable electricity, economically attractive biomass options would be crowded out and, if a RES-E target has to be met, are replaced with more expensive options. As a consequence the developments in the biofuel markets can have a direct impact on the value of renewable electricity respectively the TGC price.

As a first illustration of what the impact could be, we simulated the increased use of biofuels by lowering the potential of biomass feedstock available for the electricity sector (see Table 7.1). The effect on the TGC price can be observed in Figure 7.15. The figure shows the development of the TGC price in scenario Trade & Harmonisation 2007-2012 with and without potential scarcity of biomass resources. The influence on the TGC price is non-negligible. In 2010 - when the biofuels directive target has to be achieved - the TGC price is about 0.75 ct/kWh higher than in the situation where the initial biomass potential is available[48]. In year 2012 - when the RES-E target is met in this scenario - nearly the same difference can be observed. In the long run the difference diminishes.

These simulation results are based on rather rough approximations of the development in biomass resource markets caused by the biofuels directive, and do not take into account price in-

[46] Directive 2003/30/EC of the European Parliament and of the Council on the promotion of the use of biofuels or other renewable fuels for transport of 8 May 2003.

[47] Under the assumption of a continuous growth of the transport sector of 2% per year.

[48] Note that in this first illustration, no price increase for biomass feedstock has been assumed. The reduction in available potential is filled in with other technologies, notably wind. However, simulating a price increase instead of reducing the available potential might give different results, because biomass based electricity might still be competitive with other renewable electricity generation, even with higher costs. Still, an upward effect on the TGC price might be the result.

creases in biomass feedstock due to scarcity of resources. A more exhaustive analysis might be useful when more detailed information is available on the utilisation of biofuels in the transport sector. The results though show that a market for green electricity reacts on the scarcity of available biomass resources and that the effects of the biofuels directive should be taken into account when assessing the future value of renewable electricity.

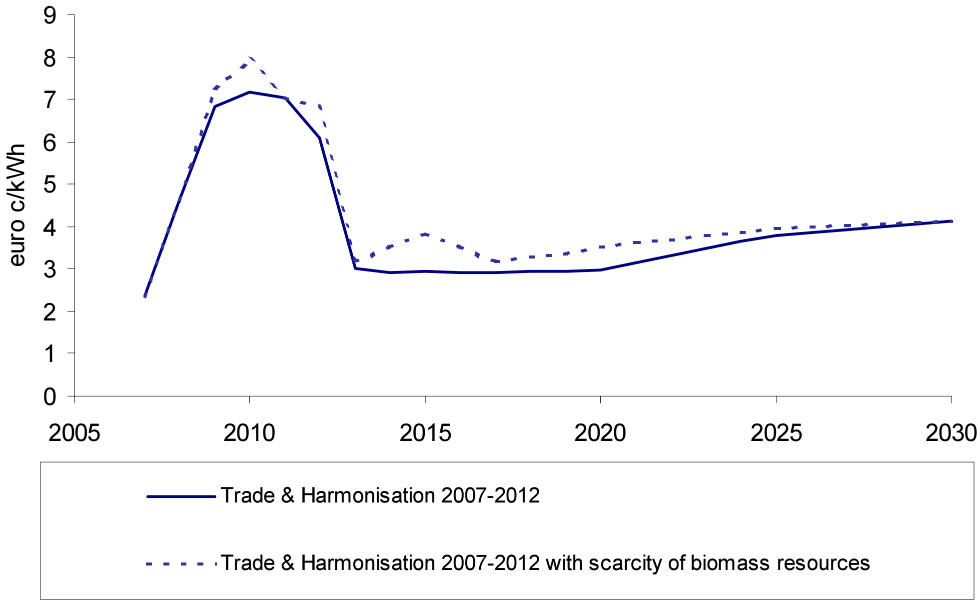


Figure 7.15 *Development of the TGC price in the Trade & Harmonisation scenario with and without scarcity of biomass resources*

Table 7.1 *Adjusted potential of biomass resources due to utilisation of feedstock in the transport sector*

[%]	2003	2004	2010
Energy crops	-5	-10	-20
Barley	-5	-5	-10
Maize	-5	-5	-10
Oilcrops	-20	-40	-80
Rapeseed	-20	-40	-80
Wheat	-5	-5	-10

7.5.3 Accession countries

On May 1st 2004, the European Union will be extended with 10 countries from Central and Eastern Europe (CEE): Cyprus, Czech Republic, Estonia, Hungary, Latvia, Lithuania, Malta, Poland, Slovakia, and Slovenia. In 2007, Bulgaria and Romania hope to join. Although the front runners have closed all the chapters of the Acquis Communautaire, most of them have agreed on transitional arrangements for specific chapters relevant for RES development such as Energy, Environment and Competition. Full compliance is expected by 2008 in most cases and certainly not later than 2010. Romania and Bulgaria have still some way to go before they can turn the page on these chapters of the Acquis but in their case too, significant progress is to be made in the lead up to the year 2010. By then, CEE countries would need to make their contribution to the 22% renewable electricity target as specified in the EU Renewables Directive.

The consequences of this enlargement on the development of the European market for electricity produced from renewable energy require further analysis, but several factors are likely to play an important role.

First, the allocation of national targets to CEE countries. Targets as negotiated in the accession process differ by country - ranging from 7.5% in Poland to 49.3% in Latvia. The large differences among Eastern European countries in renewables potentials, GDP growth and current energy intensities will probably create incentives for CEE countries to explore cost-efficient ways to meet their target as set in the EU Directive.

Secondly, the structure of the market. For most of the accession countries, it will be very difficult to achieve a significant increase in renewable capacity before 2010, due to a number of specific barriers, such as the current overcapacity for conventional electricity generation, the fact that electricity prices are still being subsidised in some countries, and the absence of specialised financing mechanisms (EnEffect, 2003). On the other hand, the potentials for renewable electricity generation in these countries might be significant enough to substantially contribute to the achievement of the EU target across Europe in an open TGC market. In any case, the introduction of renewable electricity targets for the enlarged EU would provide an additional incentive for the deployment of renewables in the accession countries.

8. COUNTRY CASE STUDIES

This chapter presents case studies carried out for four countries - Denmark, France, Germany and Spain. The case studies provide somewhat more detail in the specific situation of each country, and also serve as an illustration of the type of analyses that can be supported by the model.

8.1 Denmark - Will the announced national TGC system be implemented?

According to Danish energy plans the Danish support of new RES-E projects should be in the form of a national TGC market having a penalty price of 0.036 €/kWh for failing to buy certificates to fulfil the quota. The introduction of the TGC market has been postponed several times. As long as the announced national TGC scheme is not established, producers of RES-E will receive 0.013 €/kWh as compensation for not getting the certificate price. For wind power will this, and a feed-in tariff of 0.003 €/kWh, be the only payment additional to the spot market electricity price[49]. Biomass will regardless of a national TGC system receive a feed-in tariff, which secures a price of 0.040 €/kWh (including the spot market electricity price) and in addition to this get 0.013 €/kWh until the TGC scheme is implemented.[50] Due to the uncertainty surrounding the time for the introduction of the Danish TGC market it is interesting to analyse and compare two scenarios:

1) A reference scenario where a national TGC market in Denmark is introduced starting in 2004 and covering all renewables. In 2012 the national TGC scheme is replaced by a EU-wide harmonised TGC scheme.
2) A 'No TGC' scenario consisting of a continuation of the present support polices in Denmark until 2012, where the EU-wide harmonised TGC market replaces these support policies.

In order to investigate the consequences for RES-E in Denmark if the proposed national TGC scheme is established in 2004 and if the above-mentioned policies are continued, the ADMIRE REBUS model was used to run the reference and the No TGC scenario.

8.1.1 Comparing the two scenarios

The main finding of the Danish case study was that neither of the above-mentioned scenarios will be sufficient to secure compliance with the targets for RES-E supply in EU in 2010[51] (see Figure 8.1).

The proposed national TGC scheme in the period 2004-2011 showed however to be the most effective of the two scenarios, as the existing system with a fixed feed-in tariff of 0.017 €/kWh to wind power in addition to the obtained spot market price showed to be ineffective in expanding the existing wind power capacity. The long-term perspective with a common European TGC scheme does secure compliance with the targets. Denmark is even expected to become an important exporter of RES-E to other EU member states under the common European TGC scheme (see Figure 8.2).

---

[49] The spot market electricity price in Denmark is set to approximately 0.025 €/kWh in the period 2004-2010 in the ADMIRE REBUS model.

[50] Source: Bekendtgørelse af lov om elforsyning (LBK nr. 151 af 10/06/2003) §59a, §59b, §59d and §63

[51] Denmark has a target of 29.0% of the total gross inland consumption of electricity should be produced by RES-E sources in 2010 (Source: Renewable Energy Directive). We assume that the target will still be 29% in 2020. With an expected electricity consumption of 44,400 GWh in 2010 and 47,400 GWh in 2020 (Source: European Union Energy Outlook to 2020), this is equal 12,876 GWh and 13,746 GWh of RES-E production, which Denmark is obliged to consume in respectively 2010 and 2020.

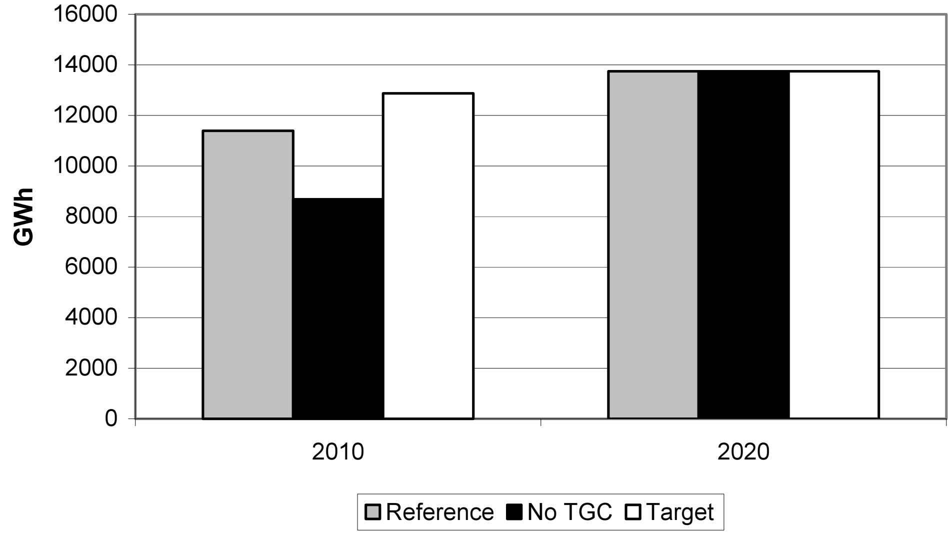


Figure 8.1 *Total consumption of RES-E in Denmark in 2010 and 2020 in the Reference and the No TGC scenarios, compared with the mandatory target of 29.0% of total electricity consumption put forward in the EU RES-E directive*

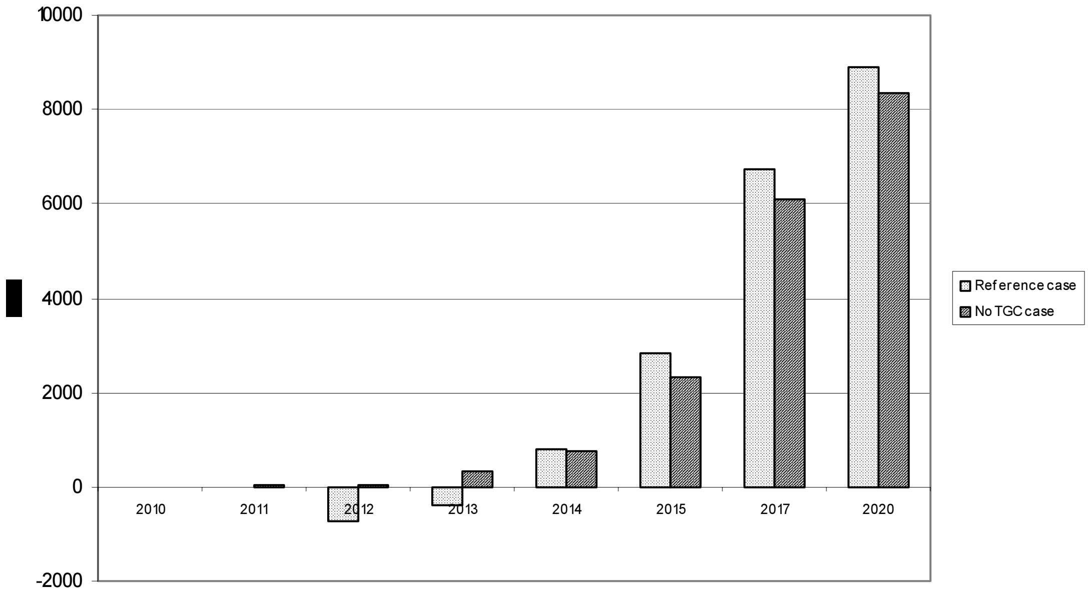


Figure 8.2 *Total Danish exports of RES-E under the reference and the 'No TGC' scenarios*

Findings in the Reference Scenario

In this scenario a national TGC scheme is introduced in 2004, which is supposed to run until the end of 2011, where the scheme is replaced by a common TGC system in the European Union by 2012. The introduction of the national TGC scheme has an effect on projects which are economic viable with a TGC price of 0.036 €/kWh or below, as this, when the model takes transaction costs into consideration, is equal to the penalty for non-compliance with the obligations on consumption. Running the scenario it was found that the price of the TGCs will be equal to the penalty price during the entire lifetime of the scheme and that the compliance with the target only will be 89% by 2010. One can in that way conclude that a penalty of 0.036 €/kWh for non-compliance with the obligations is not sufficient to achieve the target.

Findings in the No TGC Scenario

Continuation of the current system with a total support level of 0.042 €/kWh for wind power and 0.054 € for biomass in the period 2004-2011 will not result in compliance with the Danish national target for the share of RES-E in the electricity supply. The price incentives for biomass showed, however, to be sufficient to secure the use of the resource to the same extent as with introduction of the national TGC scheme. The onshore wind power production will suffer heavily if the national TGC system is not launched, to such an extent that the production from onshore wind turbines even decrease since there is insufficient incentives to install new capacity at the same rate as old capacity is worn out (see Figure 8.3).

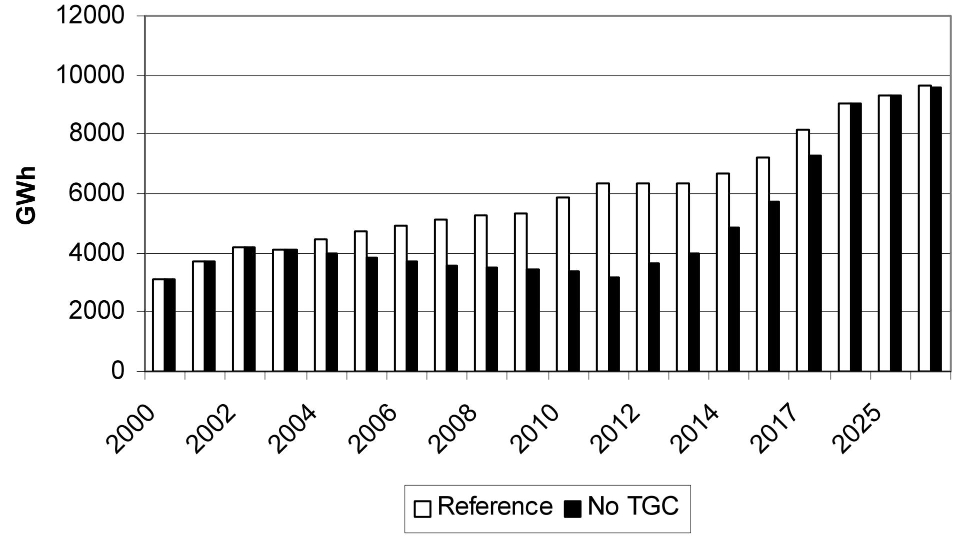


Figure 8.3 *The development of onshore wind power production in Denmark from 2000 to 2030 in the Reference and the No TGC scenario*

Below, in Figure 8.4 is illustrated how the system without national TGCs will have the greatest impact on the onshore wind technology, whereas biomass will be indifferent in both cases and offshore wind power will only be little sensitive to the different policies until 2010.

8.1.2 Conclusions

If the announced Danish TGC system is not implemented and the RES-E producers instead get 0.013 €/kWh in compensation for the lack of the certificates, the consequences will be serious for the development of wind power in the years to come. The use of biomass for electricity generation is expected to develop in the same way no matter if a national TGC scheme is introduced or not. Both systems illustrated in the scenarios shows in that way to be successful in promoting biomass to the same extent. There is in that way no reason for recommending one of the two policy traces instead of the other when looking at the policies' ability to promote biomass based RES-E.

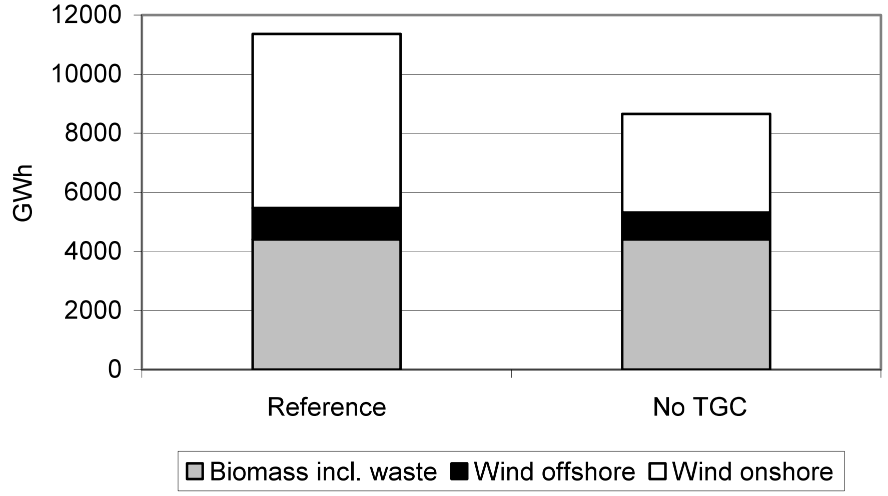


Figure 8.4 *The distribution of RES-E production on technology types in 2010 in the Reference and the No TGC scenario*

The development for wind - in particular onshore - is opposite to biomass threatened by continuation of the current policy. The case study shows that with the current policy, the installed capacity will even decline, as the installation of new capacity will not match the out phasing of old capacity. To avoid this development, the introduction of the national TGC scheme could be the solution.

Though a national TGC system will be more effective than the present policy it is not sufficient to comply with the target. The penalty for non-compliance with quotas of 0.036 €/kWh in the TGC system can therefore be concluded to be too low to achieve target compliance.

8.2 France - Comparing current support schemes to intensification or harmonisation

The objectives of France regarding production of RES-electricity are set by the Directive on the promotion of electricity from renewable energy sources at a level of 21% of gross electricity consumption. In 2001, the total French consumption amounted to 452,5 TWh, out of which 76,6TWh were produced from renewable energy sources. Taking into account the increase in the demand of electricity, by 2010 reaching 21% of the electricity consumption means consuming 113 TWh of green electricity, which is around 40 TWh more than in 2001.

RES-E support schemes in France are mainly based on feed-in tariffs. There are FIT for all RES-E sectors except for tidal and large hydro. They range from 4.5 ct/kWh for combustion of municipal waste to 15.25 ct/kWh for PV. Contracts last at least 10 years, with a maximum of 20 years for PV or small hydro. The tariff can diminish with time, for wind power for example : where the rate of 8.38 ct/kWh is guaranteed for first five years, after which level varies from 3.05 up to 8.38 *ct*/kWh depending on turbines' productivity.

There are also subventions for investment costs (PV, small hydro, biogas) that are national (FACE, ADEME) and can be completed by local authorities (regions or departments). Renewable electricity projects can also benefit from loans with preferential rates or from fiscal incentives when they are situated in the overseas departments and territories.

8.2.1 Technology mix, trade flows and costs in France

The following graph shows the development of the technology mix in France under a scenario where France continues present policies of support to RES-E.

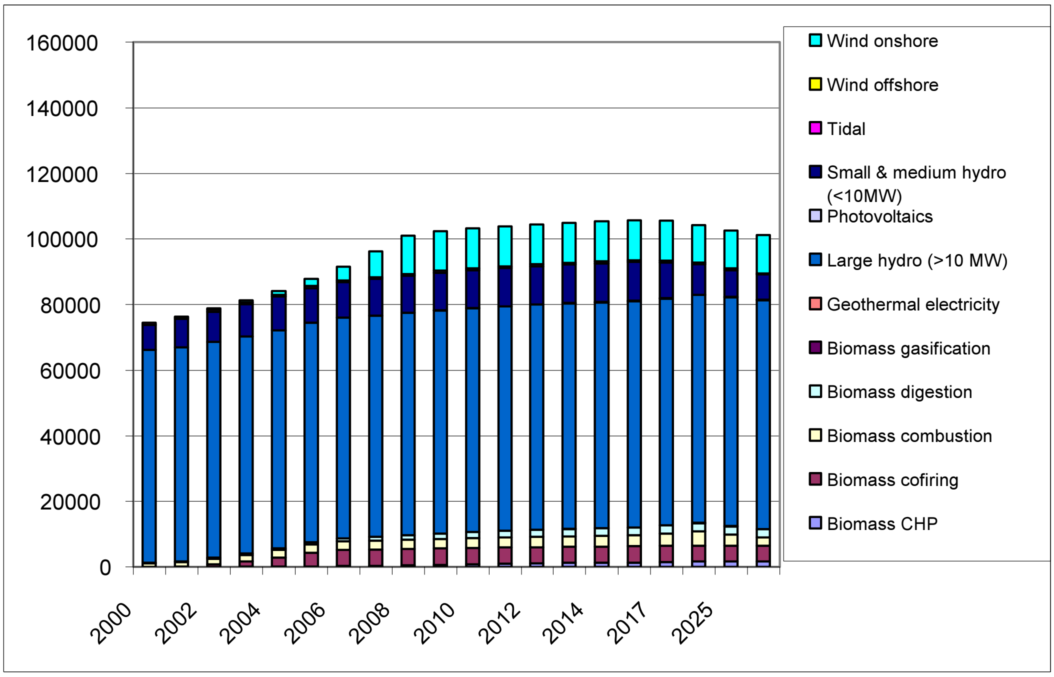


Figure 8.5 *Development of technology mix in France under Scenario continuation of present policies*

The technologies that will contribute the most to the development of RES-E are wind power on-shore and technologies related to biomass (especially co-firing). Their development will be stronger under other scenarios: intensification of present policies and harmonisation.

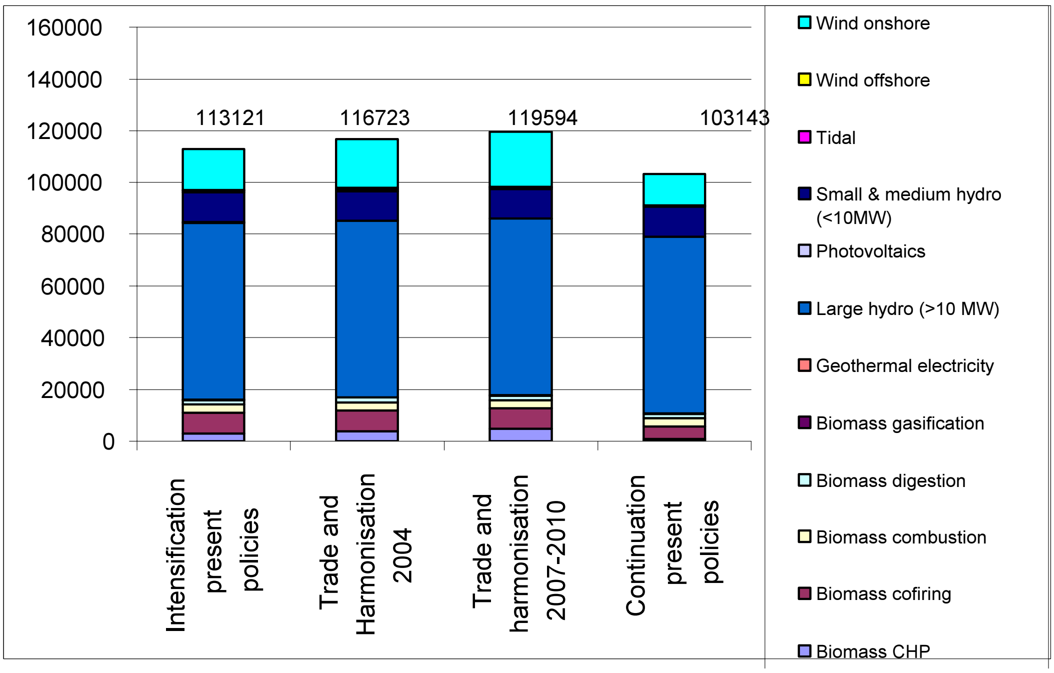


Figure 8.6 *Comparison of the French technology mix in 2010 under four different scenarios*

In the preceding graph dealing with two different chronologies to harmonise the European systems of support for RES-E, it is noticeable that the level of production achieved in 2010 is higher in the case of a mid-term harmonisation. An early harmonisation has less successful results for 2010 than a harmonisation starting in 2007, which enables France to produce up to 119 TWh. But in any way, harmonisation leads to a higher level of production than the continuation of current policies.

A comparison of net trade flows for green electricity from 2002 to 2020 under different scenarios confirms the fact that the most favourable scenario in case of France would be a harmonisation starting in 2007. An earlier harmonisation would have very negative effects on trade, presumably because the French renewable energy sectors are not mature yet, hence not competitive. A later harmonisation (starting 2012) would be profitable but less than if done in 2007. Other countries might have developed their sectors by then and French green electricity would be less interesting than when entering the market earlier.

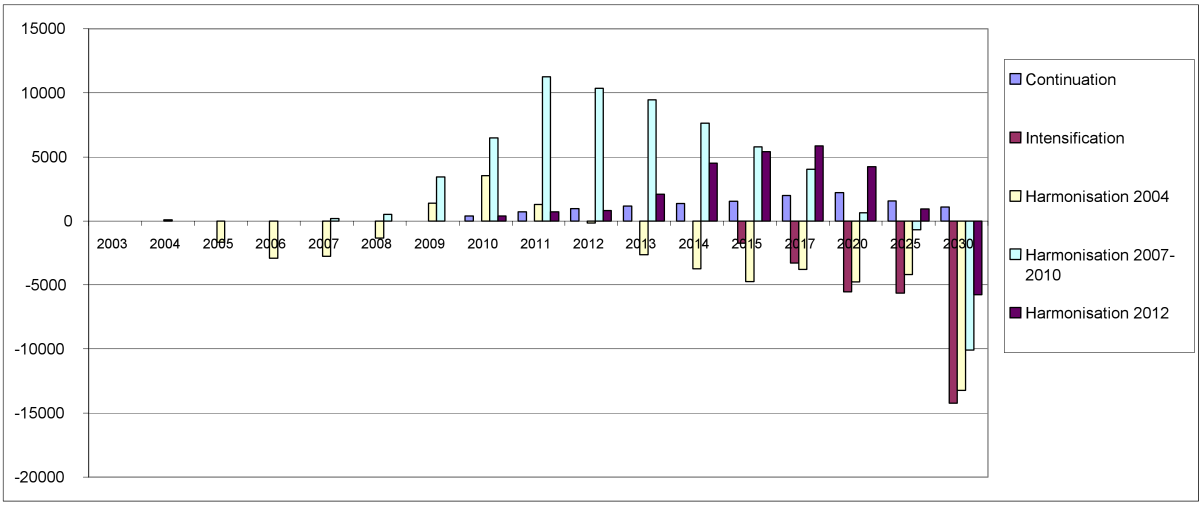


Figure 8.7 *Net trade flows for France under the different scenarios*

By continuing present policies, France does not manage to reach the targets set by the EU Renewables Directive but falls short of 10 TWh. The production would amount to 91% of the target. In fact, French producers export a small amount of green electricity, which shows that the domestic market does not provide enough incentive. Intensification of present policies is just enough to achieve the 113 TWh needed. European harmonisation of support policies through trade drives more production of green electricity in France than FIT.

A policy of trade and harmonisation brings about enough incentive to produce more than needed on the internal market. Exports are higher in the case of a harmonisation starting in 2007.

For an intensification of present policies which would be sufficient to reach the targets, the costs of the measures taken would increase by 3,5 times for bridging a gap of only 9% of production. From 759 million euros annually incurred in average from 2004 to 2010 if present policies are continued, the annual costs would rise up to 2675 million euros if they are intensified.

The introduction of quota obligations and trade in 2004 so as to meet the target in 2010 would lead to an annual average expenditures of 1322 million euros. A later introduction, which is a more probable case in today's European Union, starting in 2007 to reach targets in 2010, would cost 1390 million euros annually. Harmonisation with trade is therefore more cost efficient than the intensification of current policies regarding EU targets. France is in this sense in line with European trends.

Table 8.1 *Average annual expenditures for France 2004-2010*

Scenarios	[mln €]
Continuation of present policies	760
Intensification of current policies	2676
Harmonisation 2004	1323
Harmonisation 2007-2010	1391

8.3 Germany - The amendment of the Renewable Energy Sources Act

8.3.1 Renewable electricity in Germany until 2003

In the national strategy for sustainable development, which was presented in 2002, the federal government of Germany has formulated specific targets for the deployment of renewable energies (based on Die Bundesregierung, 2002, pp. 97). Accordingly a share of renewable energies of 4,2% of the primary energy demand and 12, 5% of the electricity demand is aimed at for the year 2010. By 2050 approximately half of the energy demand is supposed to be supplied by renewable energies. The federal ministry for the environment, nature conservation and nuclear safety has set an additional sub-target of 20% of the electricity demand in 2020. These targets are consistent with the EU directive 2001/77/ EG, of September 2001 of which article 3 formulates the EU-wide target of supplying a share of 22,1% of the electricity in 2010 with renewable energies.

In order to realize these targets the federal government has implemented several political incentives. The main element is thereby the Renewable Energy Sources Act (EEG). In 2000 the Renewable Energy Sources Act came into force and replaced the electricity feed-in act of 1991. The EEG increased and improved the compensation paid to the producers of renewable energy.

Electricity generation from sewage gas and landfill gas, hydro power and solar power with a capacity over 5 MW as well as electricity generation from biomass with a capacity over 20 MW is excepted. The payments vary from 6,19 Cent/kWh for wind power at favourable sites to 50,62 Cent/kWh for solar power. The compensation payments are payable for the period of 20 years, so as to provide financial security for investors. From the year 2002 on the compensation payments decline according to a specific pattern to encourage technological improvements and cost efficiency. Network operators bear the costs for the connection and possibly necessary grid adaptations. The operators of transmission networks have to level out the quantities of renewable energies fed into their grid and the compensation payments contributed. Electricity companies are obliged to take off and compensate the renewable energy. Under certain conditions the transmission of renewable energy to energy-intensive industries can be restricted, to alleviate the resulting costs for these companies. The compensation payments result at present in an increase of the electricity price of about 0,5 ct/kWh.

The Renewable Energy Sources Act has provided favourable conditions for the development of renewable energies. Under the Renewable Energy Sources Act there has been a distinct increase of the share of renewable energies in Germany. The contribution to the electricity generation has increased from 4,6% in 1998 to 8% in 2002.

Especially wind power has seen enormous growth rates. In June 2003 Germany had with 12.800 MW the highest installed capacity of wind power worldwide. This is more than 70 times the capacity of 1992 and has almost tripled since 1999. Before the enactment of the EEG hydro power has already contributed about 4% to the electricity supply. The potential for large hydro power is largely utilized. The EEG has effected a stabilization of hydro electricity generation in providing the environment for an profitable operation of hydro power with a capacity smaller than 5 MW. The development of photovoltaics has been promoted by the EEG and by the 100.000-roofs Solar-Electricity Program. The installed capacity has increased almost by 400%

roofs Solar-Electricity Program. The installed capacity has increased almost by 400% from 1999 to 262 MW in 2002. This development led to a considerable reduction of costs. The markets for biomass have not developed unitarily. Since the enactment of the biomass ordinance stronger activities can be observed especially in the area of wood and biogas. The electricity generation from biomass has increased by 400% from 1998 to 4200 GWh in 2002.

Regarding geothermal energy several projects - mainly for research purposes - are currently in their planning stage. The first geothermal power plant in Germany is this year due to go on line in Neustadt-Glewe in Mecklenburg-Vorpommern.

Although former and current political efforts still promote a continuous positive development of renewable energies in Germany the effectiveness of the legislation regarding the achievement of the 12.5% target in 2010 needs to be evaluated. The results of the scenario Continuation of Present Policies (see paragraph 6.1. of this report) clearly reveal that an unchanged continuation of present policies does not lead to this goal. The current design of the German feed-in tariff system would only lead to a share of about 9.8% RES-E consumption in the total domestic electricity consumption instead of the desired 12.5%.

8.3.2 The proposed amendment

In August 2003 the federal environment minister has submitted an amending law for the Renewable Energy Sources Act. With this amendment the compensation payments will be further differentiated, partly increased and partly reduced. The degression is extended to all payments. The renewable energy targets of the national sustainability strategy now form the guiding frame for the desired development of renewable energies. Table 8.2 summarizes the major changes proposed by the amending law.

The main changes in the level of payments affect wind power onshore, where the compensation is reduced by 0,5 Euro c/kWh. With this step a surplus promotion is to be prevented and also the incentive for installations on unfavourable sites is reduced. The payments for wind power offshore are extended on a period of twelve years. The degression is postponed until 2008. To open up the local biomass potentials the compensation for small biomass power plants is raised. Additionally a supplement is paid for electricity that is produced exclusively from plant matter and/or liquid manure to consider the higher costs in using renewable primary products. If innovative technologies, like thermo-chemical gasification, fuel cells, gas turbines or others are used an extra-premium of 1 Cent is paid. Also for electricity generated with landfill gas, sewage gas or firedamp an extra premium of 1 Cent is paid for the use of fuel cells. For solar power additional payments are introduced for on-roof and facade installations. The installation on open space is restricted. Also tariffs for small geothermal plants are increased, because experience has shown, that plants in development are smaller than expected and costs are higher. Degression is postponed until 2010.

Under certain conditions hydro power above 5 MW is included in the payments. To apply for compensation the plants have to be renewed until 2012 and this renewal has to increase the power by 15% and improve the ecological situation. Only the additionally gained electricity is compensated. The compensation for small hydro power is restricted.

To increase transparency a liability to release figures on the amount of energy supplied by the different techniques and the amount of compensation paid for this energy. Also for the difference cost and the overall costs of the act more transparency is intended.

Table 8.2 *Overview of current feed-in tariffs and proposed changes in the amending law for the Renewable Energy Sources Act*

		Old (29.3.2000)			New		
		Tariff (€ct./kWh)	Remarks	Degression	Tariff (€ct./kWh)	Remarks	Degression:
Hydro	up to 500 kW	**7.67**			**7.67**	only for plants commissioned after the year 2005	from 2005 , 1%/a
	500 kW - 5 MW	**6.65**	Electricity from first 500 kW receives 7.67€ct./kWh		**6.65**		from 2005 , 1%/a
Capacity expansion:	up to 500 kW	**-**			**7.67**	only additional capacity commissioned before the year 2012 is eligible	
	500 kW - 10 MW	**-**			**6.65**		
	10 MW - 20 MW	**-**			**6.1**		
	20 MW - 50 MW	**-**			**4.56**		
	ab 50 MW	**-**			**3.7**		
Landfill gas	up to 500 kW	**7.67**			**7.67**	+1€ct./kWh for fuel cells	from 2005 , 2%/a
	500 kW - 5 MW	**6.65**	Electricity from first 500 kW receives 7.67€ct./kWh		**6.65**	+1€ct./kWh for fuel cells	from 2005 , 2%/a
Grubengas	up to 500 kW	**7.67**			**7.67**	+1€ct./kWh for fuel cells	from 2005 , 2%/a
	500 kW - 5 MW	**6.65**	Electricity from first 500 kW receives 7.67€ct./kWh		**6.65**	+1€ct./kWh for fuel cells	from 2005 , 2%/a
Firedamp	up to 500 kW	**7.67**			**7.67**	+1€ct./kWh for fuel cells	from 2005 , 2%/a
	500 kW - 5 MW	**6.65**	Electricity from first 500 kW receives 7.67€ct./kWh		**6.65**	+1€ct./kWh for fuel cells	from 2005 , 2%/a
Biomass	up to 75 kW	**10.23**		from 2002 , 1%/a	**12.5**	+ 2,5 Ct for exclusive use of plants and liquid manure	from 2005 , 1%/a
	75 kW - 200 kW	**10.23**		from 2002 , 1%/a	**11.5**	+ 2,5 Ct for exclusive use of plants and liquid manure	from 2005 , 1%/a
	200 kW - 500 kW	**10.23**		from 2002 , 1%/a	**9.9**	+ 2,5 Ct for exclusive use of plants and liquid manure	from 2005 , 1%/a
	500 kW - 5 MW	**9, 21**	Electricity from first 500 kW receives 10.23€ct./kWh	from 2002 , 1%/a	**8.9**		from 2005 , 1%/a
	ab 5 MW	**8.7**	Electricity from first 5 MW like above	from 2002 , 1%/a	**8.4**		from 2005 , 1%/a
Geothermal electricity	up to 5 MW	**8.95**			**15**		from 2010 , 1%/a
	5 MW - 10 MW	**8.95**			**14**		from 2010 , 1%/a
	10 MW - 20 MW	**8.95**			**8.95**		from 2010 , 1%/a
	ab 20 MW	**7.16**	Electricity from first 20MW receives 8.95€ct./kWh		**7.16**		from 2010 , 1%/a
Wind (onshore)		**9.1**	for first 5 years	from 2002 , 1,5%/a	**8.7**	for first 12 years	from 2005 , 1,5%/a
		6.19	after first 5 years	from 2002 , 1,5%/a	**5.5**	after first 12 years	from 2005 , 1,5%/a
Wind (offshore)		**9.1**	for first 5 years	from 2002 , 1,5%/a	**9.11**	for first 12 years	from 2008 , 1,5%/a
		6.19	after first 5 years	from 2002 , 1,5%/a	**6.19**	after first 12 years	from 2008 , 1,5%/a
Solar		**50.62**		from 2002 , 5%/a	**43.44**		from 2005 , 5%/a

Based on the proposed feed-in tariff system the development of RES-E in Germany was simulated and compared to the situation without changes. The latter corresponds to Scenario I and is further referred to as '*OLD*'. The amendment of the Renewable Energy Sources Act was implemented as an additional scenario, which is further, referred to as '*NEW*'. Note that investments in capacity expansion at existing hydro sites were not included in this scenario.

8.3.3 Comparing present policy with the proposed amendment

Figure 8.8 shows the development of RES-E consumption in Germany under the present policy (*OLD*) and under the conditions proposed in the amendment of the Renewable Energy Sources Act (*NEW*). The first and most evident result is that in year 2010 the target of 12.5% (which corresponds to a consumption of approximately 76.7 TWh) will not be reached, neither under the old tariff system nor under the proposed new one. Although the amendment would lead to an additional consumption of about 6.7 TWh compared to the continuation of present policies, the 12.5% target would be reached by the year 2013 at the earliest.

Compared to the current situation where the target would not be met before 2020 the amendment undoubtedly advances the compliance to a more promising date. This applies especially when the realised consumption respectively production is considered as a lower bound due to the exclusion of re-powering or expansion of hydro plants.

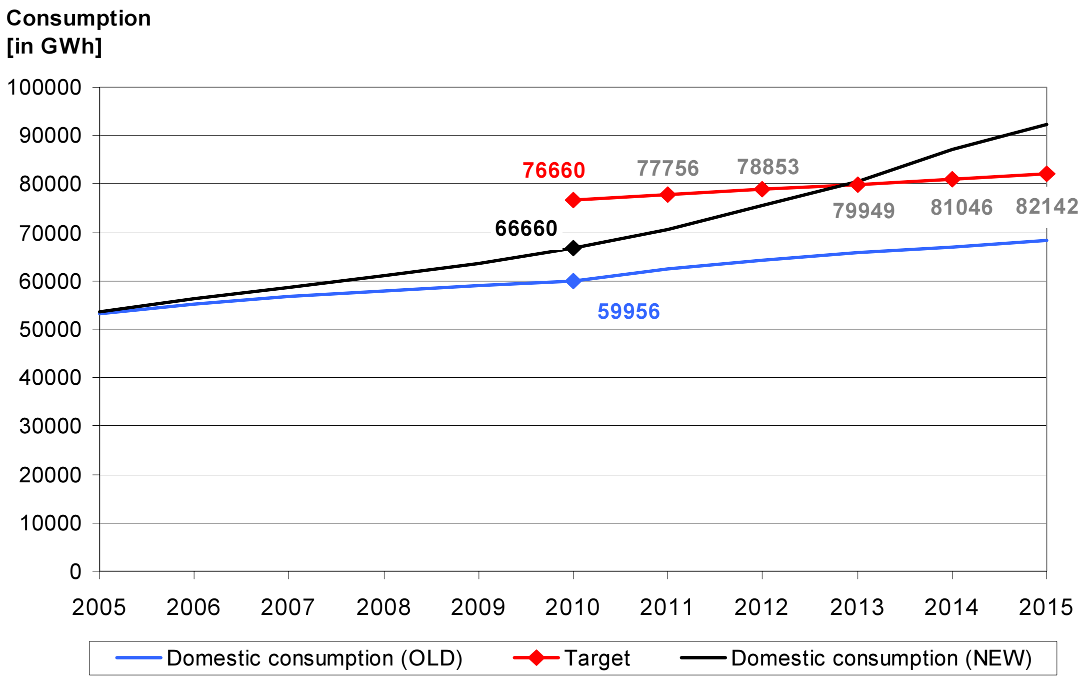


Figure 8.8 *RES-E consumption in Germany under continuation of current policies (OLD) and under the amendment of the Renewable Energy Law (NEW) and the 12.5% target*

Not surprisingly, the changes of feed-in tariffs affect the technology mix of RES-E production in Germany. Figure 8.9 shows the development of Germany's domestic RES-E production from 2005 until 2015 under the present policy (*OLD*) and under the conditions proposed in the amendment of the Renewable Energy Sources Act (*NEW*). Figure 8.10 displays the correspon-ding capacities employed in order to supply the domestic production.

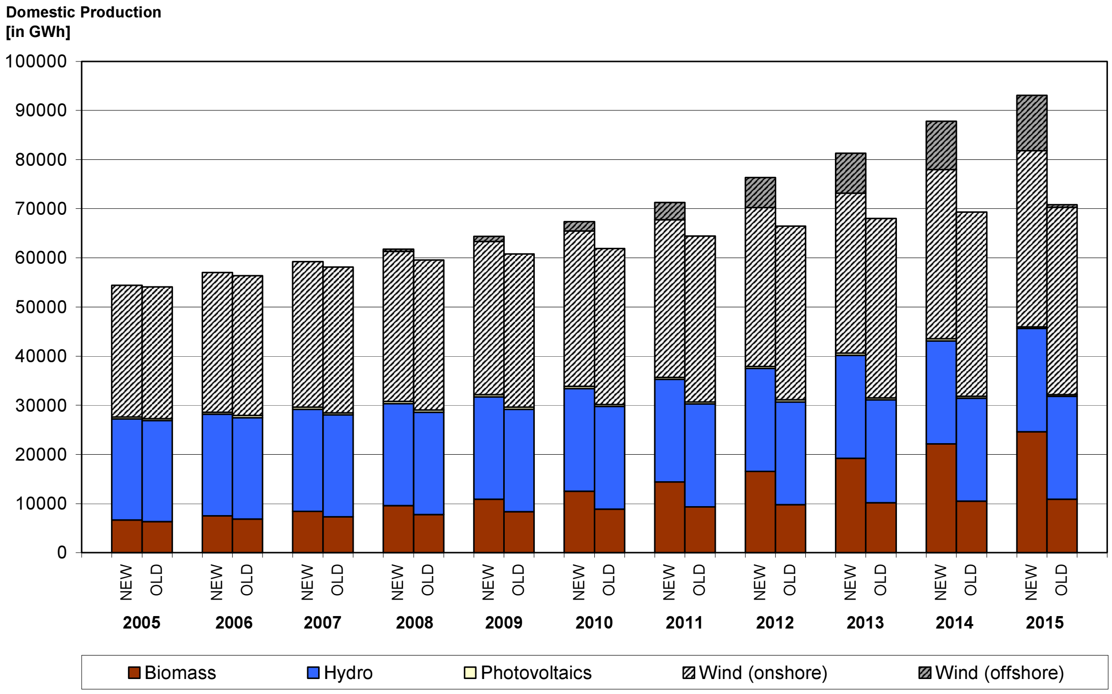


Figure 8.9 *Domestic RES-E production in Germany under continuation of current policies (OLD) and under the amendment of the Renewable Energy Law (NEW)*

The amendment mainly has effects on the development of two technologies: wind (especially offshore) and biomass. The prolonged period in which offshore capacities receive the higher tariff leads to an earlier utilisation of potentials. Under the current system offshore capacities enter the electricity system in the year 2015. The amendment facilitates economically viable investment already as of 2008. Offshore capacities go up to 4.4 GW in year 2015, which represents an electricity supply of approximately 11.2 TWh.

Consequentially the development of onshore wind capacities is also affected by the changes. Following the government's goal to exclude sites with unprofitable wind conditions from the promotion, the growth of wind onshore capacities slightly decelerates after the year 2010.

As compared to offshore wind, biomass capacities are immediately affected by the new act. In 2010 biomass production is about 40% higher under the new tariff system as under the existing one. The additional production mainly stems from CHP and combustion capacities.

The effects of the amendment on photovoltaics and geothermal electricity are negligible. In spite of the adjusted feed-in tariffs - lower tariffs for PV and higher ones for geothermal electricity - the employment of PV systems remains unchanged and an economically viable investment in geothermal technologies can not be expected until 2015.

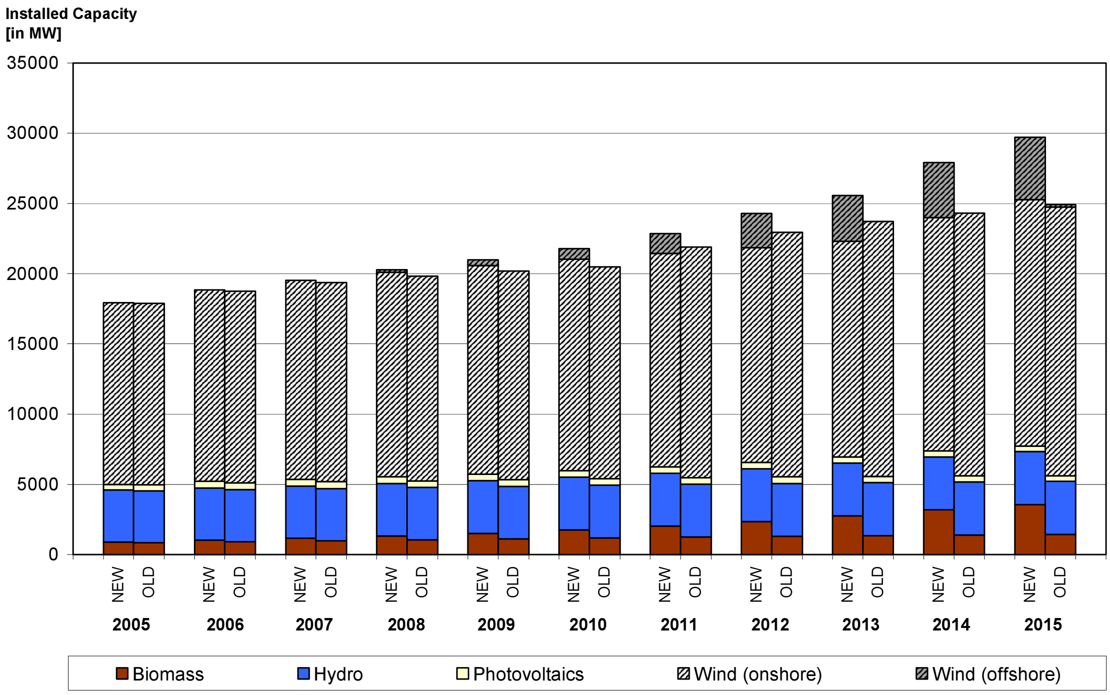


Figure 8.10 *Installed capacity in Germany under continuation of current policies (OLD) and under the amendment of the Renewable Energy Law (NEW)*

An important aspect of RES-E promotion, respectively the design of national support policies are the costs that arise from them. Table 8.3 shows the development of total government and end-user expenditures connected to the old and new design of the feed-in system as well as the specific expenditures calculated as a fraction of total expenditures over the domestic supply (average annual expenditures per kWh of domestic supply).

The cost figures show that higher realised domestic production arises higher overall expenditures. Additionally, the magnitude of specific expenditures rises more under the amendment than under current tariffs. An additional production of 6.7 TWh in 2010 would lead to an increase in expenditures of approximately 950 million euro. In relative terms: An extra of roughly

9% production in this year causes an increase in total expenditures of about 50%. Specific expenditures would be about 30% higher.

Table 8.3 *Total annual expenditures and specific expenditures connected to current and potential future feed-in tariff systems*

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
	Total annual expenditures (in Million €)										
Current system	1953	1966	1883	1928	1963	2002	2217	2260	2342	2424	2517
Proposed system	2088	2191	2222	2432	2658	2945	3305	3751	4291	4976	5293
	Specific expenditures (in €ct./kWh)										
Current system	3.68	3.57	3.32	3.33	3.33	3.34	3.55	3.51	3.56	3.63	3.69
Proposed system	3.89	3.89	3.80	3.98	4.18	4.42	4.69	4.96	5.33	5.71	5.73

8.3.4 Conclusions and outlook

The short analysis of the effects of the amendment showed that the proposed changes in the design of the feed-in system would further promote the investment in RES-E in Germany. The amendment would bring Germany's government closer to the 12.5% target in 2010 but also adds an additional cost burden on the demand side.

As shown in Chapter 6 of this report, the achievement of the target depends on the development of the electricity demand until the year 2010. The new design would lead to 66.7 TWh RES-E consumption in Germany. Provided that electricity demand is 10% lower than stated in (European Commission, 1999) the new feed-in system indeed would closely reach the target. Relative compliance would raise to approximately 96%. Roughly calculated the 66.7 TWh of RES-E consumption would represent 12.5% of a total electricity consumption of 533 TWh.

It should also be pointed out that, due to the exclusion of re-powering and expansion of existing hydro capacities from this case study, the result of RES-E production may rather be seen as a lower bound for the development in Germany under the proposed new tariff system.

The final design of the new act now is due to political discussion. In the short period of time after the proposal of the amendment it has received much and quite controversial feedback. The lobby associations of renewable energy producers widely welcomed the proposal. Criticism concerns the reduction of compensation for wind power onshore and also the restrictions for small hydro power. It is also stated that the compensation of electricity from large hydro is too much a concession. Positively noted were the increased and differentiated compensation for biomass and geothermal energy, the promotion of wind power offshore and the increased transparency in carrying out the act.

With the lobby of the industries there are quite different matters relevant. Lobby associations criticize the apportionment of costs and demand alleviation for industrial consumers. The costs for control energy and network expansion are suggested to be charged the producers of renewable energy. Associations also see the need for a temporal and financial limitation for the compensation payments. Furthermore efficiency criteria and monitoring are suggested.

The political discussion is only just arising and echoes the above-mentioned controversial issues.

8.4 Spain - Comparing current support schemes to intensification or harmonisation

The promotion of renewable energy in Spain is based on a fixed feed-in system, which provides RES-E producers with an incentive on top of the market price of electricity coming out of the pool (OMEL). The level of incentive is technology dependent and, in 2003, was in the range of 2,3 ct/kWh (Biomass) to 36,06 ct/kWh (small PV systems).

The scenarios analysed in this country-specific section are:
1) Continuation of Present Policies (CPP)
2) Intensification of current Policies (INTEN)
3) Harmonisation starting 2007 to 2010 (HAR07)

These scenarios are described more extensively in Chapters 6 and 7.

8.4.1 Realised production and policy costs

As expected, different scenarios show different levels of production during the analysed period. As revealed in Figure 8.11, a line representing a fixed percentage of total generation (through out the period) shows the projected target up to the year 2010. Looking at the Continuation of Present Policies scenario, it is important to note that, maintaining 2003 levels of RES-E support, the 2010 Target (75.2 TWh) is never attained (55.4 TWh). In the case of the INTEN scenario, the abovementioned target is reached since, as explained before, the scenario was set up in such a way that the Target was ‘forced’, and the required level of incentive in each period calculated by the model. The HAR07 scenario shows an opening to trade starting at 2007, for instance through a Tradable Green Certificate (TGC) system, which allows reaching the 2010 Target, again, by artificially fixing it.

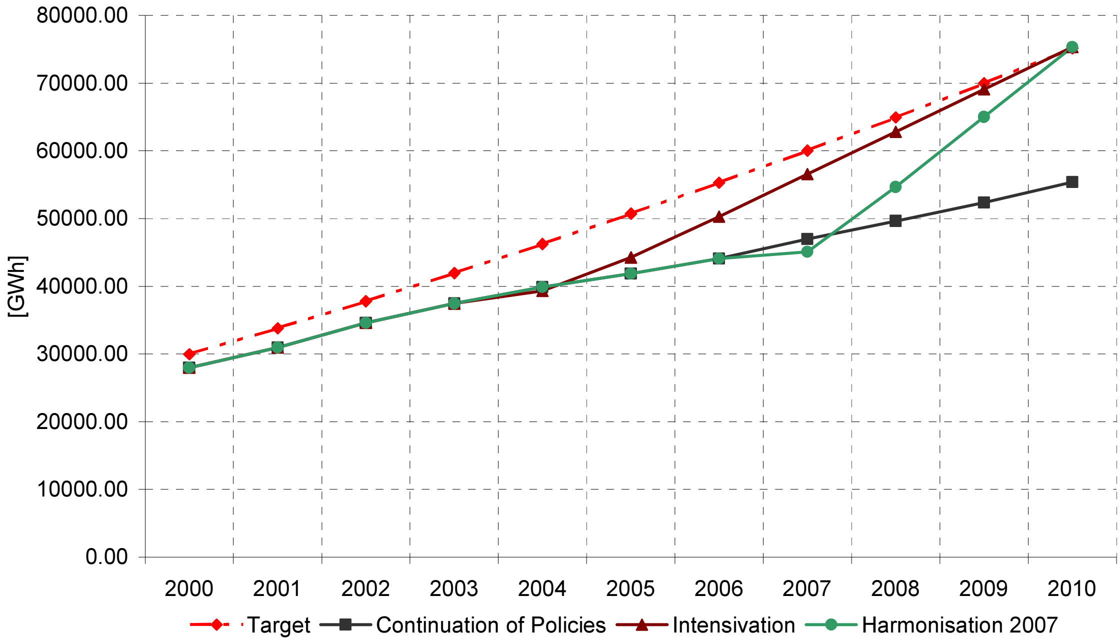


Figure 8.11 *Realised Production under different scenarios*

One important issue when looking at these scenario-results is the cost they have for the government, and hence, for society as a whole. These costs depend mainly on the specifications provided in each scenario.

The continuation of the present (2003) levels of incentives (CPP-scenario) is seemingly not sufficient to reach the 2010 proposed target. In Figure 8.12, the approximate expenditures related to maintaining the actual RES-E promotion scheme is shown by the CPP-line, being in 2010 close 850 Million €.

As shown in Figure 8.11, In the INTEN & HAR07 scenarios the 2010 target is similarly reached, however the costs to the Spanish consumers of doing so are quite different in one case and another. This can be seen in Figure 8.12 by looking at both scenario-lines. The estimated expenditures in the INTEN scenario for the year 2010 are 5.165 Million Euro, while that of the HAR07 scenario is 4.750 Million Euro. This difference is explained by the possibility of trading TGCs at the EU level, which clearly has the potential of reducing the bill of attainment to Spanish consumers.

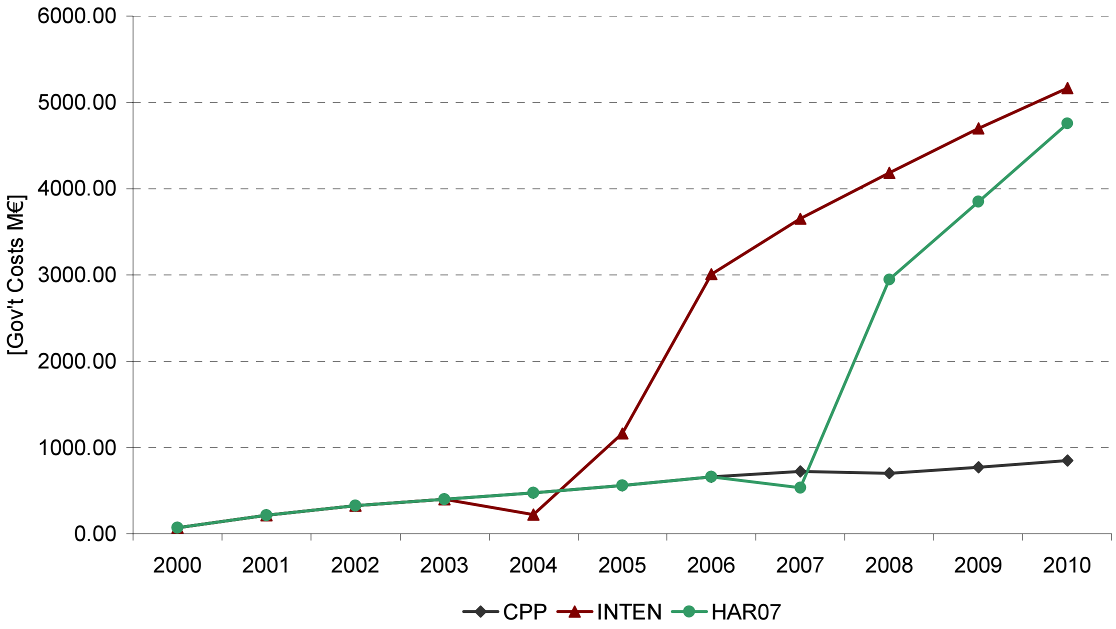


Figure 8.12 *Total expenditures under described scenarios*

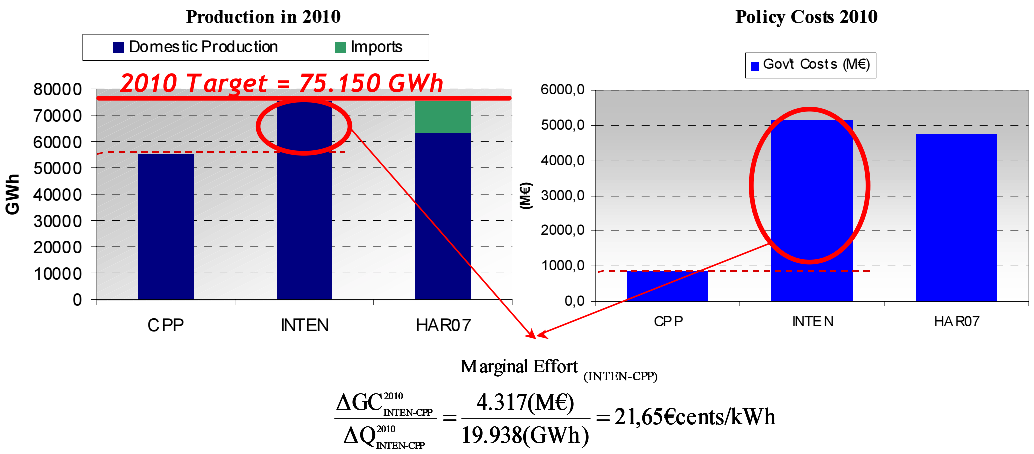


Figure 8.13 *Estimated Marginal Effort INTEN-CPP in 2010*

A closer look at expenditures reveals very interesting results for policy consideration. For instance, as shown in Figure 8.13, the marginal required effort (difference between INTEN and CPP costs, divided by difference between INTEN and CPP production in 2010) to attain the target is, approximately, 21,65 ct/kWh.

Some caution is however required when interpreting this. Since these expenditures are calculated through a combination of RES-E potentials and the cost of exploiting them, some degree of error is surely assumed which is directly related to the data used in the model. In the case of Spain, these data comes from various published sources but, importantly, the Ministry's National Plan to Promote RES-E[52] has been used for validation. Said this, what is clear from the analysis is that, at actual levels of support the 2010 target will not be achieved and, to attain it maintaining the present feed-in system would require an important extra-effort in terms of increased levels of support.

The average and marginal effort required to reach the Spanish RES-E target in 2010 is best appreciated looking at Table 8.4. The expected cumulative production and total expenditures for the period 2003-2010 in each scenario provide the information to estimate the Average and Marginal costs. In this sense the column 'Average expenditures' gives an idea of the expenditures attached to alternative scenarios for the analysed period. As expected, the INTEN-scenario is also the most expensive on average (5,17 ct/kWh), while the HAR07 reveals a considerably cheaper average cost (3,52 ct/kWh) mainly due to trade. The reasoning behind such a low average expenditures in the CPP-scenario (1,40 ct/kWh) is that some of the production accounted as RES-E does not get any incentive. So, even though in general the level of RES-E support in Spain is sensibly higher, on average this is not necessarily the case.

Table 8.4. *Cumulative Production & Expenditures 2003-2010 (Average & Marginal)*

Scenario	Expected Cumulative Expenditures [million €] (2003-10)	Expected Cumulative Production [GWh] (2003-10)	Average [ct/kWh]
CPP	5.142	367.640	1,40
INTEN	22.496	434.994	5,17
HAR07	14.183	403.344	3,52
Marginal Effort (INTEN-CPP)	17.354	67.354	25,77

Source: Admire-Rebus Model (2003).

8.4.2 Technology mix

The development of RES-E technologies depends, to a great extent, on the type and intensiveness of the promotion policy chosen. In figure 4, the mixed development of technologies achieved under different scenarios is presented for the years 2005 and 2010.

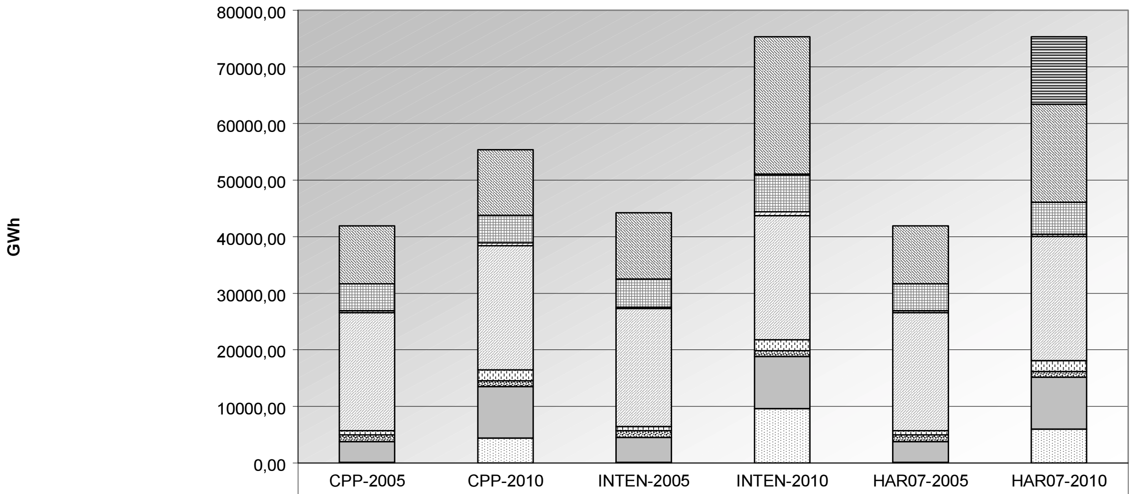
When analysing the percentage production changes from one period to the next among the three described scenarios two clear patterns appear:

1) Technologies showing equal or similar % increase or decrease along the three scenarios:
    a. *Biomass CHP and Digestion* register a 98% and 60% percentage increase respectively
    b. *Large Hydro* shows an increase of 5%
    c. *Biomass combustion* registers a decrease in the three scenarios (-14,7%).

2) Technologies with divergent % increase or decrease along the three scenarios.
    a. *Small and medium hydro* increases in the CPP-scenario only 3,3% from 2005 to 2010, while in the INTEN & HAR07 scenarios the increases are 22,8% and 16,2% respectively.
    b. *Wind-onshore* registers a similar but higher increase with 12% increase in CPP-scenario and 51,8% and 40,9% respectively in the INTEN & HAR07 scenarios.

[52] Instituto para la Diversificación y Ahorro de la Energía IDAE y Ministerio de Industria y Energía (1999). Plan de Fomento de las Energías Renovables en España. Madrid.

c. *Photovoltaic* technology reveals an interesting but expected result, showing a higher percentage increase in the CPP-scenario (34%) than in the HAR07-scenario (21,8%). The reasoning behind this is that in Spain production incentives are technology specific, so the CPP-scenario always provides for the development of some photovoltaic capacity. On the other hand, since the HAR07-scenario simulates a market opening through a sort of TGC scheme, where incentives are not anymore technology specific but rather cost oriented, in this scenario the increase is quite lower (21,8%).
d. *Wind offshore* technology is only developed in the INTEN and HAR07 scenarios, but the increase in the INTEN-scenario is 82% higher. This might be explained by the different objective decision in each scenario in terms of how much to promote each technology.



	CPP-2005	CPP-2010	INTEN-2005	INTEN-2010	HAR07-2005	HAR07-2010
Other Imports	0,00	0,00	0,00	0,00	0,00	11914,45
Wind onshore	10225,78	11618,54	11704,34	24295,25	10225,78	17302,37
Wind offshore	0,00	0,00	0,00	129,20	0,00	23,90
Small & medium hydro (<10MW)	4718,03	4881,48	5011,85	6495,61	4718,03	5629,49
Photovoltaics	317,46	482,00	187,71	682,55	317,46	405,84
Large hydro (>10 MW)	20895,47	21975,42	20895,47	21975,42	20895,47	21975,42
Biomass gasification	0,40	0,25	0,40	0,25	0,40	0,25
Biomass digestion	767,21	1880,30	767,21	1922,93	767,21	1892,34
Biomass combustion	1170,27	1020,53	1170,27	1020,53	1170,27	1020,53
Biomass cofiring	3667,17	9094,43	4390,88	9184,98	3667,17	9184,98
Biomass CHP	115,12	4432,60	115,12	9616,82	115,12	5973,97

Figure 8.14 *Technology Mix. Scenarios 2005 & 2010*

9. SENSITIVITY ANALYSIS

9.1 Set-up of the sensitivity analysis

Sensitivity analysis provides insights into the reaction of model outputs on changes of the model input parameters. It can be used as an instrument to assess two important topics connected to quantitative model-based analysis. These are:

- Identification of output ranges to test the robustness of model results, and
- Identification of important or influential model parameters.

In order to achieve this, a comprehensive joint sensitivity analysis on the basis of a Monte-Carlo simulation was carried out. The simulation results were derived from 400 ADMIRE-REBUS runs. In each of the 400 runs, values for relevant input parameters (i.e. lead times, electricity prices, pipeline success rate, growth limitations for technologies and growth limitations for biomass resources) that are key determinants for the model results, were drawn from uniform probability distributions around the model central values. The effects of the variations on RES-E supply (compliance with EU-wide or national targets), total costs (respectively total governmental and public expenditures) and - in cases where a harmonised market exists - the value of green electricity (TGC price) were investigated.

For the sake of clarity we concentrated the sensitivity analysis on two scenarios: (i) Continuation of Present Policies and (ii) Trade & Harmonisation 2007-2012.

9.2 Robustness of the results

In order to get an idea about the general behaviour of the model outputs a descriptive analysis of the Monte-Carlo simulation results is provided. A set of basic statistical (descriptive) indicators was calculated from the simulated model results. For a set of periods/years (i.e. 2000 to 2015, 2017, 2025 and 2030) the:

- mean value,
- standard deviation,
- 5^{th}, 25^{th}, 75^{th} and the 95^{th} percentile,
- median (50^{th} percentile).

of each of the mentioned model output parameter was calculated. An extensive overview of the sensitivity results is given in Table B.1, Table B.2 and Table B.3 in Annex B.

Compliance under continuation of present policies (Scenario A)
Figure 9.1 shows the development of relative compliance in Europe.[53] The sensitivity analysis affirms the difficulties in achieving the European target under the Member States' current policies. In the year 2010 the median of the sample is at a relative compliance level of 79%. This value is slightly below the initial result of 82%. In the same year the range of possible compliance levels extends from 51% to 107%. Half of the simulated results range from 67% to 89%.

Although the scenario analysis indicates a possibility that several countries achieve their national targets in 2010 (see Figure 6.3 in Paragraph 6.2.1 of this report) the chance that the EU

[53] The figure is a box-and-whisker plot. The upper and lower horizontal line (the *whiskers*) represent the extremum values of the simulated results. The *box* represents the space between the 25^{th} and the 75^{th} percentile of the simulated cases, i.e. 50% of the results are located within this box. The horizontal line within the box indicates the median.

reaches its overall target is very limited. The cases in which compliance is achieved in 2010 are below 10% of all cases in the sensitivity analysis.[54] This situation does not change considerably until the year 2030 where slightly more than 25% of the cases lead to compliance[55].

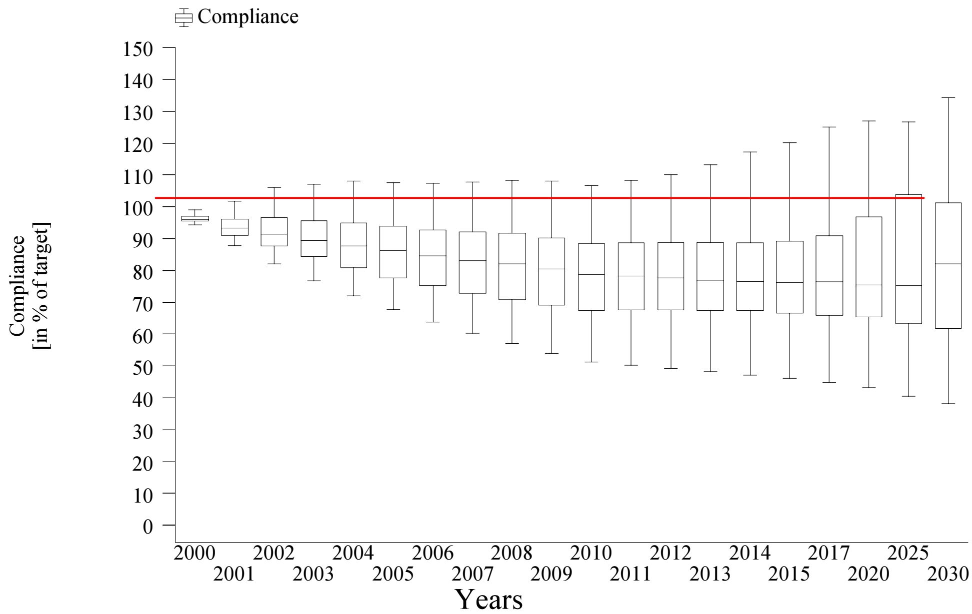


Figure 9.1 *Relative compliance in the scenario Continuation of Present Policies*

The value of green electricity in Scenario E - Trade & harmonisation 2007-2012

One of the most relevant results of this scenario is the development of the price for renewable electricity. Figure 9.2 describes the dispersion of the equilibrium price from the beginning of the transition period in 2007 until 2030 (the corresponding results can be found in Table B.3 in Annex B). The annual median values are close to the results of the initial scenario results (see Paragraph 7.4).

In year 2012 more than 75% of the calculated sensitivity runs result in an equilibrium price higher than 6.2 ct/kWh. Especially during the transition period between 2007 and 2012 the range of possible prices is substantially broader than in the following years. The probability that the price is at the penalty level is 50% or higher in the years 2009 until 2012. After a harmonised market is fully established in 2012 the range of possible prices becomes even larger. The highest possible range can be observed in the year 2014. The price level of the next years can be considered much more stable and robust. The reason behind the high dispersion and the tendency towards higher prices is given by the uncertainty that some countries face in reaching their targets until 2012. The possibility of non-compliance is confirmed by the results the sensitivity analysis produces for EU-wide relative compliance. In the year 2012 both the median and the mean of relative compliance are below 100%.

[54] Only 27 out of 400 cases of the total sensitivity analysis result in EU-wide compliance in year 2010.
[55] Note that in the longer run, the assumption that countries merely continue their present policies quickly looses significance.

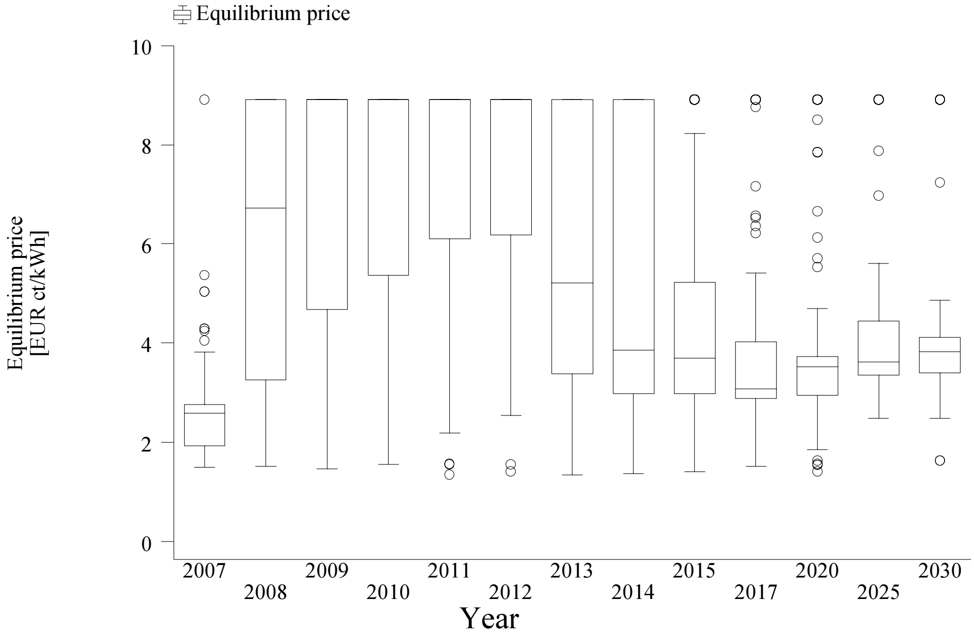


Figure 9.2 *Development of the equilibrium price in the Trade & harmonisation 2007-2012 scenario*

Robustness of cost estimates in both scenarios
Figure 9.3 describes the evolution of the total expenditures related to the supply and consumption of renewable electricity in Europe. Again, the median values are relatively close to the initial model results. Not surprisingly, the magnitude of these values is always equal (in early periods) or higher in the Trade & Harmonisation scenario. According to the dispersion of the equilibrium price also the expenditures exhibit a larger spreading during and directly after the transition period.

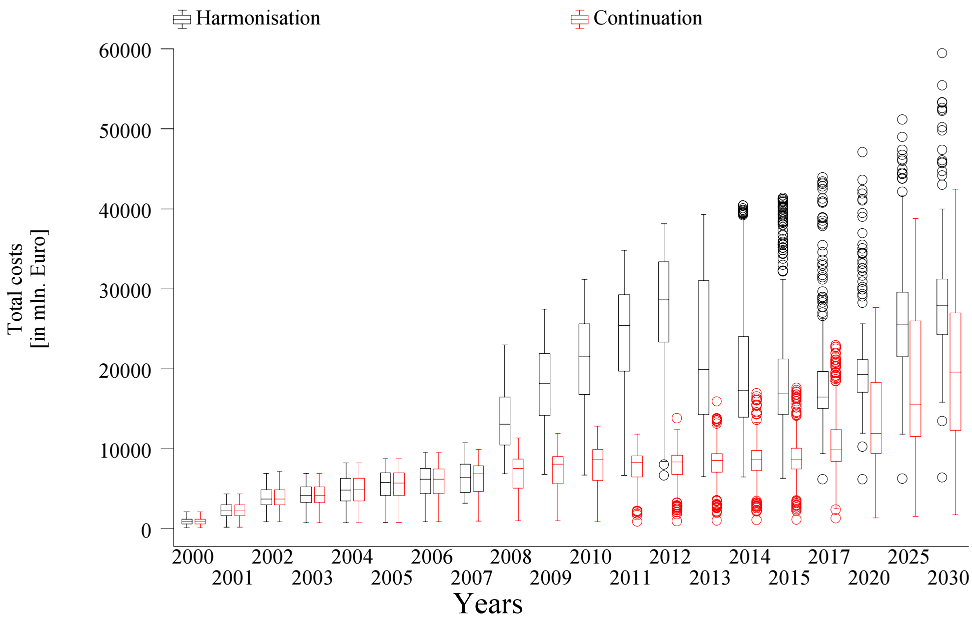


Figure 9.3 *Comparison of total government and end-user expenditures in scenarios Continuation of present policies (Continuation) and Trade & harmonisation 2007-2012 (Harmonisation)*

9.3 Relative importance of parameters

The relative importance of the input factors was analysed by employing a statistical meta-modelling approach. This approach analyses the dose-response mechanisms of the initial model. So the meta-model approximates the underlying decision- or simulation model, which is seen as a black box. The 400 simulation runs were used to create input and output values, which can be considered as observations. A linear regression model for each of the simulated output values has been used in order to achieve the coefficients respectively the relative impact of changes in the parameterisation space of the input parameters. The results of the regression models can be found in Table B.4 in Annex B. Based on the estimation results, elasticities were calculated that allow for a direct comparison of the input parameters' impact on the model results.

It should be noted that this meta-modelling approach is neither capable to substitute the actual ADMIRE-REBUS model nor to produce results which are comparable with the initial ADMIRE-REBUS output. It is feasible, though, to derive robust - rather qualitative - judgements of relative differences.

9.3.1 Impacts on realised supply and total expenditures

The effects that the analysed input parameters have on the levels of total expenditures and realised RES-E supply are shown in Figure 9.4. According to the results of the regressions we only display those parameters that have a significant impact on the output values (significance level 5%). Subject to this constraint, the lead times and maximum growth rates for technologies do not significantly influence RES-E supply and total expenditures in any of the examined scenarios. The same applies for the effect of the maximum biomass resource growth rate on the total expenditures in the Trade & Harmonisation scenario.

When present support policies continue to be in force, the most influential input parameter is the reference electricity (commodity) price, regarding its effect on supply as well as on the expenditures, followed by the pipeline success rate[56] and the maximum growth rate of resources. Especially in the first periods the reference price has a very large impact on the development of total expenditures. All output parameters are positively correlated to the input parameters.

The situation is different in the Trade and Harmonisation scenario. Realised supply is still positively correlated to all input factors where a significant influence has been found, but in comparison to a situation without policy changes, the importance of the input parameters declines. The relative importance also changes. The resource growth rate and pipeline success exhibit a similar relative impact but the reference electricity commodity price is no longer the most influential factor. Obviously, high electricity prices still promote the deployment of renewable electricity, but now the main drivers are European and member states' RES-E targets and the market value of green electricity.

In the harmonised market, total expenditures are negatively correlated to the pipeline success rate. Compared to the Continuation of Present Policies scenario where additional realised supply imply an additional cost burden due to unchanged support schemes like fixed premiums, feed-in tariffs or subsidies, a harmonised market efficiently distributes the expenditures across the market parties. Thus, the demand can directly benefit from cost reductions on the supply side.

[56] The pipeline success rate is one of several parameters limiting the speed at which the realisable potential for RES-E can be installed. It is a measure for the amount of renewable projects realised, as compared to the amount of projects for which feasibility studies are started (which 'enter the pipeline').

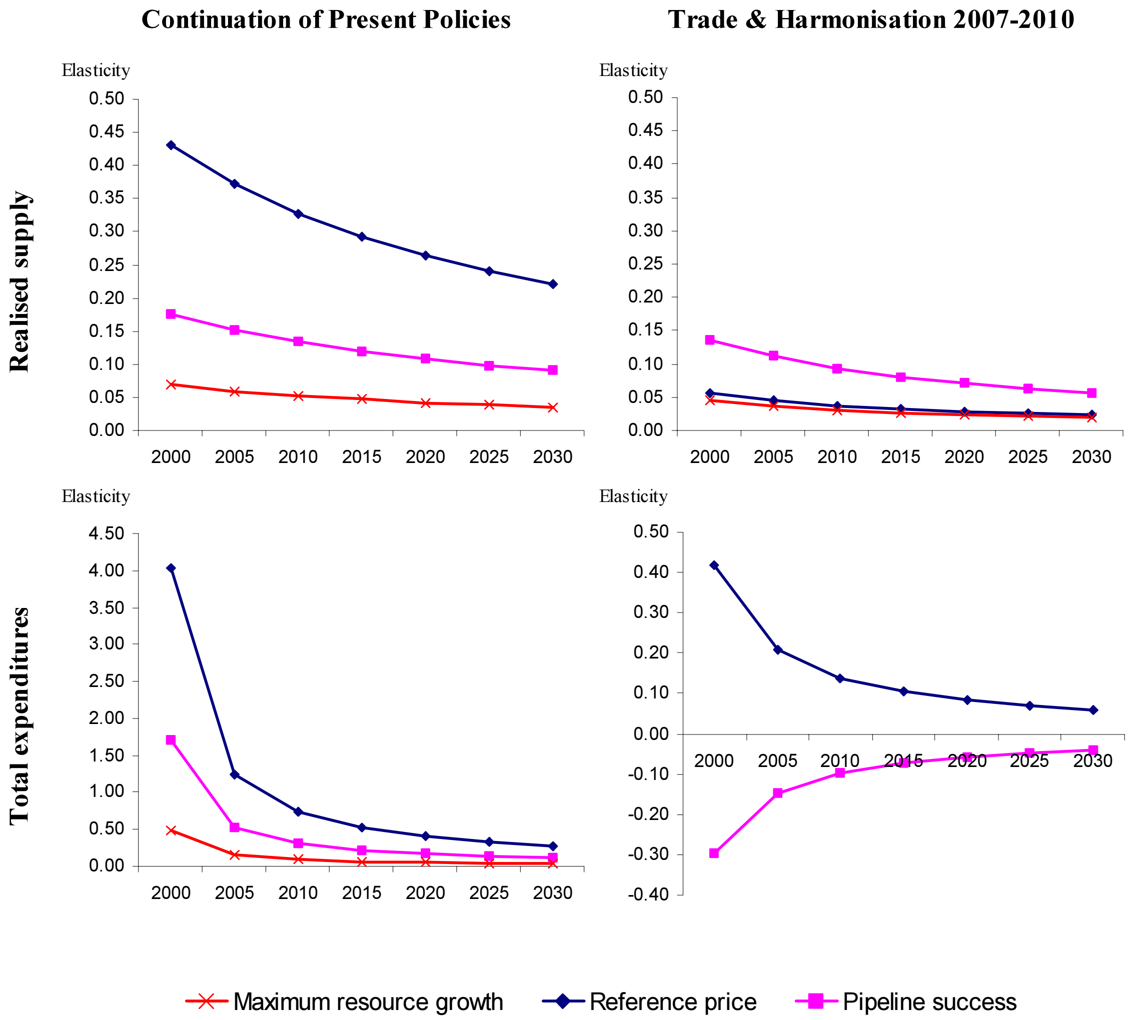


Figure 9.4 *Impact of input parameters on the magnitude of realised supply and total expenditures in the scenarios Continuation of Present Policies and Trade & Harmonisation 2007-2012*

9.3.2 Impacts on the value of renewable electricity

Figure 9.5 shows how the reference price, the pipeline success rate, lead times and the maximum biomass resource growth rate affect the equilibrium price in the scenario Trade & Harmonisation 2007-2012.[57] In absolute terms the pipeline success rate has the highest influence on the price followed by the reference price and the biomass resource growth rate. Not surprisingly an increase of these factors leads to a decrease of the equilibrium price. The only factor that has a positive impact on the equilibrium price is the lead time. But the magnitude can be considered as relatively low as compared to the impact of the other factors.

[57] Note that the overall growth limitation of technologies is omitted here because the impact of the parameter on the equilibrium price is not significant (significance level 5%).

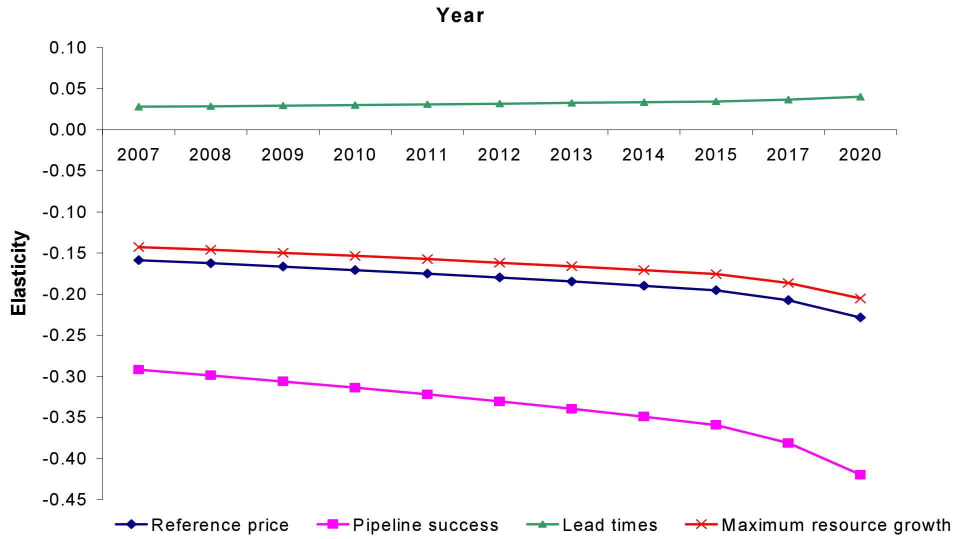


Figure 9.5 *Relative importance (elasticities) of input factors on the magnitude of the equilibrium price*

10. CONCLUSIONS AND RECOMMENDATIONS

The ADMIRE REBUS project has provided an analysis of the challenges to investors in renewable electricity in a EU market in transition, characterised by a large variety of policy goals and support systems. By recognising these challenges, an investor may be able to take measures that reduce the risk of a failed investment project. Although the challenges are plenty, so are the market opportunities. The investment in and deployment of RES-E technologies within the EU have never been as large as it is today. Still and in addition to this, the ADMIRE REBUS results indicate that if the indicative targets of the EU Renewables Directive are to be reached in 2010, much more RES-E has to be deployed.

10.1 Challenges: Risks and lead times are caused by various factors

Investors have to face complex administrative procedures in all Member states. These procedures vary according to country as well as according to technology, which implies a lot of information search for investors. Moreover, delays for obtaining authorisations are not the same throughout the European Union, some countries offering much quicker procedures than others. These delays have a direct impact on the moment when cash flows start to come in. These lead times are caused by a range of factors, such as local opposition, either from local authorities or from inhabitants.

Investors have the opportunity to smoothen the process by making early contacts with local actors. Projects should be explained at a very early stage in detail to the population as well as to local authorities. Negative reactions can be strong when people feel by-passed. They have to feel their expectations are being taken into account. When this strategy is used, rejections of proposed projects are less frequent. This is not only an effect of diplomatic skills. The higher level of acceptation is also due to the fact that project developers can modify their initial plan so as to make it more acceptable by local actors.

Apart from the lead time and transaction cost before the production at a new renewable plant can start, there are many other factors that may create fluctuation in the revenue of an RES-E investment and thereby make it more risky. However, a wide range of measures exists that can be used to reduce this risk.

10.2 What is the future of renewable electricity in Europe?

The study has shown that the market for renewable electricity will continue to be shaped by policies, because most technologies still depend on financial support in order to survive in a liberalised power market. Therefore the ambition levels of national governments and the EC will be the major determining factors for deployment of renewable electricity in the present decade and beyond. Of course, these ambition levels are politically determined and can be influenced by various external factors, such as the introduction of emission trade, the development of a market for biofuels and the enlargement of the EU in the next years. These external factors will probably have a significant impact on the prospects of renewables in Europe.

Technology development depends on the regulatory framework

Comparing different scenarios, it is clear that achievement of the EU targets will to a large extent rely on wind onshore and biomass, in addition to a stable contribution from hydropower. The development of other technologies is more dependent on the type of policies used and on the ambition level of these policies. For technologies such as PV, specific support covering the relatively high cost will remain crucial in the short run. Offshore wind is less competitive than other renewable major technologies, however by a rapidly narrowing margin. This means that under generic policies - such as a TGC market where all technologies compete - the level of the market price will determine its prospects.

For wind onshore, a large growth is expected under all scenarios. Main countries are the UK, Germany, France and Spain. The use of biomass will increase in general if the policy ambition level increases. Biomass-fired cogeneration plants and co-fired facilities will benefit more from the introduction of a TGC system than other biomass technologies. With respect to the deployment of different biomass resources, agricultural residues and forestry residues show the largest growth.

Long-term renewable electricity price expectations
If a EU market for tradable green certificates emerges, the certificate price directly depends on the level of the demand created in this market, in other words the ambition level of policies translated into quota. Assuming that the quota are based on the EU targets for 2010, the market price is expected to increase rapidly in the transition period up till 2010, when the market is adjusting to the increase in demand level. In this period, TGC prices are expected to be in the range of 5-6 ct/kWh. This price is additional to an average electricity commodity price of 3 ct/kWh. In the period beyond 2010, the level of the TGC price is directly dependent on whether new targets are agreed in the EU. If the ambition level does not further increase, and targets will only see a moderate increase in absolute terms as a result of the growth in electricity demand, the TGC price will stabilise on a lower level of 3-4 ct/kWh. Given this clear relationship and the time horizon of investors beyond 2010, it would be in the interest of further development of the market if governments would already start setting targets for 2015 or 2020.

Trade flows
When the market for electricity from renewable resources is opened further for international trade, some countries will be importers of RES-E while others will be exporters. In this respect, the main question is which countries will open their markets and when. In the scenarios involving trade for all EU countries, the main importers will in 2010 be Spain, Portugal and Italy, while the largest exporters will be Denmark, Germany, UK and Ireland. Beyond 2010, Sweden also becomes and exporting country, which is due to the growth of onshore wind.

10.3 Will the EU Renewables Directive targets be met?

In October 2001, the European Parliament adopted the Directive on Promotion of Electricity from renewable energy sources. Article 3 of this Directive sets an indicative target of a renewable share of 22.1% of gross electricity consumption, which is translated into indicative targets for each Member State.

The ADMIRE REBUS model has been used to assess whether the European and national targets might be reached by applying the existing policy schemes at least until 2010[58]. The results indicate that at baseline electricity market conditions[59], only a few Member States - Austria, the Netherlands and the United Kingdom - are likely to reach their targets in 2010 under continuation of present policies. Overall, the EU consumption of renewable electricity would be 82% of the target, or a projected deficit of almost 120 TWh.

---

[58] It should be noted that it is not until October 2003 that the European Commission will evaluate to which extent the national governments have transposed the directive into their national support policies. This would be the most appropriate moment for an evaluation of national efforts. In this sense the ADMIRE-REBUS assessment based on those policies planned or implemented by early 2003, should be regarded preliminary, because Member States still have time to revise their support schemes or to introduce new ones.

[59] Baseline electricity market conditions are a total electricity demand of 3054 TWh in 2010, with overcapacity continuing and a relatively low carbon premium, resulting in relatively low wholesale electricity prices of 3 €c/kWh on average (Section 2.2).

Of course there is a large uncertainty connected to the assumption that countries will continue their present policies. It is likely that in the years to come, they will adapt their policies in the light of the targets. For instance, the Netherlands reaches its target partly through imports from countries not achieving their own target, which hardly seems sustainable. Another special case is Ireland where the current policy is only defined until 2005. Therefore, a 'policy gap' in the period until 2010 is the main reason for Irelands non-compliance and additional analysis shows that Ireland is not expected to have major problems achieving the target in 2010. Furthermore, the analysis of individual countries demonstrates that not the type of support scheme but rather the way it is implemented and the level of support determine its effectiveness, although the efficiency might differ.

Strategies

Several strategies can help to bridge the gap between target and projected consumption. One strategy is an intensification of current policies. Most countries can achieve their target by increasing their average support level moderately. However, for Spain, Italy, Belgium, Portugal and Luxembourg, costs of this policy intensification will rise to very high levels. This is due to the large growth of installed capacity needed in these countries in a relatively short time period. Investors in these countries (but also in other Member States) have to face substantial delays caused by administrative barriers and local resistance. Therefore, measures aiming at removing implementation barriers can increase the compliance rate for the EU as a whole from 82% to 89%.

Another strategy could be to introduce international trade in a completely harmonised market combined with mandatory targets for 2010. The Harmonised Europe scenario has been used to maximise the chances of achieving the target by assuming that trade is facilitated in a TGC market from 2004 on. Model results show that the introduction of international trade is the most cost-effective way of achieving the targets. This is mainly due to optimal use of comparative advantages - renewables are best deployed at those locations where potential is available at the lowest costs. Still, some countries may benefit more than others. For Belgium, Italy, Spain, Portugal, and the Netherlands, importing a certain amount of renewable electricity is much cheaper than completely achieving their target domestically. On the other hand, producers in the UK, Ireland, Denmark, France and Germany can explore new export markets once international trade is introduced. However, other policy goals, such as local employment or environmental considerations can cause governments to prefer (a certain share of) domestic production above import.

Finally, given the fact that the targets are expressed as a share of electricity consumption, measures to reduce electricity demand could also be considered. For example, if all countries would have a 10% lower electricity demand than projected in (European Commission, 1999) overall compliance would increase to 91% without additional costs. Likewise, achieving these 10% lower targets on the basis of trade in an international market would reduce additional expenditures significantly, not only due to a lower RES-E production, but also due to a more moderate development of the TGC price.

Costs of achieving the targets

Compared to a continuation of present policies, the introduction of mandatory targets will significantly increase costs, since it involves a much larger deployment of renewable electricity in a relatively short period. Total additional production costs may increase from 4.7 bln € to 10 bln € to achieve 662 TWh instead of 543 TWh, due to a much larger share of the more expensive technologies such as offshore wind. In the 'Demand Side Management' scenario where 10% lower electricity demand leads to similarly lower targets, production costs are 6.5 bln €. The total government and end-user expenditures show the same sensitivity to the level of electricity demand, ranging from 14.4 bln € in the 'Demand Side Management' scenario to 24.4 bln € in the scenario where trade is introduced in 2004 to achieve the targets. Note that the introduction of emission trade is expected to have an increasing effect on the commodity price for electricity.

Indicative calculations have shown that in a 'high electricity prices scenario', total expenditures drop to 20.7 bln €.

Although in the initial phase, there are substantial additional expenses to be incurred for completely achieving the indicative targets by 2010, it is worthwhile considering the long term benefits which may be derived from technology development of not yet commercialised technologies. An example is geothermal electricity, which under the ambitious scenario is expected to develop and under the continuation scenario is expected to remain on a steady state. Therefore, both investors and policy makers have an interest in finding the most efficient policy.

Trade and harmonisation
International trade and harmonisation of the support framework are closely related, but not the same. The analysis has shown that international trade can introduce flexibility in the market and allows for renewables deployment in the most efficient way. Therefore it is worthwhile to examine the possibilities for facilitating trade, even although harmonisation of the support framework is not likely to be introduced before 2007-2010, if at all.

International trade of renewable electricity requires a common verification, registration and monitoring framework. Guarantees of Origin (GO) could provide this and need to be in place in October 2003 conform the Renewables Directive. However, a first inventory of Member States' progress in implementing a system of GOs (White et al., 2003) already shows a large diversity of designs. Therefore, international coordination on the design and comprehensive implementation of these GOs should ensure that they can provide the administrative basis for an international trading system. Finally, trade between countries using different support schemes may lead to interactions due to different support levels, which will have to be addressed.

10.4 Recommendations

The target of 22% renewable electricity in the EU by 2010 is achievable, but does require policy intensification in many EU Member States. In this respect, timing is crucial. Due to the effects of lead times and other implementation barriers, a significant increase in renewable electricity production takes a number of years. The shorter the time period to realise a certain relative increase in deployment, the higher the additional costs. In addition, changes in market structure create a lot of uncertainty for market actors, and should therefore be accompanied by a sufficiently long transition period. This is relevant both in the transition from national to international markets, and from the current ambition level to a higher one. In conclusion, decisions on future directions of EU RES-E support systems should be taken soon.

These considerations lead to the following recommendations.
- National governments should *coordinate* their renewable electricity policies in the light of the Renewables Directive targets. They should provide long-term clarity to market actors on their ambition levels and on the prospects for international trade and harmonisation.
- In this respect, it is also recommended to start setting *targets beyond 2010* to ensure a continued market for renewable electricity and to provide investor security.
- Given the conclusion that international trade is probably the most cost effective way of achieving the targets, national governments should look for ways to *facilitate trade* in the current fragmented market. One way could be to use the Guarantees of Origin that are to be established anyway. These could provide a basis for trade among different support schemes.
- Measures must be taken to *reduce implementation barriers* currently causing lead times of several years, thereby increasing the amount of renewable capacity that can be installed in the short run.
- Given the fact that the targets are expressed as a share of consumption, it is stressed that *Demand Side Management* can help achieving renewables targets at acceptable costs.

10.5 Further research

The ADMIRE REBUS model has been designed to support policy makers in developing and evaluating renewable electricity policy and to supports investors and other market actors in identifying market opportunities and analysing price developments. The material provided in this report is a selection of the results available to date. More detailed analyses can be made, for instance focusing on comparing different policy strategies for individual countries, as illustrated in the country case studies. Notably, the following issues would need further elaboration.

- The effects of the introduction of an emission trading system on the market opportunities, costs and deployment of renewables.
- The impact of the increased market size with the accession of 10 new Member States.
- A further analysis of the cost effectiveness of different policy instruments.
- A monitoring of the progress of Member States' efforts towards achieving their targets, including the effects of bilateral trading arrangements.

REFERENCES

BlueAge (200): *Blue Energy for A Green Europe*, 2000, Altener project.

Boston Consulting (2003): *Keeping The Lights On - Navigating Choices in European Power Generation*. Boston, May 2003.

(COM (97) 599): 1997 *White Paper on renewable energy sources* (COM (97) 599) and endorsed by the Energy Council in May 1998.

Daniëls, B.W., M.A. Uyterlinde, M. de Noord, K. Skytte, P. Meibom, M. Gual, P. del Rio, T. Hoffmann, M. Stronzik, D. Lescot (2003): *Modelling EU Renewable Energy Policies And Potentials, Methodology And Data Collection In The ADMIRE REBUS Project*, ECN-C--03-080, October 2003, Petten, The Netherlands.

Directive 2001/77/EC, 27 September 2001, on the Promotion of Electricity produced from Renewable Energy Sources in the internal electricity market.

Directive 85/337/CEE, 27 June 1985, on environmental impact assessment of some private and public projects

Doyle, J.S. (2001): *Onshore wind energy in the UK, the Netherlands, and Germany: Comparison of Planning Policy and Procedures for Grid Connected Projects*, Oxford University, September 2001.

Elkraft System et al (2001): *Balmorel: A Model for Analyses of the Electricity and CHP Markets in the Baltic Sea Region*, Downloadable from Internet: www.balmorel.dk.

EnEffect (2003): *Background paper-Central and Eastern Europe*, paper prepared for the REEEP meeting in Hungary, 3-4 July 2003, available on Internet: www.reeep.org.

ENER-IURE Project, 15 reports on planning measures.

ESHA (2000): *BlueAge, Strategic study for the development of Small Hydro Power in the European Union*, European Small Hydropower Association, 2000.

EurObserv'ER (2001): *Barometer on renewable energy sources*.

European Commission (1999): *European Union Energy Outlook to 2020*, Brussels, 1999.

Faber et al (2001): *Promotion strategies for electricity from renewable energy sources in EU countries*, Institute of Energy Economics, Vienna University of Technology, June 2001.

Gutschner, M. (2002): *Potential for building integrated photovoltaics*, IEA Photovoltaic Power Systems Programme T7-04, July 2002 (Summary).

Haas, R., Huber, C. and Wohlgemuth, N. (2001): *Financial Incentives to Promotion Renewable Energy Systems in European Electricity Markets - A Survey*, International Journal of Global Energy Issues, 2001.

Huber et al (2001): *Final Report of the project ElGreen - Organising a Joint European Green Electricity Market*. Institute of Energy Economics, Vienna University of Technology, November 2001.

IEA Bioenergy (2002): *Sustainable Production of Woody Biomass for Energy*, a position paper prepared by IEA Bioenergy, 2002.

IEA statistics (2002): *Energy prices and taxes*, 2002.

International Geothermal Association, IGA (2002): Internet: http://iga.igg.cnr.it/electricitygerneration.php, November 2002.

Jensen, P.H. et al. (2002): *Økonomi for vindmøller i Danmark* (in Danish), Risø-R-1247(DA), Risø National Laboratory, Roskilde, Denmark.

Jensen, S., and Skytte, K. (2002): *Interactions between the power and green certificate markets.* Energy Policy, Vol. 30 (5), pp. 425-435.

Jensen, S., and Skytte, K. (2003): *Simultaneous attainment of energy goals by means of green certificates and emission permits.* Energy Policy, Vol. 31 (1), pp. 63-71.

Jensen, S.G. (2002): *Quantitative analysis of technology development within renewable RES-E*, working paper, Risoe National Laboratory.

K. Skytte, P. Meibom, M.A. Uyterlinde, D. Lescot, T. Hoffmann, P. del Rio, (2003): *Challenges for investment in renewable electricity in the European Union* - Background report in the ADMIRE REBUS project, ECN-C--03-081, Petten, the Netherlands.

Madlener, R., Kaufmann, M. (2002): *Power exchange spot market trading in Europe: theoretical considerations and empirical evidence*, OSCOGEN, Deliverable 5.1b, Downloadable from www.oscogen.ethz.ch.

Mannaerts, H. and M. Mulder (2003): *Emissions trading and the European electricity market*, 7 January 2003, CPB Netherlands' Bureau for Economic Policy Analysis.

Ministère de l'aménagement du territoire et de l'évaluation environnementale (2002): *Rapport du groupe de travail sur la simplification des procédures applicables aux producteurs d'électricité à partir de sources d'énergies renouvelables*, France, 03/04/2002.

Noord, M. de et al (2003): *Potentials and costs for renewable electricity generation*, ECN-C--03-006, to be published.

Redlinger, R.Y., Andersen, P.D., Morthorst, P.E. (2002): *Wind Energy in the 21st century - Economics, Policy, Technology and the Changing Electricity Industry*, UNEP, Palgrave, New York.

Sambeek, E.J.W. van, Thuijl, E. van (2003): *The Dutch renewable electricity market in 2003; An overview and evaluation of current changes in renewable electricity policy in the Netherlands*, ECN-C--03-037, Petten, the Netherlands.

Schaeffer, G.J., Boots, M.G., Mitchell, C., Timpe, C., Cames, M., Anderson, T. (2000): *Options for design of tradable green certificate systems*, ECN-C--00-032. Petten, March 2000.

Scheepers, M.J.J.; Wals, A.F.; Rijkers, F.A.M. (2003): *Position of Large Power Producers in Electricity Markets of North Western Europe*; Report for the Dutch Energy Council on the Electricity Markets in Belgium, France, Germany and The Netherlands. ECN-C--03-003, April 2003, Petten, the Netherlands.

Smith, A. et al (2001): *Waste management options and climate change*, Report on behalf of the European Commission, DG Environment, ED21158R4.1, AEA Technology, July 2001.

Vogstad, K. et al (2001): *Integrasjon av vindkraft i det norske kraftsystemet* (in Norwegian), TR A5447, EBL-K 32-2001, SINTEF, Norway.

Voogt, M.H., Uyterlinde, M.A., de Noord, M., Skytte, K., Nielsen, L.H., Leonardi, M., Whiteley, M., Chapman, M. (2001): *Renewable energy burden sharing - REBUS - Effects of burden sharing and certificate trade on the renewable electricity market in Europe*, ECN-C--01-030, Petten, the Netherlands.

White, S., J. Green, V. Bürger, N.H. van der Linden, G. Prieto Yerro (2003): *RE-GO Analysis of Progress of Member States in Implementing a System of Guarantee of Origin* - Final Draft, IT Power, Chineham, UK, October 2003.

World Energy Council (2001): *Survey of Energy Resources 2001*, WEC, 2001.

World Hydro Atlas (2002): *The World Atlas & Industry Guide,* The International Journal on Hydro Power & Dams, 2002.

ANNEX A: THE POLICY DATA VERIFICATION PROCESS

As part of the development of an updated Data Base about policy incentives to promote the use of Renewable Energy Sources in EU countries (plus Norway), we have designed a feedback process with the main RES public institutions and bureaux in each Member State.

With the aim to verify the data on the policy schemes database, experts in renewable energy around Europe have been contacted. Therefore, this process entails a double purpose:

- Review the country data for RES policy incentives within your country.
- Give an indication of the expected policy incentives development in the medium and long-run in your country.

The data review is necessary to assure that the ADMIRE-REBUS model is fed with the most 'real' and homogenous possible data set. On the other hand, the experts view on future policy incentives development within his/her country is of vital importance to us, since it will provide a base for the design of plausible simulations with the ADMIRE-REBUS model.

The methodology used involves contacting the experts and asking feedback from them. In the review phase the expert is requested to go through two files. One (excel file) is the policy database for the corresponding country/expert. The second file (in word) contains a letter explaining ADMIRE REBUS objectives and asking for a comment on the expected evolution of renewable energy policy schemes in the respective country (see Annex).

Since it takes some time for the expert to read, review and answer the database for its country and to comment on the possible evolution of promotion schemes, it was initially considered to simply send the questionnaire through e-mail and wait for its return. However, experience with this type of activities has shown us that it is better to have a previous personal contact with the targeted person by calling him/her by phone and, then, in case he/she agreed to respond (and could do so), to send both items through e-mail. This combination of e-mail and phone is deemed more suitable than simply using either of the two methods.

Identification of experts

Experts can be grouped in two main categories: those belonging to a country that has a partner participating in ADMRE-REBUS and those that not. In the former case, the research partner was asked to send both files to the adequate person or to take responsibility for correct data collection. In order to identify the right person in non-partner countries, some databases were consulted (such as AGORES, EUREC). In other cases, consultation with Spanish firms collaborating with foreign companies revealed who could be someone suitable for consultation. In some cases where we had some doubts that we had identified the right person or that he/she was going to take the necessary time to answer, two different experts were contacted.

Country	Contact details
Austria	Energieverwertungsagentur-E.V.A.
Belgium	• CwaPE • Institut Wallon • Flemish Ministry of Mobility, Public Works and Energy
Denmark	PARTNER COUNTRY
Finland	Tekes
France	PARTNER COUNTRY
Germany	PARTNER COUNTRY
Greece	CRES

Country	Contact details
Ireland	University College Dublin Energy Research Group
Italy	PARTNER COUNTRY
Luxembourg	Some information provided by Institut Wallon
Netherlands	PARTNER COUNTRY
Norway	Institute for Energy Technology (IFE)
Portugal	Universidade Nova de Lisboa Facultade de Ciencias e Tecnología
Spain	PARTNER COUNTRY
Sweden	Swedish Energy Agency Renewable energy sources Department
U.K.	Centre for Renewable Energy Systems Technology Loughborough University

Problems encountered after contact was made

By taking a look at the rate of feedback from the experts contacted, we can observe that the success has been low. We have had problems finding the ‘right persons’ (such as in Greece and Finland). Even when experts were identified and contacted, sometimes they had no time for answering or felt they were not the right experts (in this case, they proposed someone else, with the subsequent delay this involves). In Belgium three people were contacted, each per region (Wallonia, Flanders and Brussels).

ANNEX B: STATISTICAL INDICATORS OF SENSITIVITY RESULTS

Table B.1 *Statistical indicators of simulated sensitivity results; Scenario: Continuation of Present Policies*

Year	Range	5% quantile	25% quantile	Median	Mean	75% quantile	95% quantile	Standard Deviation
	Total Costs (in mln. €)							
2000	1,964.53	232.32	650.66	916.47	948.69	1,275.77	1,687.83	425.02
2001	4,125.86	765.73	1,646.33	2,254.34	2,322.47	3,036.54	3,851.11	925.59
2002	6,231.53	1,801.51	3,009.53	3,734.11	3,917.93	4,930.68	6,060.15	1,271.11
2003	6,199.41	1,785.30	3,265.90	4,132.40	4,186.67	5,284.40	6,225.42	1,310.28
2004	7,436.44	1,924.02	3,496.70	4,883.30	4,917.88	6,330.70	7,739.32	1,744.53
2005	7,938.70	2,344.25	4,140.19	5,758.79	5,576.86	7,006.51	8,230.92	1,737.35
2006	8,648.49	2,570.27	4,424.16	6,208.76	6,058.73	7,521.20	8,934.95	1,899.71
2007	8,962.03	2,641.84	4,695.51	6,903.57	6,402.70	7,939.38	9,041.69	1,995.17
2008	10,361.97	2,845.39	5,139.22	7,597.25	6,997.38	8,725.23	9,861.12	2,244.05
2009	10,886.13	2,757.68	5,647.51	8,089.45	7,381.59	9,039.47	10,357.88	2,337.21
2010	11,961.11	3,156.05	6,074.55	8,657.95	8,023.76	9,949.33	11,447.17	2,599.57
2011	10,922.07	3,397.37	6,450.15	8,323.68	7,708.09	9,143.71	10,611.27	2,206.28
2012	12,876.50	3,485.17	6,836.02	8,353.06	7,855.06	9,212.54	10,927.85	2,215.14
2013	14,933.22	3,546.67	7,091.74	8,610.52	8,152.50	9,405.21	11,159.94	2,330.78
2014	15,864.59	3,680.38	7,268.97	8,666.69	8,446.13	9,797.65	12,437.46	2,555.76
2015	16,453.39	3,876.02	7,502.90	8,629.35	8,756.19	10,054.75	14,170.81	2,819.12
2017	21,643.47	4,429.52	8,426.77	9,904.98	10,690.93	12,392.93	19,543.17	4,206.06
2020	26,325.26	5,884.28	9,454.81	11,918.16	13,613.63	18,317.72	23,996.63	5,897.54
2025	37,194.35	7,295.20	11,591.80	15,491.72	18,409.90	25,966.13	30,883.53	8,253.27
2030	40,674.21	7,759.70	12,355.43	19,592.77	19,478.62	27,047.04	30,912.25	8,217.04
	Realisations (in GWh)							
2000	17,394.50	346,258.80	349,596.30	351,692.00	352,350.40	355,224.80	359,297.60	3,898.56
2001	54,731.72	348,129.00	357,595.80	366,283.40	368,127.50	378,130.60	391,357.40	13,112.22
2002	101,201.40	351,950.00	368,607.90	383,975.00	387,900.50	406,494.80	429,118.60	24,124.37
2003	135,789.10	355,653.30	378,581.80	400,933.80	405,016.00	429,234.10	460,470.30	32,402.69
2004	172,572.50	359,294.30	386,641.80	418,617.40	422,837.90	454,192.60	495,464.50	41,925.97
2005	202,962.20	363,461.30	394,318.90	437,926.90	439,890.70	477,157.40	526,288.80	50,153.66
2006	233,768.50	367,203.60	404,404.60	454,154.80	455,727.70	498,670.70	553,426.20	58,083.51
2007	269,340.60	370,371.20	413,241.80	471,461.00	472,507.60	522,613.50	584,940.60	67,256.63
2008	306,619.20	373,614.40	423,425.90	490,140.70	489,532.40	548,336.30	616,316.30	76,346.18
2009	339,872.30	376,987.80	434,635.10	507,050.80	504,364.00	568,293.30	643,675.10	83,705.49
2010	366,642.10	381,494.70	446,540.10	522,228.80	519,455.70	586,129.50	671,544.00	90,036.40
2011	391,845.40	383,340.50	455,411.00	527,718.00	529,768.90	598,668.90	689,887.10	94,268.74
2012	418,871.40	385,634.50	464,751.30	533,072.80	539,092.30	610,501.30	705,108.80	98,222.57
2013	455,531.20	386,041.70	472,569.00	539,095.80	547,617.40	622,031.80	719,290.30	102,802.30
2014	500,461.90	384,913.70	480,503.60	546,301.30	555,296.10	632,558.70	733,413.60	108,540.30
2015	537,565.90	385,683.30	483,073.00	553,900.30	563,338.50	647,309.90	760,462.40	115,326.80
2017	597,049.90	390,634.00	489,959.80	568,589.30	583,149.60	675,657.60	824,684.20	131,859.00
2020	645,198.60	400,141.70	503,671.00	581,294.20	618,628.00	746,217.30	906,319.50	157,275.10
2025	709,869.00	411,753.70	522,124.70	621,053.90	674,427.60	855,854.20	964,904.40	187,486.80
2030	843,176.00	429,218.80	542,513.30	719,792.90	718,847.40	888,793.80	1,039,585.00	203,732.50
	Relative Compliance (in % of target)							
2000	4.75	94.48	95.39	95.96	96.14	96.93	98.04	1.06
2001	13.92	88.54	90.95	93.16	93.63	96.18	99.54	3.34
2002	24.06	83.66	87.62	91.28	92.21	96.63	102.01	5.73
2003	30.24	79.21	84.32	89.30	90.20	95.60	102.56	7.22
2004	36.09	75.14	80.86	87.55	88.43	94.99	103.62	8.77
2005	39.94	71.53	77.61	86.19	86.57	93.91	103.58	9.87
2006	43.50	68.33	75.25	84.51	84.80	92.80	102.98	10.81
2007	47.47	65.27	72.83	83.09	83.27	92.10	103.08	11.85
2008	51.25	62.45	70.77	81.93	81.82	91.65	103.02	12.76
2009	53.96	59.85	69.00	80.50	80.07	90.22	102.19	13.29
2010	55.36	57.61	67.43	78.86	78.44	88.51	101.40	13.60
2011	58.05	56.79	67.46	78.17	78.48	88.69	102.20	13.96
2012	60.90	56.06	67.57	77.50	78.37	88.76	102.51	14.28
2013	65.02	55.10	67.45	76.94	78.16	88.78	102.66	14.67
2014	70.15	53.95	67.35	76.57	77.83	88.66	102.80	15.21
2015	74.02	53.11	66.52	76.27	77.57	89.13	104.71	15.88
2017	80.23	52.49	65.84	76.41	78.36	90.79	110.82	17.72
2020	83.67	51.89	65.32	75.39	80.23	96.78	117.54	20.40
2025	86.02	49.89	63.27	75.25	81.72	103.71	116.92	22.72
2030	96.07	48.90	61.81	82.01	81.90	101.27	118.45	23.21

Table B.2 *Statistical indicators of simulated sensitivity results; Scenario: Trade & harmonisation 2007-2012*

Year	Range	5% quantile	25% quantile	Median	Mean	75% quantile	95% quantile	Standard Deviation
	Total Costs (in mln. €)							
2000	1,964.59	231.04	650.76	916.06	948.85	1,276.07	1,691.47	425.49
2001	4,128.57	766.46	1,646.17	2,244.34	2,322.85	3,039.57	3,850.70	926.47
2002	6,046.03	1,807.27	3,012.23	3,747.75	3,918.37	4,943.73	5,969.79	1,263.43
2003	6,213.78	1,818.12	3,264.77	4,142.11	4,187.40	5,268.43	6,253.21	1,310.89
2004	7,466.13	1,926.59	3,492.03	4,875.28	4,925.61	6,355.17	7,777.97	1,756.32
2005	7,951.38	2,374.93	4,136.68	5,767.07	5,584.36	7,017.18	8,246.28	1,739.02
2006	8,653.36	2,578.31	4,468.20	6,191.19	6,073.68	7,552.53	8,954.02	1,894.96
2007	7,480.88	3,565.73	4,589.33	6,399.05	6,445.27	8,100.44	9,992.04	2,064.43
2008	16,115.62	8,898.47	10,466.94	13,073.76	13,647.37	16,453.75	20,031.81	3,644.14
2009	20,656.99	10,492.05	14,168.86	18,165.56	17,990.03	21,948.86	25,776.66	4,962.33
2010	24,396.65	11,301.19	16,789.07	21,528.44	21,039.47	25,648.24	29,717.57	5,879.32
2011	28,165.54	12,114.94	19,739.85	25,441.61	24,247.10	29,294.99	33,184.88	6,652.16
2012	31,514.69	13,238.45	23,346.27	28,743.28	27,549.67	33,440.98	36,795.49	7,209.44
2013	32,735.09	12,947.76	14,325.42	19,927.69	22,723.38	31,017.74	37,633.64	8,959.20
2014	33,964.19	13,003.05	13,959.19	17,294.88	20,479.14	24,047.10	38,315.63	8,538.76
2015	34,988.87	13,150.26	14,282.65	16,907.37	19,504.79	21,252.99	38,544.61	7,522.78
2017	37,701.24	12,539.72	15,055.42	16,499.56	18,477.12	19,687.38	33,039.90	6,219.14
2020	40,908.69	13,730.77	17,072.46	19,343.59	19,826.26	21,141.97	31,950.84	5,208.73
2025	44,872.39	19,033.82	21,524.71	25,589.25	26,032.32	29,626.21	34,572.63	5,995.87
2030	53,058.58	19,766.55	24,306.32	27,941.22	28,151.92	31,257.89	36,386.06	6,439.59
	Realisations (in GWh)							
2000	17,307.91	346,331.30	349,701.80	351,857.80	352,472.70	355,340.70	359,297.60	3,871.32
2001	54,719.22	348,231.00	357,762.60	366,664.80	368,376.20	378,879.00	391,448.00	13,108.50
2002	101,287.90	352,220.10	369,018.70	384,931.70	388,380.70	406,961.20	429,296.10	24,162.00
2003	135,881.40	356,026.30	378,495.60	401,495.20	405,441.50	430,442.30	460,812.10	32,450.77
2004	173,226.40	359,763.40	386,742.20	419,843.50	423,677.80	455,266.50	495,896.00	41,860.76
2005	203,270.80	364,014.40	396,811.10	438,575.60	440,896.90	478,238.00	526,663.60	49,830.66
2006	234,887.50	367,770.70	404,870.50	455,788.20	456,926.50	498,951.30	554,138.50	57,546.03
2007	258,371.50	370,085.00	416,429.30	466,899.80	467,779.90	512,669.80	569,435.50	59,157.84
2008	286,048.90	379,798.80	448,850.80	502,363.30	496,337.00	540,754.50	589,435.10	60,792.72
2009	311,765.10	393,054.30	485,633.00	542,327.00	527,863.20	576,235.70	612,922.10	64,371.35
2010	328,700.50	408,062.90	523,203.20	583,102.70	561,283.90	613,202.70	641,782.50	68,976.45
2011	361,387.90	423,099.80	562,333.40	626,697.80	596,372.60	650,710.70	664,449.70	73,595.55
2012	384,150.60	436,848.90	609,254.40	672,803.90	634,434.60	688,266.00	689,566.40	78,682.01
2013	398,931.90	451,588.40	660,171.50	701,366.30	662,463.80	702,403.90	703,869.80	78,794.81
2014	408,216.60	468,198.40	706,055.30	714,569.60	682,202.50	714,945.60	716,437.00	78,236.40
2015	416,046.30	486,921.50	726,560.80	727,131.00	698,399.40	727,334.90	728,462.80	77,816.90
2017	432,867.40	525,428.80	744,750.60	745,018.20	720,913.00	745,267.90	746,888.30	75,268.85
2020	461,259.50	584,255.00	771,398.50	771,720.30	751,309.40	772,159.40	777,275.30	72,096.01
2025	561,092.40	666,824.80	825,468.60	825,873.80	807,990.10	826,563.00	827,990.30	71,905.21
2030	616338.90	743136.50	877703.10	877929.80	862015.30	878636.30	884033.50	73536.41
	Relative Compliance (in % of target)							
2000	4.72	94.50	95.42	96.01	96.18	96.96	98.04	1.06
2001	13.92	88.57	91.00	93.26	93.69	96.37	99.56	3.33
2002	24.08	83.73	87.72	91.50	92.32	96.74	102.05	5.74
2003	30.26	79.29	84.30	89.42	90.30	95.87	102.63	7.23
2004	36.23	75.24	80.88	87.81	88.61	95.22	103.71	8.75
2005	40.01	71.64	78.10	86.32	86.77	94.12	103.65	9.81
2006	43.71	68.44	75.34	84.82	85.03	92.85	103.12	10.71
2007	45.53	65.22	73.39	82.28	82.44	90.35	100.35	10.43
2008	47.81	63.48	75.02	83.97	82.96	90.39	98.52	10.16
2009	49.50	62.40	77.10	86.10	83.80	91.48	97.31	10.22
2010	49.63	61.62	79.00	88.05	84.75	92.59	96.91	10.42
2011	53.54	62.68	83.30	92.84	88.35	96.39	98.43	10.90
2012	55.85	63.51	88.57	97.81	92.24	100.06	100.25	11.44
2013	56.94	64.45	94.22	100.10	94.55	100.25	100.46	11.25
2014	57.22	65.63	98.97	100.16	95.62	100.21	100.42	10.97
2015	57.29	67.05	100.05	100.12	96.17	100.15	100.31	10.72
2017	58.17	70.61	100.08	100.11	96.87	100.15	100.37	10.11
2020	59.82	75.77	100.04	100.08	97.44	100.14	100.80	9.35
2025	67.99	80.80	100.02	100.07	97.91	100.16	100.33	8.71
2030	70.22	84.67	100.00	100.03	98.21	100.11	100.72	8.38

Table B.3 *Statistical indicators for the equilibrium price; Scenario: Trade & Harmonisation 2007-2012*

Year	Range	5% quantile	25% quantile	Median	Mean	75% quantile	95% quantile	Standard Deviation
	Equilibrium Price (in €c/kWh)							
2007	7.42	1.71	1.92	2.58	2.48	2.76	3.33	0.63
2008	7.39	2.76	3.25	6.72	6.26	8.91	8.91	2.63
2009	7.45	2.84	4.67	8.91	7.12	8.91	8.91	2.37
2010	7.36	2.76	5.37	8.91	7.34	8.91	8.91	2.21
2011	7.57	2.90	6.10	8.91	7.50	8.91	8.91	2.04
2012	7.50	3.96	6.18	8.91	7.60	8.91	8.91	1.84
2013	7.57	2.80	3.38	5.22	5.92	8.91	8.91	2.59
2014	7.55	2.77	2.98	3.86	5.10	8.91	8.91	2.52
2015	7.50	2.75	2.98	3.69	4.67	5.22	8.91	2.30
2017	7.39	2.53	2.89	3.08	4.04	4.02	8.91	2.07
2020	7.50	2.48	2.95	3.52	3.90	3.73	8.91	1.79
2025	6.43	3.14	3.35	3.62	4.21	4.44	8.91	1.56
2030	7.28	2.95	3.40	3.83	4.05	4.11	8.91	1.50

Table B.4 *Regression results of scenarios Continuation of Present Policies and Trade & Harmonisation 2007-2012*

Harmonisation & Trade 2007-2012

	coefficient	*std. error*	*t*	*P>|t|*	*95% conf. Interval*	
	Total Expenditures					
Pipeline success rate	-1,275.13	218.37	-5.84	0.00	-1,703.32	-846.94
Max. growth rate of technologies	34.52	211.41	0.16	0.87	-380.02	449.07
Lead times	357.82	220.04	1.63	0.10	-73.63	789.28
Max. growth rate of resources	15.70	219.01	0.07	0.94	-413.73	445.13
Reference price	1,829.46	217.23	8.42	0.00	2,255.41	1,403.51
Period	866.37	10.00	86.66	0.00	846.77	885.97
Constant	6,975.03	570.75	12.22	0.00	5,855.90	8,094.17
	Realisations					
Pipeline success rate	51,448.05	2,626.15	19.59	0.00	46,298.65	56,597.45
Max. growth rate of technologies	4,016.86	2,262.06	1.78	0.08	-418.62	8,452.35
Lead times	2,706.56	2,176.10	1.24	0.21	-1,560.38	6,973.49
Max. growth rate of resources	16,598.01	2,075.78	8.00	0.00	12,527.79	20,668.23
Reference price	21,089.27	2,239.26	9.42	0.00	25,480.05	16,698.50
Period	17,520.28	112.99	155.06	0.00	17,298.73	17,741.83
Constant	322,103.60	6,555.29	49.14	0.00	309,249.90	334,957.30
	Relative Compliance					
Pipeline success rate	7.41	0.36	20.61	0.00	6.70	8.11
Max. growth rate of technologies	0.55	0.30	1.83	0.07	-0.04	1.14
Lead times	0.30	0.29	1.04	0.30	-0.27	0.88
Max. growth rate of resources	2.43	0.29	8.46	0.00	1.87	3.00
Reference price	3.57	0.31	11.37	0.00	4.19	2.95
Period	0.29	0.02	19.35	0.00	0.26	0.32
Constant	82.30	0.94	87.14	0.00	80.45	84.15
	Equilibrium Price					
Pipeline success rate	-2.09	0.04	-47.19	0.00	-2.18	-2.00
Max. growth rate of technologies	-0.08	0.05	-1.71	0.09	-0.17	0.01
Lead times	0.20	0.05	4.20	0.00	0.11	0.30
Max. growth rate of resources	-1.01	0.05	-22.11	0.00	-1.10	-0.92
Reference price	-1.16	0.05	24.04	0.00	-1.06	-1.25
Period	-0.17	0.00	-41.05	0.00	-0.18	-0.16
Constant	10.20	0.12	86.42	0.00	9.97	10.43

Continuation of Present Policies

	coefficient	*std. error*	*t*	*P>|t|*	*95% conf. Interval*	
	Total Expenditures					
Pipeline success rate	2,345.71	131.47	17.84	0.00	2,087.93	2,603.49
Max. growth rate of technologies	142.27	130.79	1.09	0.28	-114.19	398.72
Lead times	121.46	128.60	0.94	0.35	-130.69	373.62
Max. growth rate of resources	672.70	126.10	5.33	0.00	425.45	919.95
Reference price	5,672.79	138.94	40.83	0.00	5,945.23	5,400.35
Period	620.33	8.33	74.46	0.00	603.99	636.66
Constant	3,673.68	344.47	10.66	0.00	2,998.24	4,349.11
	Realisations					
Pipeline success rate	65,999.81	3,002.49	21.98	0.00	60,112.49	71,887.13
Max. growth rate of technologies	4,654.52	2,836.41	1.64	0.10	-907.16	10,216.19
Lead times	-2,327.53	2,826.00	-0.82	0.41	-7,868.78	3,213.72
Max. growth rate of resources	25,594.24	2,771.57	9.23	0.00	20,159.71	31,028.77
Reference price	164,755.60	3,279.90	50.23	0.00	171,186.90	158,324.40
Period	11,912.41	193.14	61.68	0.00	11,533.70	12,291.12
Constant	444,421.10	8,233.91	53.97	0.00	428,275.90	460,566.20
	Relative Complaiance					
Pipeline success rate	9.14	0.39	23.38	0.00	8.37	9.90
Max. growth rate of technologies	0.62	0.37	1.69	0.09	-0.10	1.33
Lead times	-0.39	0.37	-1.06	0.29	-1.10	0.33
Max. growth rate of resources	3.56	0.36	9.90	0.00	2.86	4.27
Reference price	21.56	0.42	51.88	0.00	22.38	20.75
Period	-0.36	0.02	-15.16	0.00	-0.41	-0.31
Constant	96.89	1.08	89.40	0.00	94.76	99.01