north
european
power
perspectives

Energy Policy and Electricity System Development

- in Sweden, the Nordic countries and Europe

NEPP report

January 2014, and December 2015

Energy Policy and Electricity System Development

- in Sweden, the Nordic countries and Europe

January 2014, and December 2015

Thomas Unger, Profu

Bo Rydén, Profu

Håkan Sköldberg, Profu

Mikael Odenberger, Chalmers

Filip Johnsson, Chalmers

Lisa Göransson, Chalmers

Table of Content

Preface 6

Summary and introduction 7

Overall insights 8

15 conclusions about the development of the electricity system 9

Energy and climate policy in Europe – current status 11

EU energy and climate policy 12

The year 2020 energy and climate package 12

The year 2030 framework 12

The Roadmap 2050 13

Current status and projections of the GHG reduction target 13

Factors behind the reduction of greenhouse gases between 1990 and 2012 15

The newest Member States have reduced their emissions of GHGs more than the old ones (EU15) 16

Important policies in GHG emission reductions 17

The EU ETS – a key instrument to reduce GHG emissions 18

Recent development in the EU ETS market 18

Existing imbalance in the ETS market 19

The market stability reserve 21

Recent fossil-fuel price development and its impact on electricity generation 21

The renewable energy directive (RED) – increasing the share of renewables across Europe 22

The rapid development of renewable electricity generation – the German case 25

The common Swedish-Norwegian electricity-certificate scheme 25

Recent cost developments in wind and solar power generation 26

The energy efficiency directive – the goal to increase efficiency and save energy 28

European energy and climate policy: a single common framework or a regionalised patchwork of frameworks? 29

The existing European power plant capacity: investments in renewables and aging thermal power plants 31

The Large Combustion Plant Directive (LCPD) 33

Status and prospects of CCS 35

Nuclear power 36

A controversial technology 37

The European nuclear power plant fleet 37

Costs of nuclear power 39

GDP as a driving force for GHG emissions and energy consumption 41

GDP – Its historical and future development 41
The relation between GDP development, energy use and greenhouse gas emissions 42
Energy intensity and carbon dioxide emission intensity 43
The development of energy use related to different development of GDP 44
The EU has come to the conclusion that the decline in the GDP growth is of minor significance, in spite of their own analyses pointing in the opposite direction 46
The development of greenhouse gases emissions with different GDP development 51
The target for renewables is not impacted to the same extent by the GDP development 53
Summary of the importance of the GDP development for target attainment 54
European electricity-system outlook 55
The existing generation-capacity stock 55
Key scenario assumptions 57
Scenario results - Electricity supply 59
Reference scenario 59
Regional Policy scenario 60
Climate Market scenario 61
Green Policy scenario 62
Cross-scenario comparisons 63
Electricity supply 63
Interconnector capacity 64
Capacity investments 65
Electricity prices and prices of CO_2 67
Nordic and Swedish electricity system outlook 72
The historical development 72
The electricity generation in Sweden and the Nordic countries since year 1990 72
Electricity trade between Sweden, the Nordic countries and the rest of Northern Europe 73
Electricity demand in Sweden and the Nordic countries since 1990 73
The future development of the Swedish and Nordic electricity systems 74
The Nordic electricity system is well prepared to meet the future uncertainties and challenges 74
The most significant energy system uncertainties/challenges for the electricity system are associated with capacity 75
The Swedish and Nordic electricity and heating systems are close to CO_2-free, it's better to focus on other sectors 76
The challenges and the uncertainties the electric system is facing in the rest of Europe are much tougher, and many countries have demanding transformation targets to deliver to the coming years 76

The renewable electricity is increasing, but how much renewables we will have in Sweden and the Nordic countries the next 10-15 years is determined exclusively by our own politics 78

Synthesis of our scenario results 79

What is required for a really massive expansion of renewables up to year 2030? 80

The prices of electricity will remain low in the short term (5-10 years), regardless of which of the main scenarios we look at 81

The end-user price of electricity will rise in the long perspective 82

The demand for a very large share of renewable power generation pushes down the wholesale price to low levels, which means that investments in wind and solar power need state support even with a continued strong technology development. 83

It will take a strong pan-European driving force and an adequately large differentiation in electricity prices for a large electricity export and a massive development of the transmission capacity to take place 85

Sweden will continue to be a dominating exporter as long as we have nuclear power 87

The Swedish nuclear power is maintained through reinvestments in the scenario with a high price of CO2, and phased-out in the scenarios with a large support to renewables and improved efficiency 87

We must pay more attention to the electricity capacity issue, especially for the period after 2030 89

References 92

Preface

During the course of the second phase of the NEPP project, a multitude of reports and texts have been written. This book contains texts written at two different periods in time, in 2012-2013 and in 2014-2015. The sections of the book describing European energy and climate policy were written in the first time period of the project and formed the basis of the initial model analyses that were performed during that period. The results of these model analyses are reported elsewhere. Even though somewhat out of date given the original purpose of describing a "current status", we believe that these text sections are, nevertheless, useful to the reader especially when it comes to describing the background and the rationale of the detailed model analyses that were carried out during the course of the project. These somewhat older sections of the book are specially marked – in grey in the margin - in order to alert the reader.

During the second time period of the project, additional model analyses were conducted with updated model assumptions on e.g. the 2030 climate and energy framework of the EU. These model results are reported in the present book. Furthermore, analyses of the driving factors behind greenhouse-gas emission reductions and the link between economic growth and energy demand were also conducted during the later phase of the project and are also included in the present book.

Summary and introduction

The Nordic and European Energy systems are facing considerable challenges. Some examples are:

- Significant reduction of carbon dioxide emissions, increasing the share of renewable energy, reducing the energy demand and at the same time supporting the economic growth without tilting the competition with the surrounding world.
- Securing the development of new production and removing obstacles impeding investments in new infrastructure in the energy sector.
- Improving the efficiency of the electricity market and continuing the integration of Europe's electricity systems.
- Securing the energy supply and continuing reducing the dependence on fossil energy.

In the coming few years, there are a lot of decisions to be made within the energy and climate areas regarding the direction of the energy politics, the design of policy instruments and regulatory frameworks, and about new investments in the energy infrastructure. These issues are to a large extent dealt with at an international level, e.g. in EU or in agreements between individual states, but national political decisions will also play an important role. It is of uttermost importance that politicians, authorities, energy enterprises and actors on the market possess a deep insight into the expected development and about the consequences of the decisions they take. A basic understanding of the electricity market and the development of the electricity systems is a prerequisite for the decisions that are taken to be well balanced and adequately effective. This underpins the need for a comprehensive knowledge uplift with a holistic view of the future development of the electricity systems in Sweden, the Nordic countries and Europe.

The European Union (EU) has proposed ambitious energy and climate policy goals to meet the criteria for a sustainable energy future. By year 2020, greenhouse-gas (GHG) emissions are to be reduced by 20% relative to the emission levels in year 1990, the share of renewable energy should be 20% of total gross consumption, and the use of primary energy should be reduced by 20% relative to a baseline projection (EC, 2007).[1] The target for the reduction of GHG emissions has been transformed into a common European cap-and-trade scheme, the EU Emissions Trading Scheme (EU ETS), as well as separate national targets for the non- tradable sectors, which include transportation, buildings, the commercial sector, and parts of the industrial sector. In addition, the renewable energy target has largely been converted into national legislation across the Member States (MS). The next milestone of the EU energy and climate policy package is year 2030 when GHG emissions are to be reduced by 40%, as compared with the level in year 1990, the share of renewable energy should reach 27% of gross consumption, and the use of primary energy is to be reduced by 27% relative to a baseline projection (EC, 2014).[2] The renewable target is binding at the EU level but not at Member State level. The efficiency target is subject to review in 2020. The final milestone year in the current EU policy setup is 2050 as expressed in the EU Roadmap 2050 (EC, 2011)[3]. Hitherto, only targets for reducing GHG emissions have been expressed for that time frame. Subsequently, GHG emissions in the EU are to be reduced domestically by at least 80% by year 2050 (relative to the corresponding levels of emissions in year 1990).

---

[1] European Commission, COM(2007) 723 final

[2] European Council, 2014, EUCO 169/14, http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/145397.pdf

[3] European Commission, 2011, "A Roadmap for moving to a competitive low carbon economy in 2050", COM(2011) 112 final

Model analyses initiated by the European Commission to assess the impact of the targets expressed in the EU Energy and Climate Roadmap 2050 indicate that with respect to reducing CO_2 emissions, the European electricity supply system has certain comparative advantages over other sectors, such as industry. The reasons for this include the multitude of technologies available to generate electricity and heat and the fact that fuel switching (e.g. coal to gas or coal to biomass) may reduce the dependence on CO_2-intensive fuels. Consequently, emissions that emanate from the electricity supply system in the EU may have to approach zero-level to meet the above-mentioned target of 80% reduction in GHG emissions for the entire energy system (see e.g. the EU Roadmap analyses initiated by the European Commission). As we will show in this study, large-scale integration of renewable electricity generation is obviously a key option for reaching such emissions targets. However, this integration poses new challenges and requirements on other generation technologies in the supply system, on the transmission and distribution grids, and also on the end-users, to uphold the balance and interactions between supply and demand.

Overall insights

As a consequence of the stringent European energy and climate policy towards 2050, the impact of the European electricity-supply system is likely to be very significant. Assuming that policy goals are met, the European electricity-supply system will emit only a marginal fraction of the greenhouse gases emitted today and the share of renewable electricity may amount to at least half of gross electricity consumption. However, depending on the setup and degree of European harmonization of policy instruments, and depending on the technological development and availability of some technologies, e.g. nuclear power, carbon capture and storage, and renewable electricity generation, we find that the pathways towards very low emissions may differ significantly. This impacts the balance between different technologies, the total consumption of electricity, the electricity-price formation and the pace and magnitude of capacity investments over time. Nevertheless, all pathways which fulfil the 2050 climate policy goals will consist of large amounts - yet at different levels - of renewable electricity such as wind and solar power. In this study, we elaborate on these issues based on extensive and detailed modelling of the entire European electricity-supply system from today and until 2050. The most important findings and conclusions of this study include:

- Renewable electricity generation (RES-E) will grow substantially in all investigated scenarios. The difference across the scenarios lies in the investment pace. Assuming less stringent climate-policy goals will reduce the need for new renewable electricity somewhat.
- Since variable renewable electricity generation (vRES-E), with inherent lower annual capacity utilization compared to traditional thermal power plants, grows substantially in all investigated scenarios, overall installed capacity will grow much faster than the demand for electricity on an energy basis (this development has already been a fact during the last years after a long period since 1990 when capacity grew equally fast as demand in Europe as a whole). In this study, we estimate the electricity gross consumption to grow roughly between zero and 50% up to 2050, depending on scenario, compared with 2013, while the installed capacity grows between 50% and more than 100%, depending on scenario, during the same period of time.
- The transition towards more vRES capacity will involve an increased demand for regulating capacity. This includes supply options in the form of back-up during times with low availability of wind and solar irradiation, such as gas turbines, but also end-use options such as increased flexibility in electricity demand.
- The transition of the European electricity-supply system may also involve new investments in conventional high-efficient fossil-fuel based generation (e.g. natural gas power), new nuclear power (if politically acceptable) and carbon capture and storage, CCS (if commercially

available). Common to these non-renewable, yet CO_2-lean, alternatives is that price signals in the wholesale market must be adequate and reach levels that differ substantially from what currently is seen in the European wholesale electricity markets.

15 conclusions about the development of the electricity system

Our energy system analyses have generated a wide range of results and insights, from which we have compiled a set of 15 conclusions. Each and every of the conclusions is not by necessity new findings, but altogether they give a picture of the challenges and the opportunities for the future development of the electricity systems in Sweden, the Nordic countries and Europe. They also give a good summary of the consequences of different possible development paths in the world surrounding the electricity systems, and not the least what consequences to expect for the development of the electricity system from different political decisions.

1. Electricity and the electricity system play – and are expected to play – an increasingly more central role in the transformation of the energy system. The share of electricity of the energy use is also steadily growing, particularly in other parts of Europe, but some growth is also expected in the Nordic countries.
2. The Nordic electricity system is well prepared to meet the future challenges and uncertainties that come with the different development paths which are part of our energy system scenarios. If the Nordic countries want to reduce their CO_2 emissions, they should focus on other sectors. And there electrification might be a part of the solution.
3. The challenges and uncertainties for the electricity systems are much bigger in other parts of Europe, and many countries have significant commitments regarding the transformation to live up to already in the next couple of years. Examples of challenges and uncertainties in the short and in the long term are: reduction of emissions, the amount of renewables, capacity management, grid expansions, shaping the electricity market, price development for fossil fuels and the technical development, e.g. of CCS.
4. The energy and climate politics in the EU and its Member States is the factor with the largest impact on the development of the power system. The greenhouse gas goal for 2020 is already achieved, but fulfilling the commitments for renewables by 2020 is still a big challenge for many (large) European countries, not for Sweden and the Nordic countries though. The goals for 2030 will have an even more profound impact on the electricity systems, even in the Nordic countries.
5. There are significant differences in the development of the system and the policy instruments between our scenarios with one and with three goals, particularly in the long run. For instance, in a medium term perspective, 2030, the "Three goal scenario" results in an expansion of wind and solar power in the Nordic countries only half as big as the "one goal scenarios" (climate or renewables).
6. The slow GDP growth in the EU increases the possibility to reach the efficiency and greenhouse gas goals by 2020 and 2030. But. If the economic development takes speed again and we recover fully from the financial crisis, the energy and climate goals will be much harder to reach than what the current estimates say. At the same time, electricity demand will then grow faster, in the Nordic countries as well as in the EU, up to twice as fast as in the current prognosis.
7. The expectations on reductions of the carbon dioxide emissions from electricity generation on the Continent are very large in the EU's energy scenarios, and there are real opportunities

for large reductions of emissions. Since the share of electricity of the total energy use grows, it will contribute to the reduction of carbon dioxide emissions also in other sectors. Electricity will therefore play dual roles in the transformation.

8. The renewable electricity grows, but how much of renewables we will see in Sweden and the Nordic countries the next 10-15 years will be determined solely by our own politics. In the long run, after 2030, our scenarios show a demand for relatively large quantities of wind power (and even solar power), but in the short perspective, the demand is considerably smaller. Neither EU expectations, nor electricity shortage, motivate more of renewables in the short term, only the national political demands do.
9. The price of electricity will remain low in the short perspective, 5-10 years, regardless of which scenario we look at. This goes for the whole sale prices as well as the retail prices.
10. The price of electricity for end-users will rise in the long term. In scenarios with high climate ambitions the retail prices as well as the wholesale price will rise in the long run. In scenarios with high ambitions regarding renewables the wholesale price might rather decrease further, but the total price for end-users including costs for aid will rise.
11. A demand for a very large share of renewable power generation will push down the wholesale price to really low levels. Which means that investments in wind and solar power will require aid even with a continued strong technology development.
12. A strong pan-European driving force and a big enough difference in electricity prices are required to get a large export of electricity and a massive expansion of transmission capacity. The size of the Nordic electricity export is determined mainly by 1) the strength of the common European energy and climate politics, 2) the development of the electricity demand, and 3) the future of the Swedish nuclear power.
13. The Swedish nuclear power is remained through reinvestments in the scenarios with a high CO_2 price and/or a low aid to renewables, and is phased out in the scenarios with an increased aid to renewables and/or efficiency improvements. But, our sensitivity analysis shows that already rather small alterations of the assumptions regarding investment costs, nuclear power tax, electricity demand or energy/climate politics can change the outcome.
14. We must pay more attention to the electricity <u>capacity</u> issue, particularly after 2030. A growing share of renewable electricity generation will result in challenges when there is a low demand for electricity and much wind and solar power, as well as when there is a high demand for electricity and little wind and solar power. An enhanced “intelligence” in the system could bring many benefits.
15. The transmission of the European electricity system requires large yearly investments all the way up to 2050, at the same level as the historical peak years. All our scenarios show that the investments in the electricity systems on the Continent, will reach levels the coming 10-20 years, which are of the same magnitude as the historical top records, and in couple of the scenarios the investments will be even larger after 2030.

Background

Over the last century, the demand for commercial energy services, such as electricity, heat, and transport, has increased dramatically in Europe and around the world. Currently, more than 80% of all commercial energy that is used globally is sourced from fossil fuel reservoirs. Given this heavy dependence on fossil fuels, and the associated release of CO2 and other greenhouse gases (GHGs), the global community now faces serious environmental and technological challenges.

To address and mitigate the increasingly serious threat of climate change, the global society must urgently face the challenge of substantially reducing the levels of GHG emissions, especially those of CO_2. Policy-makers must develop near-term strategies to set both the European and global economies on a course towards energy sustainability. Technologies already exist or will soon become available which, if implemented on a sufficiently large scale, would make it possible to make the cuts in CO emissions that are required to maintain global warming at less than 2ºC. This is the level identified by the IPCC as being necessary to avoid catastrophic effects on ecosystems. However, reducing CO2 emissions (as well as the emissions of other GHGs) must be carried out in a way that maintains the security of supply and guarantees social and economic sustainability. The European Union (EU) has proposed ambitious energy and climate policy goals to meet the criteria for a sustainable energy future. By year 2020, GHG emissions are to be reduced by 20% relative to the emission levels in year 1990. Furthermore, by year 2020, the share of renewable energy should be 20% of total gross consumption, and the use of primary energy should be reduced by 20% relative to a baseline projection by year 2020. The target for the reduction of GHG emissions has been transformed into a common European cap-and-trade scheme, the EU Emissions Trading Scheme (EU ETS), as well as separate national targets for the non-tradable sectors, which include transportation, buildings, the commercial sector, and parts of the industrial sector. In addition, the renewable energy target has largely been converted into national legislation across the Member States. A framework for the year 2030 policy was proposed in January 2014 and is subject to ongoing discussions and analyses. Both the European Parliament and the European Commission have proposed a GHG emissions reduction target of 40%, as compared with the level in year 1990. With respect to the targets set for renewable energy and increases in efficiency or reductions in energy use, the viewpoints of the Commission and Parliament currently diverge (see more in the chapter *Setting the scene*). Looking further into the future, towards year 2050, the Commission's ambitions and policy goals are defined in the EU Energy and Climate Roadmap 2050, which was launched prior to the year 2030 framework (in year 2011) and has been used as guidance for the year 2030 framework. Subsequently, GHG emissions in the EU are to be reduced domestically by at least 80% by year 2050 (relative to the corresponding levels of emissions in year 1990).

Model analyses initiated by the European Commission to assess the impacts of the targets expressed in the EU Energy and Climate Roadmap 2050 indicate that with respect to reducing CO2 emissions, the European electricity supply system has certain advantages over other sectors, such as industry. Consequently, emissions that emanate from the electricity supply system in the EU may have to approach zero-level to meet the above-mentioned target of 80% reduction in GHG emissions for the entire energy system. Large-scale integration of renewable electricity generation is obviously a key option for reaching the emissions targets. However, such integration poses new challenges and imposes requirements on other generation technologies in the supply system, on the transmission and distribution grids, and also on the end-users, to uphold the balance and interactions between supply and demand.

Energy and climate policy in Europe – current status

This main section describes the background which has motivated the research that is reported in this book. We describe and discuss the EU energy and climate policies, which constitutes and defines the largest share of the research presented here. These policies include goals and means for greenhouse-gas emission reductions, renewable energy and energy use. We also reflect upon some of the numerous challenges that we face in achieving our ambitions to transform our energy systems to *having a significantly higher level of sustainability, including the controversies and uncertainties related to some key technologies, such as nuclear power and CCS. We also briefly report on current trends and discuss some of the prospects and challenges associated with the expansion of renewable electricity.*

We predict that the coming decade or two will entail dramatic changes in the European and Nordic electricity supply, regardless of the policies that are implemented. New capacity enters the market primarily through support systems and is dominated by variable and non-dispatchable technologies. At the same time primarily thermal and dispatchable supply is phased out due to lack of profitability and due to aging. Several of the issues we deal with here are common for Europe and the Nordic countries. In some cases, however, there are obvious differences.

EU energy and climate policy

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

The year 2020 energy and climate package

The targets for the year 2020 energy and climate package were set by EU leaders in March 2007 and enacted in year 2009 (EC, 2009a; EC, 2009b and EC, 2009c). The package includes a set of binding legislation that is aimed at reducing GHG emissions by 20% by year 2020 based on emission levels in year 1990, and increasing the level of RES to 20% of final energy. Even though it is not directly included in the year 2020 package, a third goal to reduce primary energy consumption or, alternatively, to increase energy efficiency, is also considered in the overall policy package for year 2020 (EC, 2012). The energy efficiency goal is expressed as a target: to reduce primary energy consumption by 20% relative to a baseline projection for year 2020, which originates from a PRIMES model run from year 2007 (EC, 2007).[4] Unlike the emissions reduction and renewable targets, the efficiency target is not translated into binding legislation. Thus, rather than introducing binding targets at the national level, it stipulates "binding measures", such as an obligation to renovate public buildings and other initiatives. We will elaborate further on the three different policy objectives in the forthcoming sections.

The year 2030 framework

Following the Green Paper on a year 2030 framework for energy and climate policies (EC, 2013a), both the European Parliament and the European Commission presented in early 2014 their views and positions on the next step in European climate and energy policy: the goals for year 2030. The Parliament voted in February for a binding of 40% reduction in GHG emissions by year 2030 (European Parliament, 2014). Furthermore, renewable energy shall, according to the proposal of the Parliament, supply 30% of total final energy use by year 2030 through the enactment of binding targets. An ambition to reduce energy use by 40% by year 2030 was also expressed. Prior to the vote

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

of the Parliament, the Commission presented its new energy and climate package for year 2030 in January 22, 2014, which featured somewhat less ambition than the version proposed by the Parliament (EC, 2014a). Although the Commission and Parliament share the view on GHG emissions reductions, the Commission proposes a target for RES of 27% by year 2030. The RES target is proposed to be binding on the EU level but not on the Member States' levels. No specification was made concerning a possible efficiency target pending the new progress review of the year 2020 efficiency target, which is due in June 2014 (Euractive, 2014a).

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

The vote of the European Parliament itself is not legally binding, and an agreement will need to be reached between the Commission, Parliament, and Member States (the Council) before a final proposal can be signed on, later this year (Euractive, 2014c).

The Roadmap 2050

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

Current status and projections of the GHG reduction target

In the previous sections, we briefly presented the three major milestones (years 2020, 2030, and 2050) and the corresponding energy and climate policy goals for the EU. Figure 1 shows these goals for GHG emission reductions, together with the actual development since year 1990, and the projected emissions taken from the Member States' own reported emission trajectories or projections. We conclude that emissions have steadily decreased since year 1990 to the present day. However, we must not forget that the global recession, which started in late 2008 and from which we still are recovering, has had a significant impact on the decreasing trend. Summing the projections provided by the Member States indicates that the GHG targets for year 2020 will be met or even surpassed by 1 to 4 percentage points. Most of the Member States' reports also include projections up to year 2030. If these projections are summed, they indicate a significant halt in emission reductions between year 2020 and year 2030. According to these projections, the reductions would amount to 22% by year 2030 assuming current policy instruments, and 28% by year 2030 if one includes also planned measures. These values are significantly lower than the 40% envisaged in the year 2030 framework. In the figure, we have also included the latest reference projection by the European Commission up to year 2050, which was presented in December 2013 (EC, 2013b). According to this projection, emissions are estimated as being somewhat lower, with a 32% reduction by year 2030, than the sum of the Member States' projections, which forecast emissions reductions of 22%–28% (see Figure 1). By year 2050, the same reference case yields a reduction in GHG emissions of 44%, based on the levels in year 1990. This projected reduction is very different from the year 2050 ambition of at least 80%. Thus, it seems likely that policy measures will need to be stringently enforced if the goals are to be met. The information reported in Figure 1 underlines the enormous challenges that lie ahead up to year 2050: the same emission reduction (20%) that we have achieved in 25 years (between 1990 and 2014) is to be achieved in three consecutive decades (2015–2030, 2030-2040 and 2040-2050), so as to reach the goal of 80% reduction in GHG emissions.

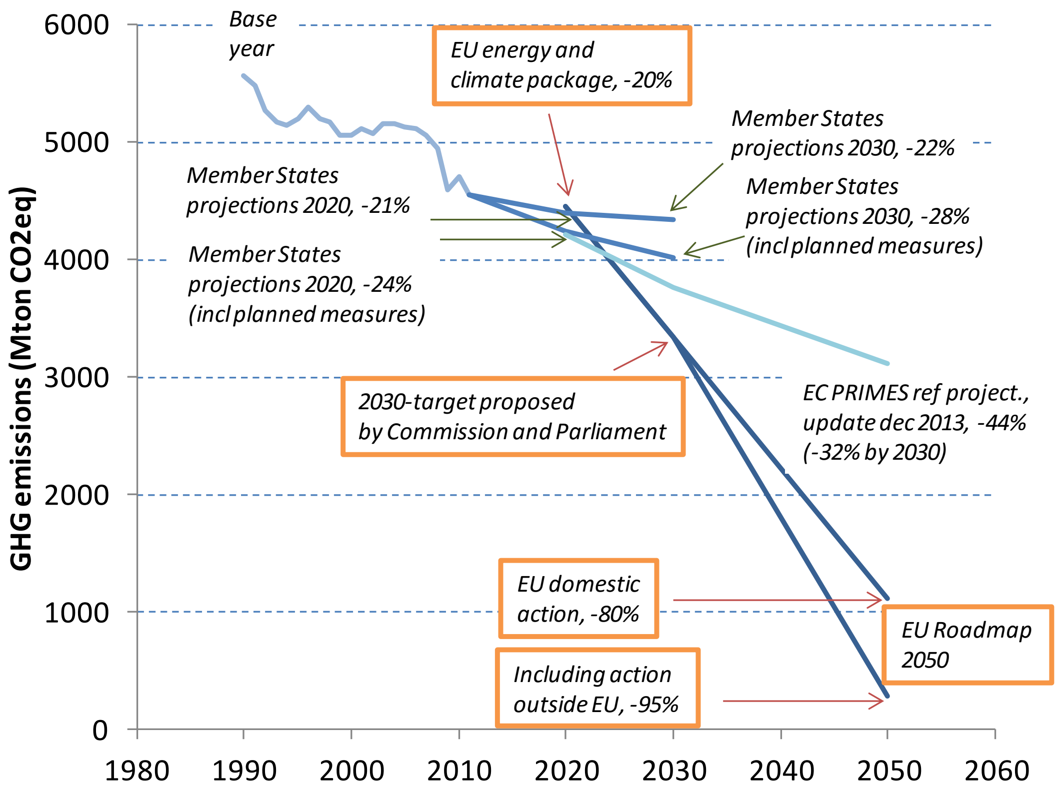


Figure 1. GHG trends, projections, and targets for the EU-28, as given by EU common and national frameworks. Sources: European Environment Agency (2013) and EC (2013).

Factors behind the reduction of greenhouse gases between 1990 and 2012

The emissions of GHG:s have been reduced by approximately 1150 Mt CO_2-eqv/year (20%) in EU 28 during 1990-2013, and they amount to around 4450 Mt CO_2-eqv/year today (European Environment Agency, 2014). This is a significant reduction and it means that the EU already has reached its target of20 % by the year 2020.

Largest is the reduction of carbon dioxide emissions, which equals 750 Mt CO_2-eqv/year, but the reduction of methane and nitrous oxide is also considerable – about 200 Mt CO_2-eqv/year each. In percentage terms, the reduction of methane and nitrous oxide emissions is clearly larger than for carbon dioxide, more than twice as large. The emissions of other GHGs (SF6, PFCs and HFCs) are small compared to the emissions of carbon dioxide, methane and nitrous oxide, and are therefore not covered by this report.

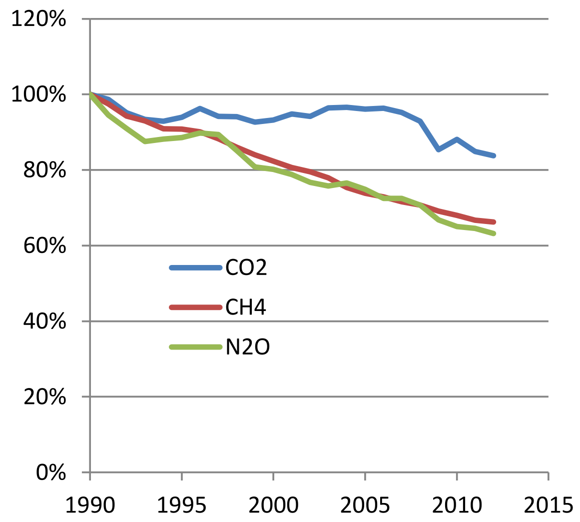


Figure 2. Development of the emissions of carbon dioxide, methane and nitrous oxide during the period 1990-2012.The figure shows the percentage development of emissions relative to the levels in 1990. Source: European Environment Agency (EEA 2014a).

Approximately 30% of the reduction of GHG emissions in the EU since 1990 is related to the economic development (GDP), according to the EU's environmental body European Environment Agency (EEA 2014b). The economic downturn in Eastern Europe in the early 90s, and the global economic crisis since 2008 are the main factors. The increased use of renewable energy in the energy systems since 1990 might, according to NEPP (2014a), explain another 25-30% of the reduction of the emissions of GHGs, and an even larger share of the reduction of carbon dioxide emissions. The investment in renewables is thus the CO_2 effort that has had the largest impact historically.

Almost of the same significance for the reduction of GHGs in the EU are the (combined) measures in agriculture, waste management and fuel exploitation/management, which have reduced the emissions of methane and nitrous oxide. So together, these three factors – the GDP changes, investments in renewables, and the actions for methane and nitrous oxide reduction – explain a very large part of the GHG reduction between 1990 and 2012[5].

[5] Besides these three major efforts, several other measures have been taken; fuel replacement, energy efficiency optimization, structural changes in industry and commerce, etc. According to NEPP (2014a), these actions have had less impact than the three main measures.

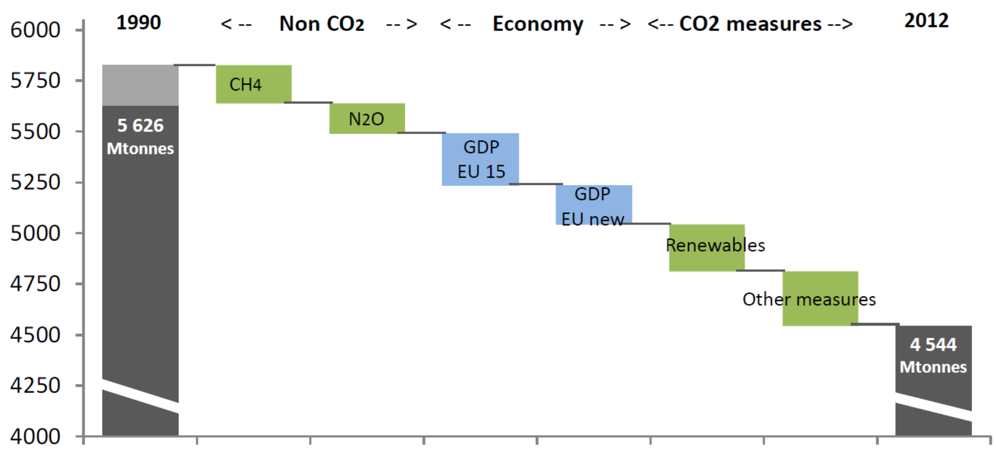


Figure 3. A collected view of the factors behind the reduction of GHGs in EU 28. The reduction is presented relative the emissions in 1990. Source: NEPP (2014a).

The newest Member States have reduced their emissions of GHGs more than the old ones (EU15)

GHG emissions have been reduced more in the newest Member States in EU than in EU 15, in absolute as well as in percentage terms[6] (European Environment Agency, 2013). The large reduction in the new Member States happened in the early 90s, during the economic downturn in Eastern Europe, but the reduction has continued even after that. In EU 15 on the other hand, the (combined) GHG emissions *increased* by a few percent up to 2005 when they started to decline, and in 2012 they were a bit more than 10 % below what they were in 1990. The emissions of carbon dioxide in EU 15 increased even more up to 2005, by 8-9 %, and thereafter they declined slightly more than 15 % during 2005-2012. The economic crisis is an important factor behind this rapid decline, but also the implemented energy and climate policies, specifically the investments in renewable energy.

The GHG emissions in Sweden were reduced by 21% between 1990 and 2012, significantly more than the average in EU 15. But, for the Nordic countries in total the reduction was only 14 %, i.e. in line with EU 15. Denmark, Sweden and Finland reduced their emissions, whereas Norway and Iceland *increased* theirs during 1990-2012. In percentage terms, the emissions of CH_4 and N_2O were reduced twice as much as the co_2 emissions, in Sweden as well as in the Nordic countries as a whole.

Sweden is one of the countries in the EU with the lowest emissions of GHGs, both per capita and as related to GDP. Despite this, we have reduced our emissions faster than many other EU members. As a result of the larger reduction of emissions in the newest EU Member States, they are now at an emission level per capita equal to the other EU countries. But expressed as emission per GDP unit, the new members are still at levels clearly higher than EU 15. In the Nordic countries, the emissions per capita is about the same as for the EU as a whole, but per GDP unit the Nordic countries are at a lower level than the EU.

---

[6] Sweden is part of EU 15.

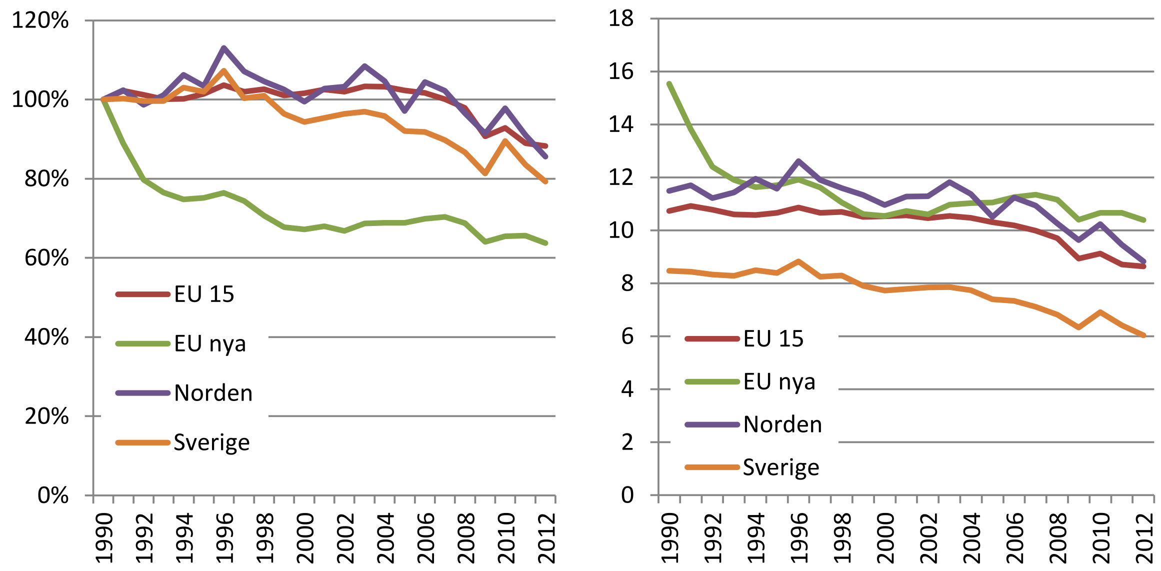


Figure 4. Development of the total GHG emissions (left panel) and the emissions per capita (right panel) for four geographical areas (EU nya=the 13 new member states; Norden=the Nordic countries; Sverige=Sweden). Source: EEA (2014a), Eurostat (2015).

Important policies in GHG emission reductions

A number of policies have played a key role in GHG emission reductions (EEA 2013b), including:

- The EU Nitrates Directive,
- the Common Agricultural Policy,
- the EU Landfill Directive,
- the EU Directive on the Energy Performance of Buildings,
- the EU Large Combustion Plant Directive and
- the EU Climate and Energy Package.

It is also important to note that many policies at Member State level are additional to these EU policies.

Climate and energy policies from the Climate and Energy Package, e.g. the EU ETS and the Effort Sharing Decision, are also projected to have a strong impact in the run-up to 2020.

The EU ETS – a key instrument to reduce GHG emissions

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

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

Recent development in the EU ETS market

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

In Figure 5, the historical development of the EUA price is shown starting from the introduction of the EU ETS in year 2005 (left panel). The dramatic fall in price in year 2007 was the result of an oversupply of emission allowances during the first trading period of 2005–2007, which could not be used in the second trading period of 2008–2012. Since 2008, EUA prices have decreased continuously, as discussed above. Forward prices on the market indicate persistently low prices until year 2020, generally at levels <10 €/t CO_2. In Figure 5 (right panel), the historical price development is supplemented with projections taken from the Roadmap modelling (EC, 2011c) and from IEA's World Energy Outlook (2012). The Roadmap scenarios differ from each other, mainly in terms of technological developments and technology options. In these scenarios, the EUA price exceeds 100 €/t$CO_2$by year 2050, and in some scenarios, it goes higher than 200 €/t CO_2. In the reference scenarios, both in the IEA WEO and the Roadmap modelling, EUA prices increase significantly from current prices and levels to around 50 €/t CO_2 post-2030. In these scenarios, the EU climate policy targets for year 2050 are not met. Nevertheless, the levels of emissions are reduced, typically by around 40% compared to the levels in year 1990. Thus, the model analyses indicate a considerable gap between the existing EUA price level and the projected price levels assuming that long-term policy targets are met.

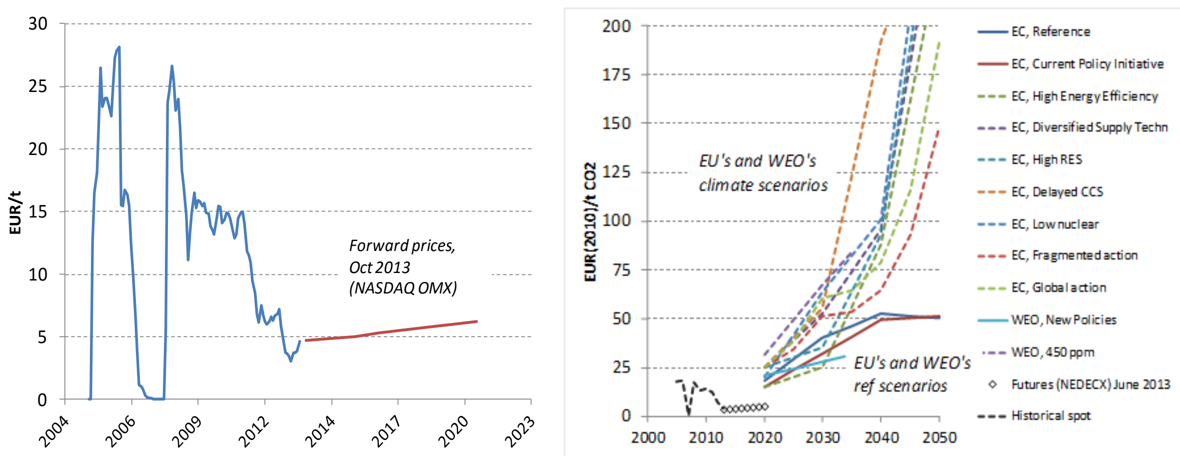


Figure 5. Historical and futures prices of EUA (left) and projected EUA prices in the EU Roadmap study and WEO 2012 (right). Sources: NASDAQ OMX, EC 2011 and WEO 2012.

Existing imbalance in the ETS market

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

- Record use of international credits,
- auctioning of Phase 2 (2008–2012) allowances and the remaining allowances in the new entrant reserve,
- early auctioning of Phase 3 allowances and
- sales of Phase 3 allowances to generate funds for the NER300 programme. [7]

In the absence of new measures, this imbalance in supply and demand of emissions allowances is projected to continue for the next 10–15 years and is likely to keep EUA prices at low levels (c.f. Figure 6). This is obviously problematic in terms of investment incentives for CO_2-lean technology.

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

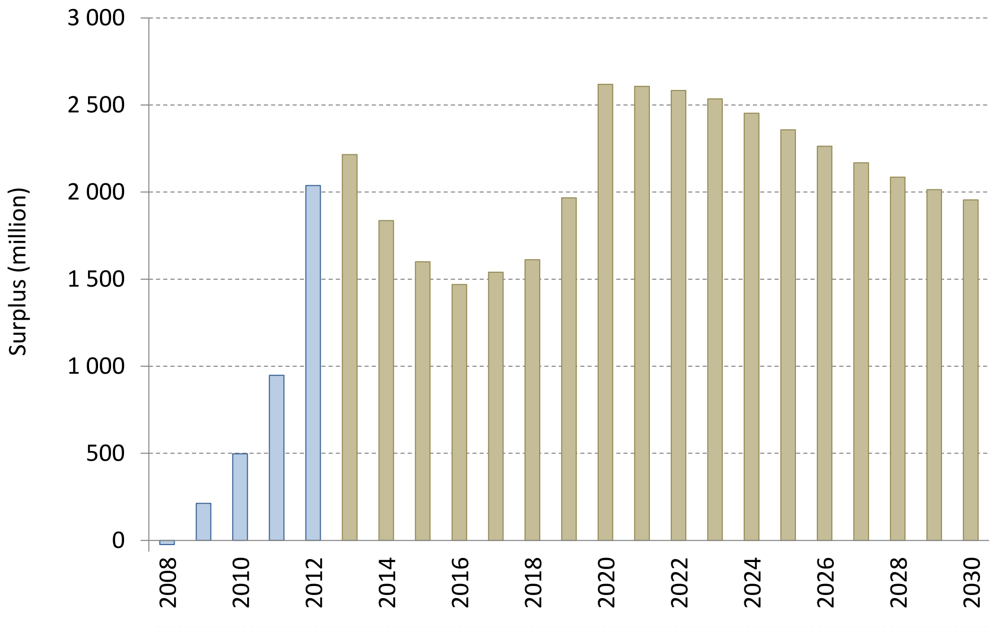


Figure 6. Accumulated surplus of emissions allowances. The blue columns are based on actual values, whereas the green columns are estimated values (EC, 2014b).

As a short-term measure to tackle the imbalance of supply and demand, the European Commission is postponing the auctioning of 900 million allowances (so-called “back-loading”). According to the latest draft amendment of the EU ETS Auctioning Regulation on back-loading, which was endorsed by the EU Climate Change Committee on January 8, 2014, the reductions in allowances will be 400 million in year 2014, 300 million in year 2015, and 200 million in year 2016. Thereafter, the increases in the numbers of allowances, i.e., the re-entry of emissions allowances, will be 300 million in year 2019 and 600 million in year 2020. The amendment has to be scrutinised by the Council and the European Parliament's Environment Committee by the end of March 2014 to achieve the planned back-loading volumes (EC, 2014g).

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

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

The market stability reserve

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

In the final layout of the year 2030 framework in late autumn 2014, the European Council underlined that a reformed, well-functioning ETS with an instrument to stabilise the market in line with the Commission's proposal will be the main instrument to achieve greenhouse gas emission reduction.

Recent fossil-fuel price development and its impact on electricity generation

Since EUA prices have been low in recent years, the use of coal as a fuel for electricity generation has proven more profitable than the use of natural gas. However, this does not fully explain why the use of coal in the EU has increased while the use of natural gas has decreased since year 2010. In the US, the cheap exploitation of unconventional gas, especially shale gas, during the past few years has led to a situation where the use of gas is more profitable than the use of coal in many sectors, including electricity generation. Therefore, the switch from coal to gas in the US has created an oversupply of coal on the global market, which has influenced coal prices in Europe. In Figure 7, the price development patterns for steam coal and natural gas are presented. It is clear that the price of coal has dipped twice since year 2008. The first dip came as a result of the global recession in year 2009, which reduced the demand for coal worldwide, and the second dip resulted from an abundant and cheap global coal supply, partly caused by the unconventional gas exploitation in the US. In the case of gas (and crude oil), only one such dip is clearly evident. Futures prices for coal and gas (in late autumn 2013) reveal different trajectories for the two fuels: increasing coal prices and decreasing gas prices. Thus, gas may strengthen its competitiveness against coal, especially when one considers that EUA prices are also expected to increase, albeit at a slow rate. Long-term price projections estimated by the IEA (2013) are also included in Figure 7. The higher price trajectories assume business-as-usual with increased global demand for coal and gas, while the lower price developments assume global climate-mitigation policies with reduced demand for fossil fuels and, thus, decreases in the prices of fossil fuels.

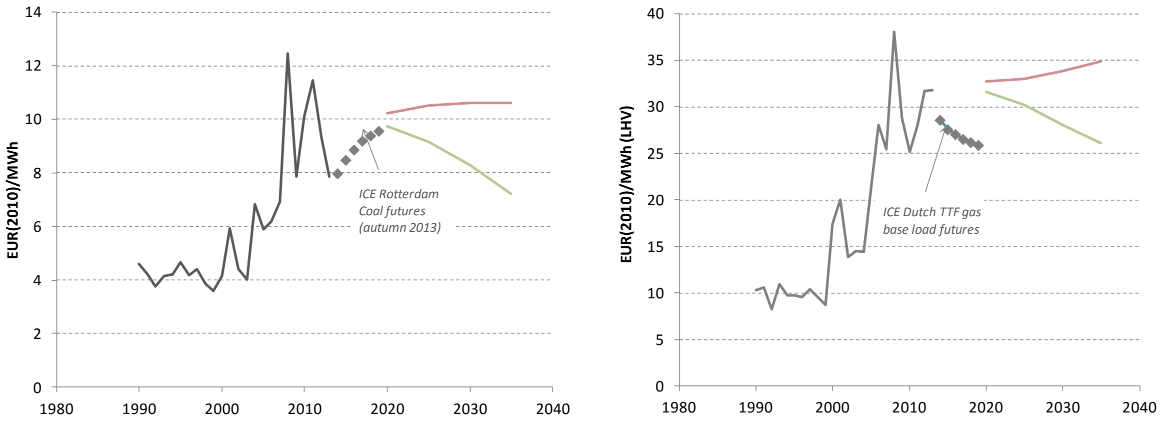


Figure 7. Steam coal prices (OECD imports; left panel) and natural gas prices (European imports; right panel). Also included are two price projections for each fuel: one baseline projection (the upper projection towards year 2035); and one global climate-mitigation scenario projection. Sources: ICE future prices; IEA World Energy Outlook 2013; BP Statistical Review of World Energy 2013.

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

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

As mentioned before, the share of renewables, especially for electricity generation, has grown significantly in many EU Member States. In year 2005, the RES share of total gross consumption was approximately 9%. By year 2013, the share had grown to 15% (Figure 8). By year 2020, the corresponding share will be, according to the EU Renewable Energy Directive (RED), 20% (EC, 2009c) and the 2030 target is 27%. According to the Member States' NREAPs, 23 out of the, at that time, 27 Member States projected in year 2010 that they would reach their binding renewable energy targets for year 2020 on their own without making use of the co-operation mechanisms that are presented in the RED (EEA, 2013). Ten of the Member States were expecting a surplus of renewable energy by year 2020. Taken together, the NREAPs indicate that the binding RES target will be fulfilled by year 2020. However, a more recent analysis presents a somewhat different outlook (EC, 2013c), concluding that the Member States will need to increase their efforts even further if they are to achieve collectively the binding targets for year 2020. It is of particular importance that the larger Member States step up their efforts.

It is crucial that countries such as UK, France and Netherlands achieve their targets. They are only a fourth on their way reaching their renewable energy goals between 2005 and 2012, i.e. half the time through their commitment. Germany and Spain, often referred to as model countries, are only half way through to where they should have been in 2012. Together, these five countries must bring about another 500 TWh of renewable energy by 2020 (and reduce their energy consumption) to deliver to their commitment, so that the EU's20 % target can be achieved. Between 2005 and 2012 they accomplished 300 TWh, The other 23 Member States only need to achieve another 150 TWh renewable energy together, since they already have achieved more than 300 TWh between 2005 and 2012.

Then – depending on how much reduction of the energy use that is reached – Another 600-800 TWh of renewable energy must be realised in EU between 2020 and 2030 to reach the 27% target for 2030. This will be a challenge of at least the same magnitude as the 2020 target.

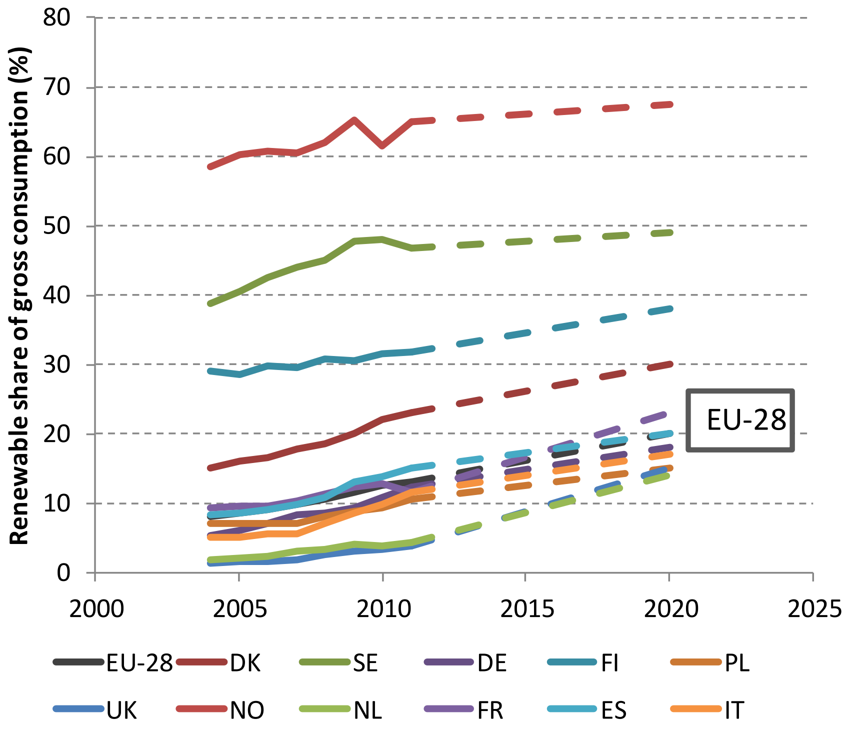


Figure 8. Shares of renewables of total gross energy consumption in the EU-28 and in selected EU Member States (and Norway), and the targets for year 2020, as stated in the Renewable Energy Directive (RED), (Source: EUROSTAT).

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

The historic trend of renewable electricity generation, presented as the share of gross electricity consumption, is shown in Figure 9 for selected Member States, Norway, and the entire EU-27. Some of these countries (e.g., Norway and Sweden) already have large renewable shares, thanks to abundant hydropower resources. Other countries, such as Denmark, Germany, Spain, and Ireland, have increased their shares considerably since year 1990 by extensive exploitation of other renewable resources, such as wind and solar power. The total share of RES-E in the EU-27 has grown from around 10% in year 1990 to around 20% in year 2011.

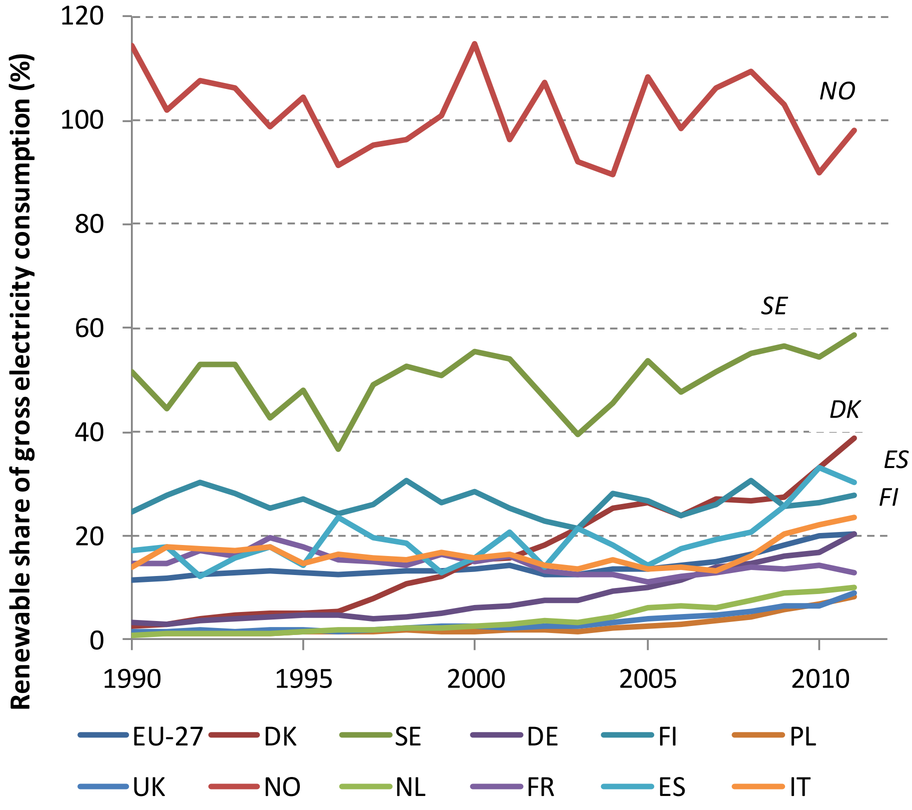


Figure 9. Share of renewable electricity in relation to gross electricity consumption. Source: EUROSTAT.

The rapid development of renewable electricity generation – the German case

In terms of the growth of installed RES-E capacity since year 1990, Germany cannot be surpassed in the European perspective. The provision of generous support through feed-in tariffs regulated by the EEG (Erneuerbare Energien Gesetz), the renewable energy legislation, has led to a dramatic increase in RES-E capacity. This capacity has increased from around 5 GW in year 1990 to almost 80 GW in year 2012 (Figure 10), which is of the same magnitude as the maximum peak load in one year in Germany. However, this rapid development has not occurred without controversies related to very high end-user costs, electricity-grid expansion (while development has been very fast on the production side, it has lagged behind significantly on the transmission and distribution sides), and the exemptions made for electricity-intensive industries (Handelsblatt, 2014). High end-user costs apply to households, commerce and a proportion of industrial consumers that finance the feed-in tariffs through electricity bills. These issues will have to be dealt with in the revision of the renewable energy legislation that currently is subject to negotiations within the year 2013 elected grand coalition. The exemptions for electricity-intensive industries have been queried by the EU Commission, which argues that the exclusion of German electricity-intensive industry from the EEG-Umlage, i.e., the additional fee charged in the electricity bill to finance the feed-in tariffs, is a violation of EU competition laws. Regardless, wholesale electricity prices have decreased substantially in Germany as a result of the dramatic increase in renewable capacity. Low wholesale electricity prices are of course beneficial to electricity-intensive industries, given that they do not have to pay for the support of RES-E expansion.

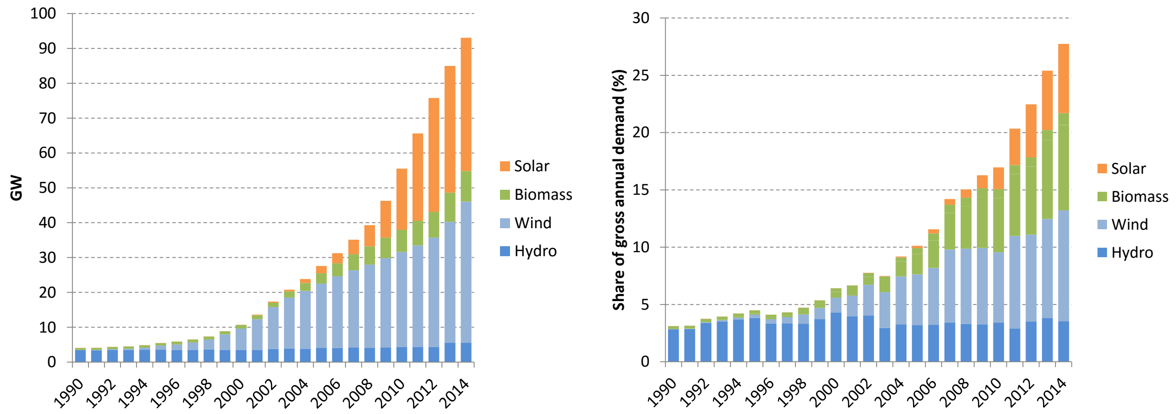


Figure 10. Installed capacities of renewable electricity generation in Germany (left panel) and Germany's relative share of renewable electricity generation in relation to gross demand for electricity (right panel). Source: Bundesministerium für Wirtschaft und Energie (BMWi), 2015.

The common Swedish-Norwegian electricity-certificate scheme

Since the beginning of 2012, a common Swedish-Norwegian electricity-certificate scheme is in place in order to increase the contribution from renewable electricity by 26.4 TWh together in both countries between 2012 and the beginning of 2020. The current system will be in place until 2035 and generators will receive electricity-certificates for a period of 15 years. The certificate scheme enables both Sweden and Norway to meet their commitments according to the RED. The RED includes various so-called "cooperation mechanisms" which implies that a Member State may achieve a proportion of its target abroad. Common support schemes, such as the Swedish-Norwegian electricity-certificate scheme, are defined as one of these "cooperation mechanisms" in the RED, The common Swedish-Norwegian electricity-certificate scheme was preceded by a separate national Swedish scheme between 2003 and the end of 2011. Under that regime, the renewable electricity generation in Sweden was increased by around 13 TWh during the same time period which was more than the stipulated 11.8 TWh according to the quota curve. Wind power accounted for more than 5 TWh of that increase, while the rest is assigned to primarily biomass power.

In Figure 11 (left panel), we present the electricity generation by technology and country within the "26.4 TWh" target since the beginning of the common scheme, i.e. 2012. In the right panel in the same figure, we present the electricity-certificate price in SEK/MWh (nominal prices). We may conclude that Swede, hitherto, totally dominates the supply of electricity-certificates and that wind power is the major supplying technology. At the end of 2013, somewhat more than 6 TWh of renewable electricity has been introduced since the beginning of 2012. In order to reach the stipulated 26.4 TWh by 2020, the pace of increase must be approximately 3 TWh per year which fairly well corresponds to the current pace.

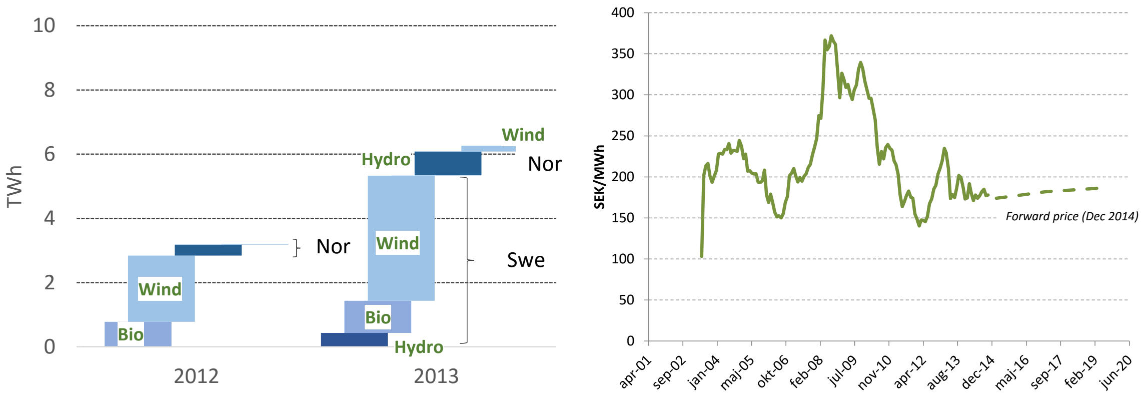


Figure 11. Increase in renewable electricity generation in the common Swedish-Norwegian electricity-certificate scheme since the beginning of 2012 (normal-year production; left panel) and historical electricity-certificate prices (between 2003 and 2011 in the separate Swedish scheme and between 2012 and 2014 in the common scheme; right panel). Source: Swedish Energy Agency (2014) and SKM (2014).

Recent cost developments in wind and solar power generation

As mentioned before, the growth in renewable electricity generation has been spurred by a variety of support schemes across the EU. In addition, this growth has been promoted by the significant reductions in purchase costs of RES technologies that have occurred over the past few years, especially in the case of PV cells. In Figure 12, left panel, the overall electricity-generation costs of PV cells (small-scale rooftop and large-scale stand-alone installations) are shown, as reported by the Fraunhofer Institute for German conditions during the past few years (Fraunhofer, 2013; 2012 and 2010). However, the total electricity-generation costs of PV installations remain far above the wholesale electricity prices (exemplified by the German spot price; the blue line in Figure 12). Nonetheless, grid parity may be within reach if PV electricity generation costs are compared with retail electricity prices, as this is a more appropriate profitability index for small-scale roof-top installations that are owned by private persons. In Figure 13, essentially the same information on the cost development of PV cells is given, but this time for Swedish conditions based on purchase-price observations (price per kW). As in the German case described above, small-scale installations in particular experience a rapid reduction in purchase costs.

The costs of wind power have not exhibited the same decrease as solar power over the past few years, which indicate that this technology has achieved a higher level of technology maturity (Figure 12, right panel). On the other hand, given the high global demand for wind power, the cost reductions achieved in the manufacture of wind turbines may not be completely reflected in the wind-turbine purchase price paid by the wind power owner or operator. Interestingly, the reported costs of offshore wind power seem to increase over time as experience in the use of this technology increases. It is likely that, for example, the maintenance costs of offshore installations in what are often very harsh weather conditions have been underestimated previously.

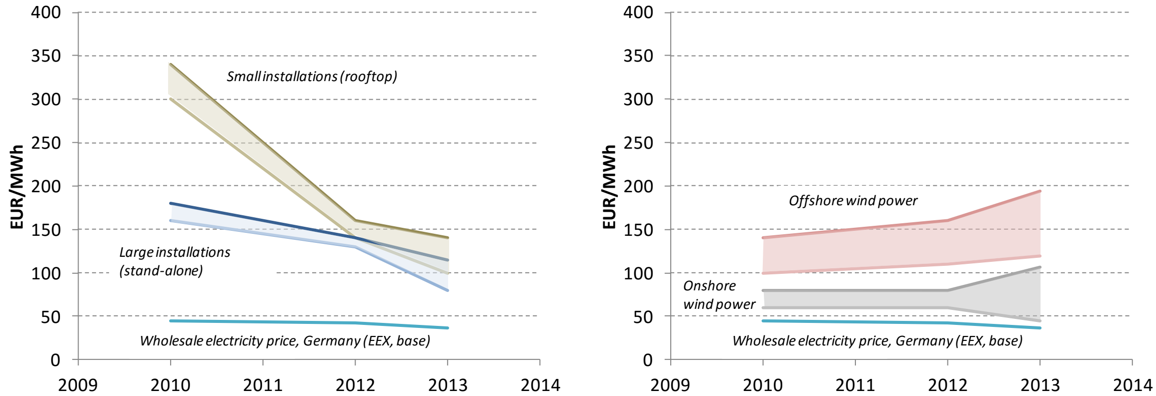


Figure 12. Estimated electricity-generation costs (and intervals) of PV installations (left panel) and wind power (right panel) in Germany between 2010 and 2013. Source: Fraunhofer, 2013; 2012 and 2010.

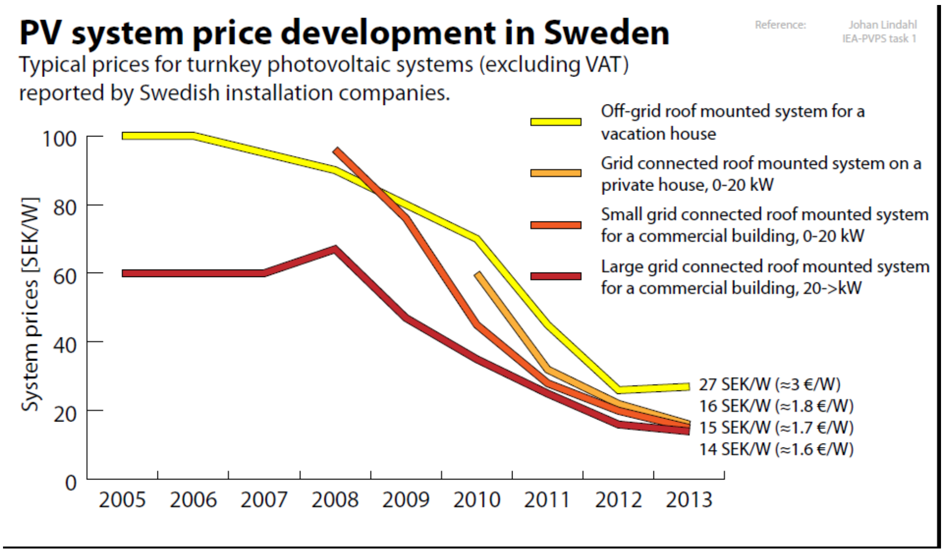


Figure 13. PV wholesale price development in Sweden, 1 EUR≈9 SEK. Source: IEA-PVPS, 2013.

As mentioned above, the rapid integration of renewable energy and electricity is not without controversy. Certainly, while this development is desirable in terms of climate change mitigation, the associated challenges can neither be neglected nor underestimated. We have previously mentioned the relatively high costs for electricity consumers in Germany (as the example) which have resulted from the significant expansion of renewable electricity spurred by the German feed-in tariff scheme. Furthermore, variable renewable electricity capacity with a relatively low production-to-capacity ratio (compared to, for example, base-load thermal power plants) inevitably requires investments in additional transmission and distribution capacity if such electricity production is to be fully utilised (rather than suffering significant curtailment due to transmission bottlenecks). The issue of back-up capacity to cope with periods of low availability of wind and/or solar irradiation also needs to be considered carefully. Moreover, it is not uncommon for a clash to occur between the use of renewables for energy supply, e.g., biomass extraction and wind-power installations, and other land-use interests. All these challenges and considerations associated with the likely (and needed) substantial increase in the exploitation of renewable energy sources are important if the transition towards sustainable energy and electricity systems is to be accomplished in as efficient a manner as possible. As emphasised before, these are, among others, the issues and research topics that have been in focus throughout the research process.

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

The third cornerstone of the EU energy and climate policy package is concerned with saving energy and increasing energy efficiency. The Energy Efficiency Directive (EED) entered into force on December 4, 2012 (EC, 2012). Most of its provisions are to be implemented by the Member States by June 2014 at the latest. The EED aims at meeting the target of reducing primary energy consumption by 20% by year 2020 and 27% by year 2030 as compared with the baseline projection made in year 2007. Rather than introducing binding targets at national levels, the EED instead contains binding measures, such as an obligation to renovate public buildings and other initiatives.

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

In year 2005, primary energy (PE) consumption (defined as gross inland consumption minus non-energy use) amounted to around 1711 Mtoe. Model runs initiated by the Commission from year 2007 and for a business-as-usual scenario projected growth in gross PE consumption to 1842 Mtoe by year 2020 (EU-25). This level sets the basis for the target of 20%, i.e., 1474 Mtoe, by year 2020. Over the years, efficiency measures and policies have gradually increased the prospects for reaching that goal. Recent projections estimate a total primary consumption of <1600 Mtoe for the EU-28 (see Figure 14). Thus, even though the target seems to be within reach, we must not forget that the European economy still struggles with the effects of the global recession of 2008–2009. To proceed with reducing energy use towards the year 2020 goal, additional measures are likely to be needed.

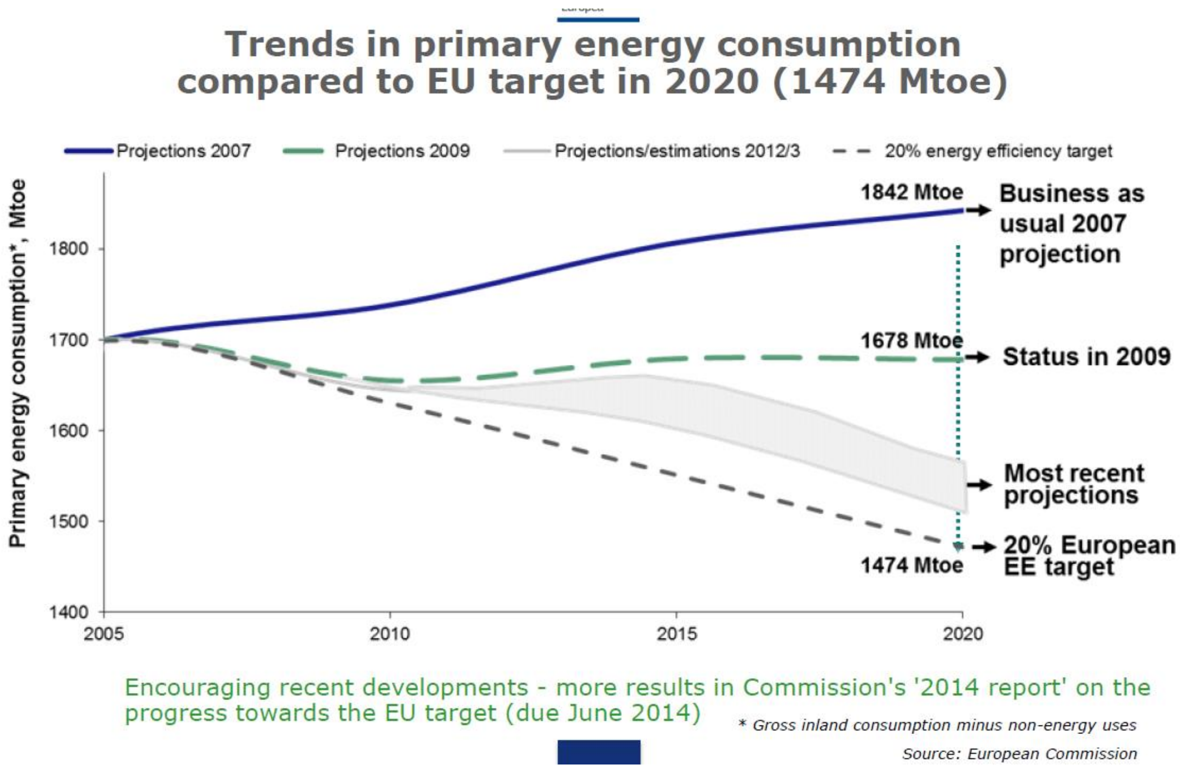


Figure 14. Primary energy consumption target and projected consumption levels. Source: Miladinova (2013).

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

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

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

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

The different RES-E support schemes in use today across the EU are shown in Figure 15.

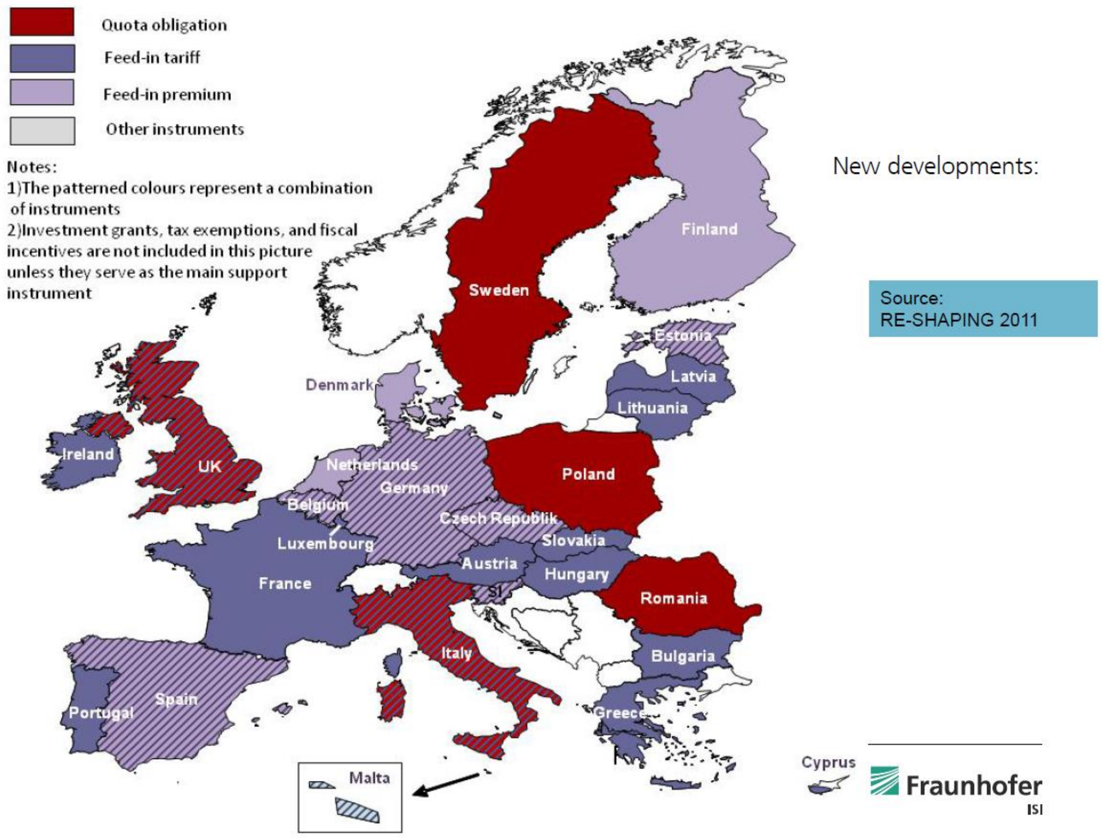


Figure 15. RES-E support schemes in use in Europe in year 2011 (Source: RES LEGAL Europe 2014).

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

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

For more than two decades, investments in new power generation across Europe have predominantly been made in gas-fired plants and renewable electricity generation (see Figure 16). This is in clear contrast to the 1970s and 1980s when heavy investments were made in coal-fired and nuclear power. Furthermore, the capacity build-up in the last 10 years (2003-2013) has been dramatic from a historical perspective, with roughly twice as much investment in capacity as in the previous decades. This is mainly a result of the significant increase in renewable electricity-generation capacity, which has been spurred by different support schemes across Europe. Yet, for the RES technologies it should be kept in mind that the full-load hours, generally, are significantly fewer than for thermal power plants. Thus, on an energy basis, the fraction of RES-based electricity supply is less pronounced than shown in Figure 16.

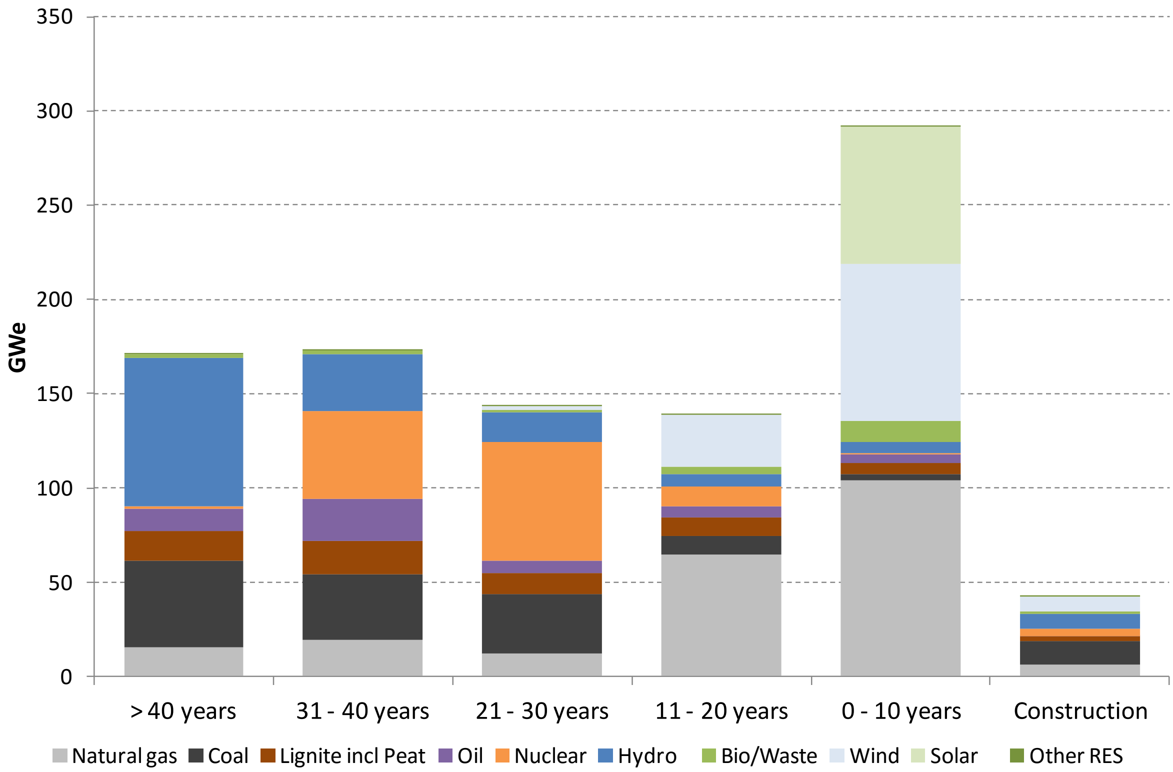


Figure 16. Age distribution of existing power plants in the EU-28, Switzerland, and Norway. Solar power and wind power plants under construction are, in principal, not included in the database. Source: Chalmers Power Plant Database, status March 2014.

From Figure 16, it is clear that a large share of the thermal power plant fleet in Europe is of advanced vintage, i.e. approaching the end of its life-span. This is true especially for the nuclear and solid-fuel power plants. Figure 17 further underlines this by showing, as a supplementary way to represent the age distribution, that around 40% of the existing *total* power plant capacity is *at least* 30 years old. In contrast, very few power plants are older than 50 years. The corresponding picture for the four Nordic countries is shown in Figure 18 .We may conclude that the existing capacity in the four Nordic countries amounts to roughly 10% of the total capacity in Europe. Furthermore, the capacity in the Nordic countries is, in relative terms, of more advanced vintage than in Europe as a whole. This is explained by the large share of hydro power schemes which generally are of more advanced age than e.g. thermal power plants.

Even if the technical life-time of a thermal power plant is largely plant-specific, the interval of 30–40 years is often referred to as a limit (see for example the assumptions made by IEA/Nordic Energy Research, 2013). For nuclear power, 50 years is typically mentioned as the potential limit for the technical lifetime. Thus, large phase-outs due to age are likely to occur across Europe in the coming 10–20 years. Based on these somewhat rough lifetime assumptions, approximately half of the European thermal power plant capacity will be phased out due to aging before year 2030. Meanwhile, the expansion of variable renewable electricity is likely to proceed at a rapid pace, which raises questions concerning the future availability of thermal back-up capacity.

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

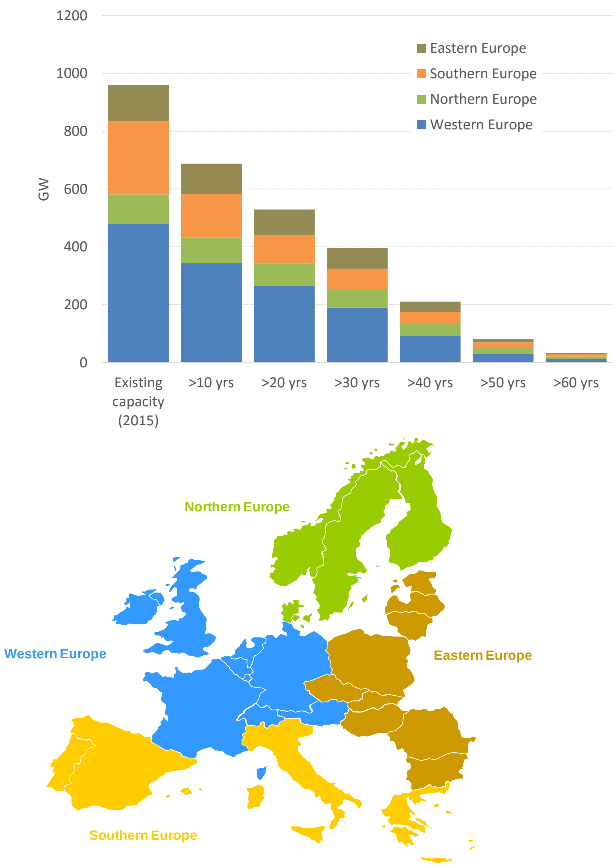


Figure 17. Age distribution of existing power plant capacity in Europe. Source: Chalmers Power Plant Database, status September 2014.

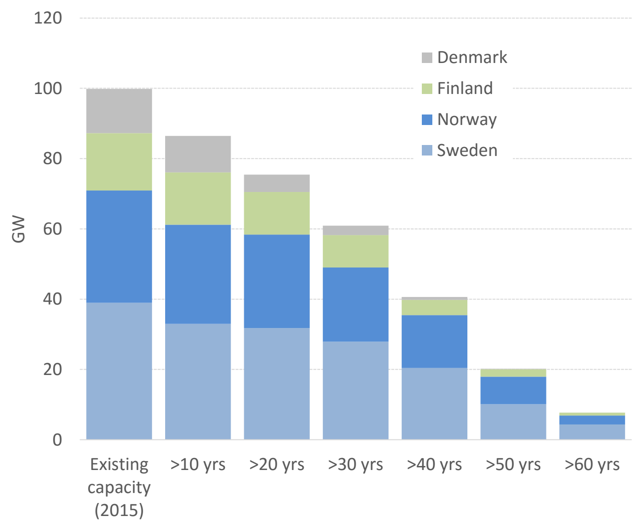


Figure 18. Age distribution of existing power plant capacity in the Nordic countries. Source: Chalmers Power Plant Database, status September 2014.

The Large Combustion Plant Directive (LCPD)

The decommissioning of older power plants in Europe is further spurred by the Large Combustion Plant Directive (LCPD; Directive 2001/80/EC). This Directive concerns combustion plants with a rated thermal input of at least 50 MW, irrespective of the type of fuel used. The purpose of LCPD is to set limits to the amounts of SO_2, NOx, and dust emitted from large combustion plants each year (EC, 2001). Thus, GHG emissions are not included. The LCPD requires power plants to either opt-in through environmental retrofitting and continue operation or opt-out and close down by year 2015 at the latest. It is foreseen that a considerable share of power plants will fall under the latter category.

The largest regional impact of the LCPD will be on power plants in the UK in terms of decommissioning. Estimates based on data from the Chalmers Power Plant Database reveal that around 12 GW of electrical capacity will be decommissioned in the UK alone. This corresponds to approximately 15% of the total installed electricity-generating capacity in the UK. A little more than 7 GW of that capacity has already been decommissioned by year 2013, following the LCPD. The estimated impact of decommissioning across the EU (presented as thermal capacity) is shown in Figure 19.

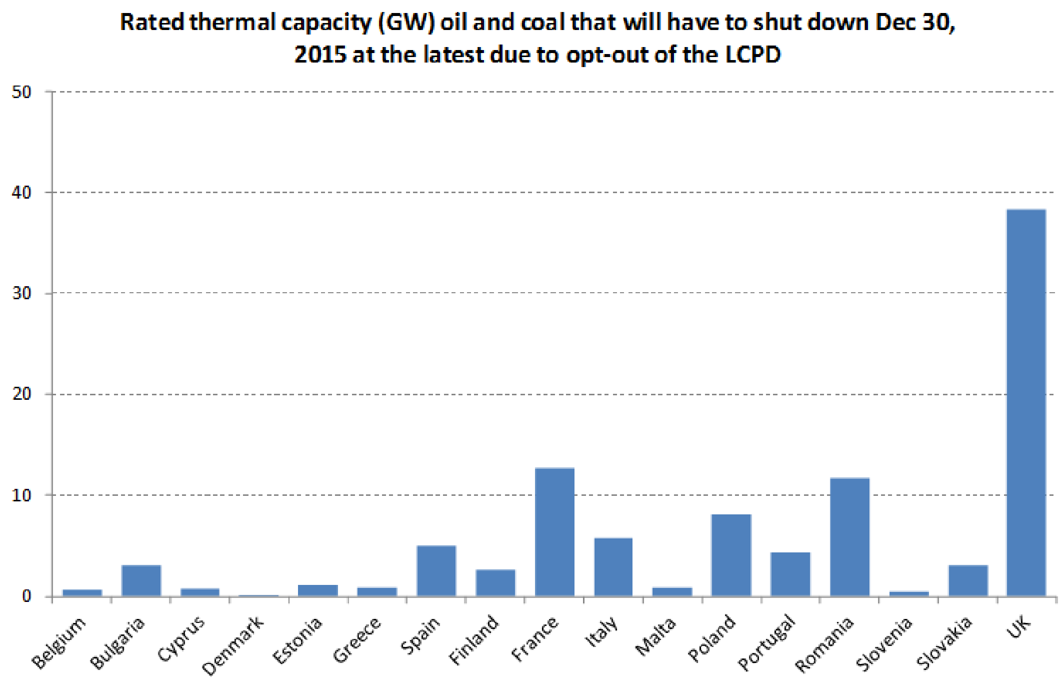


Figure 19. Rated thermal capacity (in GW) of oil- and coal-fired power plants that will have to be shut down by year 2015 in line with the LCPD (not all countries of the EU are affected. For instance, Germany has previously met the requirements through national regulations). Source: Chalmers Power Plant Database.

Aging and decommissioning due to the LCPD or other reasons are included in the Chalmers Power Plant Database, which is an essential component of the research presented in the present book. The Chalmers Power Plant Database describes the status and important features of virtually all power plants across the EU. In the research process, age and decommissioning data on existing power plants have been integrated into the comprehensive European electricity system modelling used in different areas of the research. The modelling clearly shows an extensive reduction in generation capacity over the coming years, induced by aging and decommissioning. Thus, a gap between demand and supply will emerge which will need to be filled with investments in new generation capacity. One example is shown in Figure 20, which presents the results for one of the four main scenarios presented later in this book. This scenario assumes, among other things, a continued growth in electricity demand. This assumption places an extra pressure for new investments, as compared with a scenario with a stagnating or declining electricity demand (also part of the scenario analyses presented further on in this book). According to Figure 20, approximately 30% of the existing electricity generation is phased-out due to aging or other reasons (such as unprofitability) by year 2030. On the other hand, the Chalmers Power Plant Database also shows, as we mentioned earlier, the long lived nature of the existing power plant stock which in the modelling remains far into the period towards year 2050. By year 2050, the existing system can be expected to be in large part replaced by a new system.

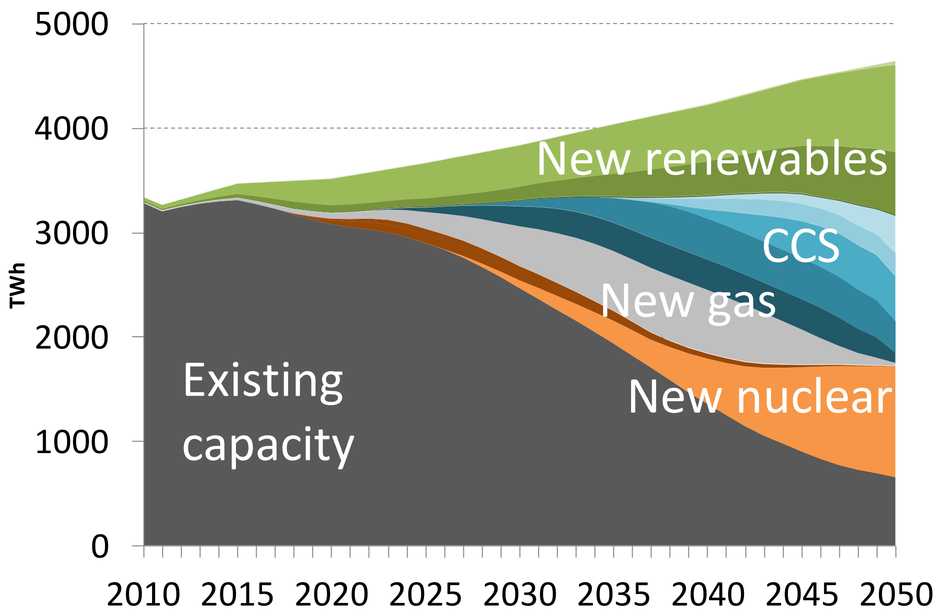


Figure 20. European electricity generation subdivided into existing capacity and new capacity towards years 2050 (model calculations based on Climate Market scenario assumptions).

Status and prospects of CCS

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

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

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

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

Nuclear power

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

A controversial technology

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

The European nuclear power plant fleet

In Figure 21, we present the nuclear power plants (sites) that are currently in operation across the EU-28 and Switzerland. The age distribution of these plants is reported in Figure 22. We conclude that in 15 years’ time, roughly 80% of the nuclear power plants in Europe will be older than 40 years.

Figure 21. Nuclear power stations (sites) currently in operation in the EU-28 and Switzerland (2013). Source: Chalmers Power Plant Database.

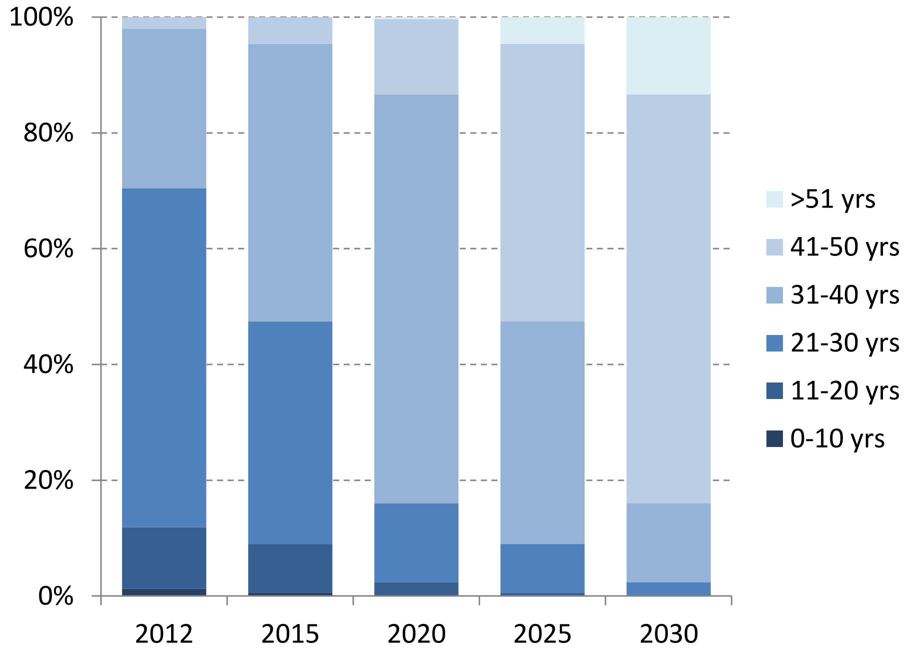


Figure 22. Age distributions of the existing nuclear power plants in the EU-28 and Switzerland for different years (Source: Chalmers Power Plant Database).

Figure 23 presents another view of the subject of nuclear power in Europe. Under the assumption that all nuclear power plants currently in operation have a total technical lifetime of 60 years, we can produce a phase-out curve for the entire nuclear capacity. Apart from the four reactors that are currently under construction, we assume that no new plants enter into operation. In Germany, the phase-out of nuclear power plants follows the governmental decision and not the assumption of 60 years of technical lifetime. Given these assumptions, only around 20 GW of the existing 130 GW would still be in operation by year 2050. From Figure 23, we can also conclude that the absolute lion's share of the existing capacity was commissioned between 1980 and 1990. This indicates that the engineering, manufacturing, and financial capacities, at least in a historic perspective, for such large investments over a relatively limited period have been of considerable size. We will show, in forthcoming chapters, that such massive investments, albeit not primarily in nuclear power, for limited periods of time will also be needed in the coming decades.

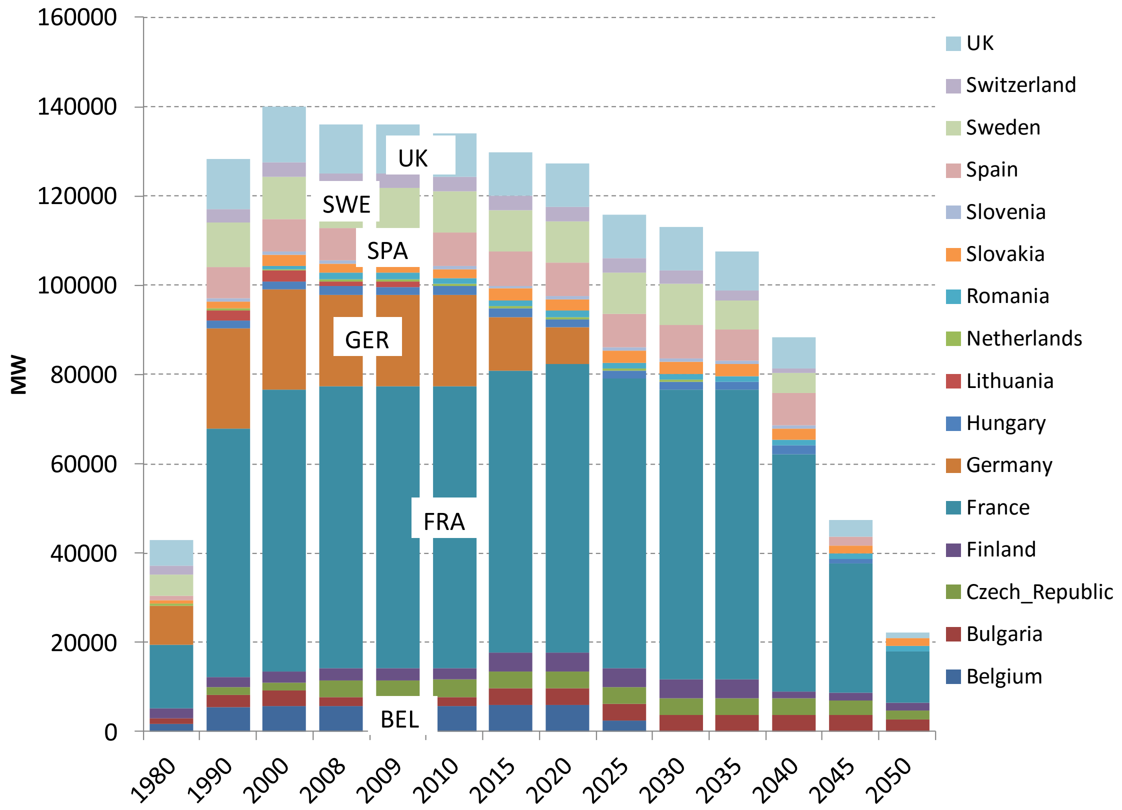


Figure 23. Estimated phase-out of existing nuclear power plants based on age (assumed technical lifetime of 60 years) or policy (in Germany). Source: EURELECTRIC, Chalmers Power Plant Database.

Costs of nuclear power

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

According to a recent WEC study (WEC 2013), current overall generation cost estimates for new nuclear power are in the range of 75–115 €/MWh electricity produced, depending on the region studied.[8] The median value lies at the lower end of that interval. The same source estimates

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

corresponding costs for onshore wind power of 40–150 €/MWh, depending on the region, with a median value of around 60 €/MWh. New natural gas power lies in the interval of 45– 110 €/MWh, with a median value of 50 €/MWh. Thus, in this context, new nuclear power is seemingly less profitable than new wind power or new natural gas-fired combined cycle schemes (CCGT), at least when comparing the median cost estimates. The Nordic Energy Technology Perspectives project conducted by the IEA has a somewhat more optimistic view of the overall generation costs of nuclear power. In that study, approximately 50 €/MWh was assumed as the representative levelised cost of electricity for new nuclear power plants (IEA, 2013).[9] As a comparison, the same study estimated the costs of new onshore wind power to be in the interval of 50–100 €/MWh, depending on the region and wind availability. Wind-power generation costs are, however, assumed to decline over time due to technological developments (this is not assumed for nuclear power). Electricity generated from new CCGT is estimated to cost approximately 50 €/MWh, with a tendency for the price to increase over time due to increased gas prices. Thus, in contrast to the former estimates made by WEC, the IEA study assumes relatively strong competitiveness for nuclear power in relation to other technologies.

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

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

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

GDP as a driving force for GHG emissions and energy consumption

The economic development, i.e. the development of the GDP, is yet another important external factor when analysing the development of the electricity and energy systems. The economic crisis in 2008 meant not only a downturn for the European (and the global) economy, but also a significant reduction of the rate of GDP growth in the EU's prognoses compared with the prognoses before the crisis. A substantially slower economic development will contribute to a continued reduction of the demand for energy, and also to a reduction of the emissions of greenhouse gases, thereby markedly improving the changes that the EU's energy and climate targets will be reached.

GDP – Its historical and future development

The GDP has increased approximately 45% in EU 28 during 1990-2013. The growth has mostly been 2-3% per year in this period, with two clear exceptions. In the early 90s the GDP fell in the new Member States, as a result of the collapse of the Soviet Union and the economic recession in Eastern Europe. The other exception is the economic crisis in recent years, with a pronounced dip in the GDP in 2008-2009. After this period we have seen a recovery to some degree, but the economy is still weak. Since 2008 the average GDP growth has been close to 0%/year.

The GDP in the new Member States has, after the downturn in the early 90s, had a better development than the average in EU 28 (Figure 24). If we look at the Swedish GDP development, it has, since the early 90s, been stronger than the average for the EU, particularly during the years following the economic crisis.

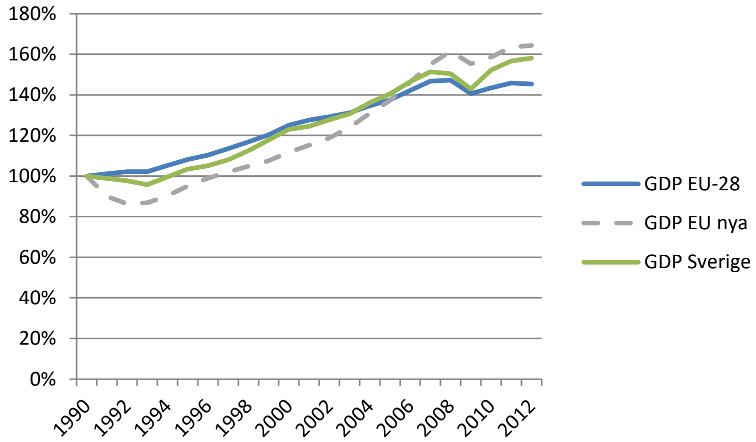


Figure 24. The development of the GDP in Sweden ("GDP Sverige"), EU 28, and the new Member States ("GDP EU nya"), during 1990-2012. The figure illustrates the percentage development relative the levels in 1990. (The GDP development for EU 15, representing 93 % of the EU's GDP, resembles that for EU 28). Source: Worldbank 2014.

The economic crisis has also had an impact on the EU's prognoses for the future GDP development. The prognoses from before year 2008 forecasted an average GDP growth up to year 2030 by approximately 2.2%/year in the union as a whole (EC, 2007). This was also the actual GDP growth before the economic crisis. The prognoses produced in the work with the EU Energy Roadmap 2050 (EC, 2011b), published in year 2011, present a significantly lower average GDP growth for the period 2005-2030 of 1.6-1.7%/year, whereas the EU prognoses today indicate an average GDP growth of only 1.4%/year for the same period (EC, 2013b).

The resulting difference in GDP by year 2030 between the most recent prognosis and the prognosis from 2007, i.e. before the economic crisis, is considerable. The prognosis from year 2007 ends up at no less than 3 000 billion EURO above the recent prognosis, which equals one fourth of the current GDP. (Figure 25, left panel illustrates the resulting percentage difference between the prognoses).

The development of the value added in the industry is a component in the prognosis calculations and, as illustrated by Figure 25, right panel, the differences between the different prognoses are even bigger for the value added.

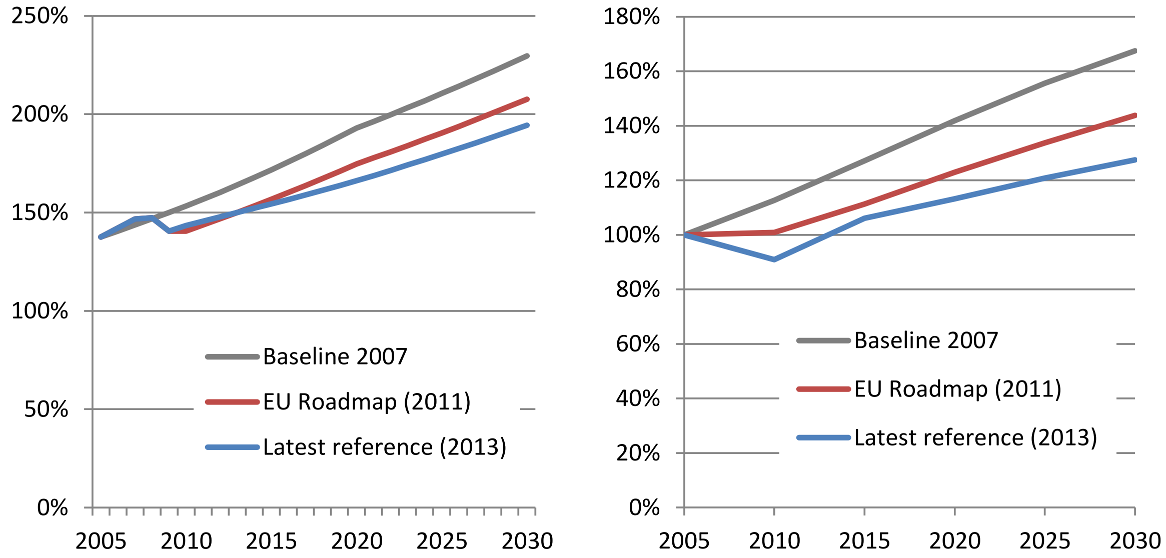


Figure 25. Three different prognoses for the development of the GDP (left panel) and the industry's value added (right panel,) in the EU 28, up to year 2030. The prognoses are from 2007, 2011 and 2013. The figures illustrate the percentage development relative the levels in year 1990 and in year 2005 respectively. Sources: EC 2007, EC 2011b, EC 2013b.

The relation between GDP development, energy use and greenhouse gas emissions

These large differences in the GDP prognoses will of course affect the prognosis for the energy demand. A slower economic development means a lower demand for energy (and thereby a lower use of primary energy). There is also a connection, even if more indirect, between GDP development and greenhouse gas emissions.

But, there is no direct proportionality between the economic development, and energy use and greenhouse gas respectively. Figure 26 illustrates the historical development of GDP, primary energy use and greenhouse gas emissions in EU 28 (left panel) and in Sweden (right panel). These figures make it obvious that the development of energy use and greenhouse gas emissions is decoupled from the GDP development.

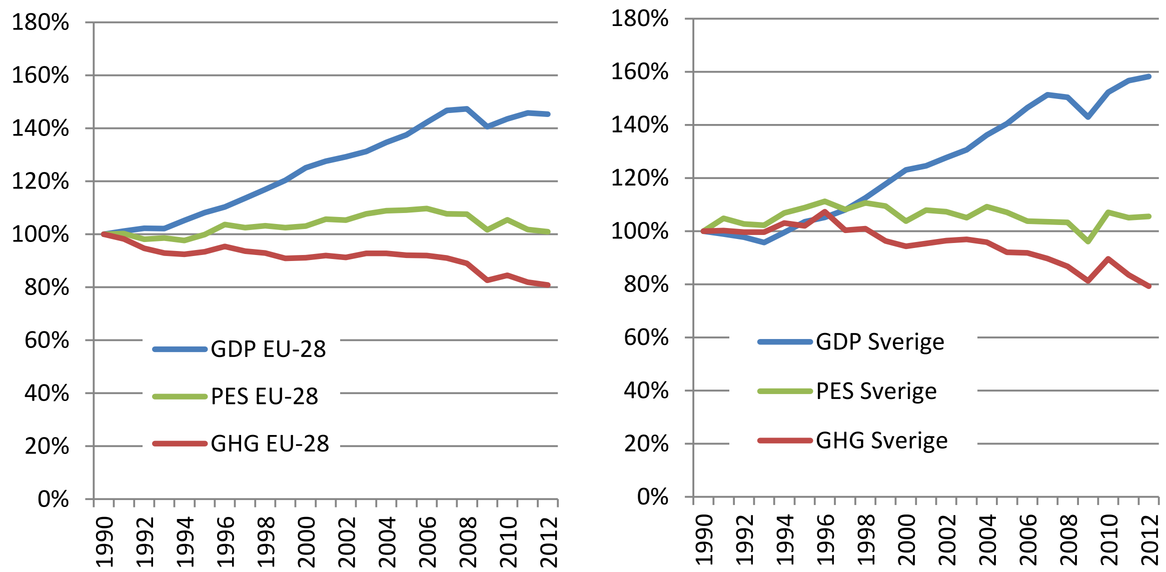


Figure 26. The development of GDP, primary energy use and greenhouse gas emissions in EU 28 (left panel) and Sweden (right panel, Sverige=Sweden) during 1990-2012. The figures show the percentage development relative the levels in year 1990. Sources: World bank 2014, EEA 2014a, Eurostat 2015.

But, despite GDP development being decoupled from energy and emissions, there are clear connections between them, and several different indicators are used to analyse and prognosticate how the relations between GDP and energy, and GDP and emissions influence the development. We have used a couple of these indicators in our analysis below.

Most well-established is the indicator *energy intensity* which describes the relation between the total (primary) energy use and the GDP, and which works as a measure of how efficiently the energy is used in the economy.

Similarly, indicators for *"emission intensity"* can be calculated, i.e. the amount of emissions of one or several agents per GDP unit. The EU includes the indicator *"CO_2-emission intensity"* in the result report for their energy scenarios. Also, EEA uses a relationship between the *yearly changes* of the GDP and the *yearly changes* of the greenhouse gas emissions (EEA 2014b). We have made use of both these emission indicators in our analyses.

Energy intensity and carbon dioxide emission intensity

The energy intensity changes with the technical and structural development in different sectors of the society, and with the implemented energy and environmental policies. It has changed in a very positive direction in the EU. Since year 1990 it has decreased by 30%, with an even yearly distribution (See Figure 27). In other words; as compared to the GDP we have seen a 30% energy efficiency improvement between year 1990 and year 2012. If we extrapolate the historical development, the energy intensity will have declined by about 50% by year 2030, and by about 65% by year 2050, compared to the level in year 1990. (These levels of energy intensity by year 2030 and year 2050 are also confirmed by the results in the EU's most recent energy scenarios (EC 2011, EC 2013)).

Even if the decrease in energy intensity means that the decoupling of GDP and energy use continues, using the energy intensity as an indicator, we can still prognosticate the development with quite a good precision. Continuously less energy is used per GDP unit, and the rate of this decline is relatively consistent over time, even if a bit higher in periods of economic growth compared to periods of recession. Some sectors of the economy are more affected than others, but energy intensity is a good general benchmark.

In the same way, emission intensities can be reported and extrapolated. The coupling of emissions to GDP should be considered as a bit more "indirect" and complex compared to energy, but still, as an example, the development of the emission intensity for carbon dioxide in EU 28 is quite similar to the development for energy intensity, as can be seen in Figure 27.

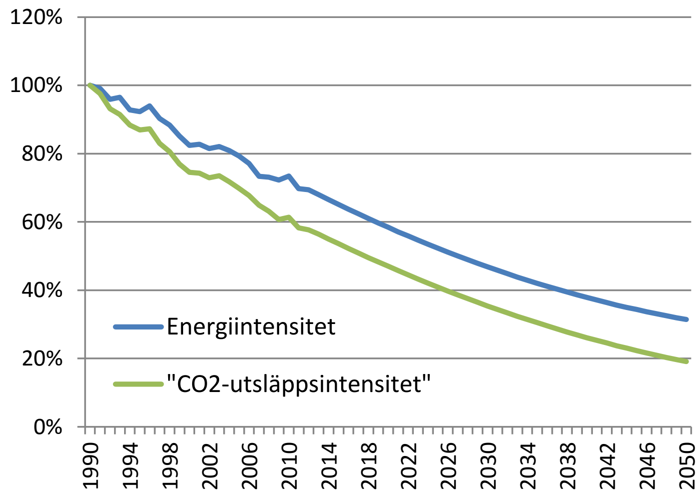


Figure 27. The development of energy intensity ("Energiintensitet") and carbon dioxide emission intensity ("CO2-utsläppsintensitet") in EU 28. The figures for 1990-2012 are based on statistical data whereas the figures for 2013-2050 are extrapolations. The figure illustrates the percentage development relative to the levels 1990. Source: NEPP 2015a.

The development of energy use related to different development of GDP

Figure 26, left panel, shows the use of primary energy in the EU for the period 1990-2012. Before the economic crisis the use of primary energy increased and after it has decreased. The energy scenarios presented by the EU before the crisis, e.g. Baseline 2007 (EC, 2007) are based on an assumed strong economic growth (a GDP growth of app. 2.2%/year) for the full period 1990-2030, and they consequently also indicate a continued increase of primary energy use all the way up to year 2030 (See Figure 28). As the energy intensity declines (see Figure 27) the increase of primary energy use will flatten out in Baseline 2007, and between year 2020 and year 2030 the increase is relatively small.

The EU's latest reference case from year 2013 (EC 2013b) is based on a much slower economic growth after year 2005, corresponding to a yearly GDP growth by approximately 1.5%. As a consequence, the primary energy use is at a considerably lower level in this reference case compared to Baseline 2007. But, as Figure 26, left panel, shows, since year 2008 we have had a zero growth in the EU, with a resulting even lower use of primary energy (11% lower in 2012) compared to the latest reference case. We are hence already more than half way towards reaching the 20% target for 2020.

The difference between Baseline 2007 and the latest reference case – or between Baseline 2007 and the actual development – cannot solely be explained by the slower GDP growth. Increased investments in efficiency measures on the user side (e.g. increasingly more efficient vehicles) as well as in the transformation chain (e.g. larger share of wind and solar power) also have contributed to lowering the primary energy use compared to Baseline 2007. Many of these investments are initiated by implemented energy and environmental policies after year 2007. Of the 11% reduction up to year 2012, a bit more than half (6-7%) can be related to the reduction in GDP, and a bit less than half (4-5 %) to the measures taken, according to our analysis.

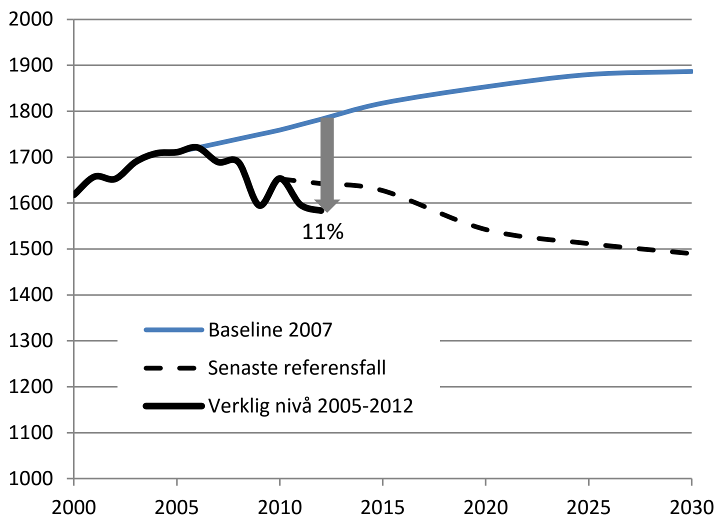


Figure 28. The development of the primary energy use; the actual development ("Verklig nivå 2005-2012") as derived from statistical data and the development as outlined in Baseline 2007 and the latest EU/Primes Reference case3 ("Senaste referensfall"). Sources: Eurostat 2015, EC 2007.

The level of primary energy use in Baseline 2007 is also used as the reference level for the EU's energy efficiency optimisation targets. But, Baseline 2007 was, as already mentioned, established before the economic crisis. The question is then, how much lower would the reference levels for the efficiency targets for 2020 and 2030 be, if Baseline 2007 is adjusted with the slower GDP growth now seen in the EU's prognoses[10]. Would the effect from the GDP up to year 2020 be of the same magnitude as the effect we have seen up to year 2012? Yes, almost of the same size! The reference level for year 2020 would then be reduced by 11%, and for year 2030 by 13%! This would mean that more than half of the efficiency target of 20% for year 2020 and almost half of the efficiency target of 27% for year 2030 is accomplished, just by this GDP adjustment (See Figure 29). Remaining is then a minor part, 9 and 14% respectively, which must be achieved through "policy triggered" efficiency measures (i.e. measures needed in addition to what is done in Baseline 2007).

[10] According to our historical analysis (NEPP 2014b) and the EU's scenarios, different rates of GDP growth will, as already mentioned, in a longer term affect the development of the energy intensity. With a slower GDP development, also the decline in the energy intensity will be slower compared to a more rapid development of the GDP, but the differences are small. When adjusting Baseline 2007 we have taken this into consideration (to avoid too big a correction).

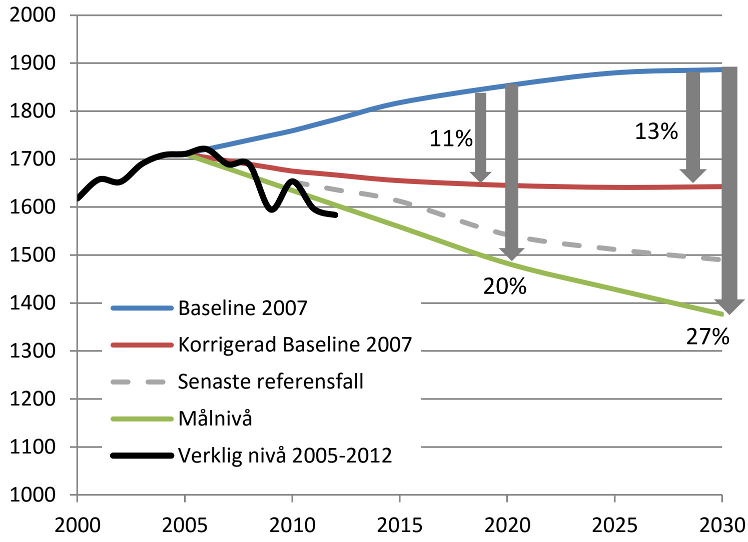


Figure 29. The development of primary energy use in EU 28; the development as seen in Baseline 2007, the development according to the EU's efficiency targets ("Målnivå") and the GDP-adjusted Baseline 2007 from our analysis ("Korrigerad Baseline 2007"). As reference we have also included the statistics-based actual development up to 2012 ("Verklig nivå 2005-2012") and the latest EU/Primes Reference case3 ("Senaste referensfall"). Sources: Eurostat 2014, EC 2007, NEPP 2015a.

At the same time, the EU is hoping for a GDP development better than the one prognosticated. If a faster GDP growth becomes reality, it will stimulate also the primary energy use to grow. And with a maintained target level this will result in increased demands for the implementation of a larger set of "policy triggered" efficiency measures than that corresponding to the mentioned 9 respective 14%. And with this raised demand for measures it will of course be more challenging to reach the targets. With a strong development of GDP in the EU up to 2030, equalling that in Baseline 2007, the full target of 20% efficiency improvement must be accomplished with "policy triggered" efficiency measures. It will be particularly challenging if future investments in efficiency improvements will not have a better effect than those already implemented have had.

The EU has come to the conclusion that the decline in the GDP growth is of minor significance, in spite of their own analyses pointing in the opposite direction

In the documents from July 2014 that has formed the basis for the decisions about the year 2030 targets (EC 2014i), the European Commission states that the economic crisis and the ongoing slower economic development is not the main reason behind the decline in primary energy use. Their view is rather that the increased investments in policy triggered efficiency measures is the main reason and that this explains 50 – 65% of the reduction in primary energy use (relative Baseline 2007) for the period 2008-2012 and further up to year 2020. This is, as we see it, not a correct conclusion, and the documents and analyses the commission is referring to are not supporting their view. On the contrary, the documents show that the main reasons are the stagnation in GDP growth we have seen since the economic crisis in year 2008, and the downward revision of the GDP prognosis made after 2008, which rather is backing up our conclusions. How the EU Commission still can come to the opposite conclusion can be explained, we think, by a couple of simple methodology and interpretation mistakes done when working with the analysis results they have used as a basis for their conclusion. (See the summary below for a more detailed description of the analyses and calculations forming the basis for the EU Commission's conclusion).

In total, it is *quite* a *remarkable conclusion* delivered by the EU Commission, and with this conclusion as a foundation they argue that policy triggered measures – which have been very successful historically – also will result in a continued and large decrease in primary energy use up to year 2020 and year 2030. Of course, this argumentation is basically laudable, maybe also harmless, as long as the consequence is not a battery of measures that drives costs beyond what is reasonable. More serious is however, that the EU Commission – by reducing the importance of the GDP for the development of the energy use – will not be prepared to intensify the investments in policy triggered measures, in case of a future economic recovery and strong GDP growth.

Through their argumentation, the EU Commission also neglects another discussion that should be taken sooner rather than later. With a continued slow GDP growth, and with a true enthusiasm for a real energy efficiency improvement, it would be reasonable to discuss whether Baseline 2007 should be reconsidered as a reference level for the efficiency improvement target (or if the target for 2030 should be sharpened). In the EU documents from July 2014 that we are referring to above, there is no sign of challenging the Baseline 2007 as the reference level in the near future.

Review of the supporting material forming the basis for the European Commission’s conclusions (Source: EC 2014i)

In the documents forming the basis for their decisions on the year 2030 targets, the EU Commission states that the economic crisis and the continued slow economic development cannot explain more than a third of the primary energy decline (relative Baseline 2007). Their view is rather that the increased efforts in policy triggered efficiency measures is the reason behind more than half (almost two thirds) of the decrease in primary energy (relative Baseline 2007) for the period 2008-2012 and further up to year 2020. The slower economic growth is thus, according to them, of minor importance, historically as well as in the future (up to year 2020 and year 2030). This is, as we see it, an incorrect conclusion with no support in the documents and analyses the Commission base their conclusion on.

In the EU documents there are three types of analyses presented, which are forming the basis for the EU Commission’s conclusion:

- A decomposition analysis of the factors behind the decline in the use of primary energy after the economic crisis. The analysis describes the development during the five years from 2008 to 2012 (Fraunhofer, 2014b).
- Model analyses with several models, e.g. the PRIMES model and several Fraunhofer models, describing the development with and without investments in policy triggered measures. These analyses focus on the future development, but some of them also look back a couple of years.
- Model analyses with the PRIMES model, showing how the primary energy use is influenced by the future GDP development.

In the historical decomposition analysis they have investigated the factors behind the decline in primary energy use during the period 2008-2012. This study very clearly shows that the decrease in (economic) activity is the totally dominant reason behind the decline, precisely the opposite of what the EU Commission says in their conclusion. When it comes to the increased investments in policy triggered efficiency improvement, this analysis shows that it has been of minor importance.

It is, therefore, *a very remarkable conclusion* drawn by the EU Commission, particularly since they explicitly refer to the results from this decomposition study when they motivate their conclusion. As we see it, they should rather have come to the opposite conclusion; that the downturn in economic activity has been the dominating reason behind the decline in primary energy, not the efficiency efforts.

Our reasoning about how the Commission might have come to this (as we see it erroneous) conclusion, is that they simply have made a classical computational mistake. When they calculate how much of the primary energy decrease (relative baseline 2007) that is due to an *increased* effort in efficiency improvements during 2008-2012, they have included *all* efficiency improvement. This is not correct, since efficiency improvements have been made even before 2008. The difference is large, and becomes even larger when we rectify further calculation mistakes in the Commission’s documents. As a matter of fact, they have also calculated the *yearly* savings in an incorrect way, when they have transformed the results from the decomposition study. In the study, the period 2008-2012 is analysed and they refer to this as a period of five years (and not four, which possibly would have been more logical). Moreover, as a “control period” they have also analysed the period 2000-2012, which they see as twelve years. This might seem illogical (the longer period should maybe be seen as spanning over 13 years), but that is not the case. It is obvious from the study how it is done. But in the processing of the study results as described in the EU documents, they calculate with only four years for the period 2008-2012. The consequence of this miscalculation is too high figures when transforming the total value for efficiency improvement 2008-2012 to yearly values. In the same way, they have ended up with erroneous numbers in their calculation of the yearly efficiency improvement during the years before year 2008 (2000-2008). They have calculated on eight years, but according to the study it should have been seven years (12-5=7).

Figure 30 illustrates the impact these two deviations have on the outcome. The two bars to the left are from the EU document (ref), and based on these figures they have stated that *all* of the efficiency improvements during the period 2008-2012 can be referred to the increased policy triggered measures implemented by the EU. The two bars to the right show the correct result from the study, and the green arrow represents the efficiency improvement we think should be attributed to an *increased* policy triggered efficiency improvement activity.

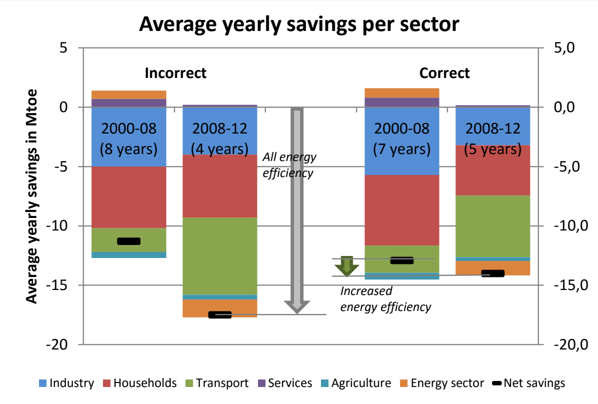


Figure 30. The yearly energy efficiency improvement per sector, in EU, for the periods 2000-2008 and 2008-2012. The supporting material for the figure is obtained from EC 2014i, and the figure is explained in the text above it.

A rough estimate helps us to understand how the difference between the conclusions can be so big. We use figures for the efficiency improvement from figure 30 and figures for the decline in primary energy from figure 29. The decline in primary energy that should be used is the decrease from year 2007 (N.B., the year before 2008) to year 2012 (for both years it is the decrease relative Baseline 2007). Looking at figure 29, we can see that the primary energy use in year 2007 was approximately 40 Mtoe lower than Baseline 2007, and in year 2012 it was 200 Mtoe lower. Thus, the difference is 160 Mtoe.

For the efficiency improvement, we have calculated with the figure for *all* efficiency improvement used in the EU document (app. 18 Mtoe/year, symbolised by the grey arrow in the figure), as well as with the figure for the *increase* in efficiency improvement only, according to the true result from the study (app. 1 Mtoe/year), symbolised by the green arrow). The aggregated efficiency improvement for the five years 2008 - 2012, calculated as in the EU document, ends up at 83 Mtoe (1x11 + 4x18). If we, instead, sum up using the figures for the *increase* of the efficiency improvement according to the true result from the study, the outcome is 5 Mtoe (5x1)

If we use these two sums to calculate how big part of the decrease in primary energy that is due to efficiency improvement measures we will get 52 % (83/160 for 2012), calculated as in the EU document – which is incorrect – and 3 % (5/160 for 2012) calculated with the true figures from the study. The results are quite different, and so are of course the conclusions that can be drawn from these results.

So far, the historical development. When estimating the future development, at least up to year 2020, again the decomposition study is used as one of the supporting documents in the EU document. They make what they call an extrapolation of their (erroneous) result for 2011 - 2012 (and also 2013) and furthermore, they state that the resulting trend is true all the way up to year 2020. Based on this extrapolation they mean that the conclusion can be drawn that the importance of the policy triggered efficiency improvements measures will *increase* – because this is supported by the extrapolation they have made – and explain no less than two thirds of the decline in primary energy by year 2020 (an increase from 52 % in year 2012). But, we cannot find any concrete facts at all in the analyses and documents they refer to, that motivates this kind of extrapolation, and since it also is based on the wrong starting point (2011-2012) we find no reason for having great faith in the correctness of this approach.

Why then, has this extrapolation not been scrutinized and criticised? One of the reasons could be that the model analyses performed – and they are many – support the development that the extrapolation shows. As a matter of fact, the model analyses are very clear on two points; firstly, increased investments in efficiency improvement measures will result in enhanced efficiency, secondly, although a slower economic growth will result in a decreased primary energy use, this decrease is limited (unless the decrease in GDP is very big). One thing that is *not* obvious from the model analyses though, is what the reasons are behind the big dip in primary energy between year 2008 and year 2012. Rather, they have just used the actual figures for the historical years when running the models, without explaining how they differ from previous model analyses, e.g. Baseline 2007. The model creators should not be blamed for this, since that was probably not something they were asked to do, but in this specific case it would have been useful if an explanation of the historical development also had been included as a result of the model analyses.

We certainly do not see any reason to question the model results from the performed analyses. But, if these model results are used in the wrong context (e.g. with erroneous assumptions about what factors are behind the historical development) the insights from the model results might partly be interpreted in a way they are not suited for.

When the model results show a limited effect on the primary energy use from a change in GDP, this is an important clue to the analysis of the *future* development. They have modelled a GDP growth of, on average, 1.5%/year up to year 2020 and year 2030, and then varied the analyses using 1.2%/year and 1.9%/year respectively. Thus, the difference between the lowest and the highest GDP development is 0.7%/year and this results in a difference in total primary energy use of 3% by year 2020. In the model analyses developed for the EU's Energy Roadmap a couple of years ago, the result for the same GDP difference was a difference in primary energy of approximately 4% by year 2020. These model results seem reasonable, and we have also used them in our analysis of the difference between Baseline 2007 and the EU's most recent reference case (from year 2013), which is illustrated in figure 28 above. In our analysis we explain about 4% of the decrease between year 2010 and year 2020 by the difference in GDP of 0.7%/year between the two scenarios for this ten-year period (Between year 2020 and year 2030, the GDP related decline in primary energy in figure 28 is approximately 2%, since the GDP difference is less during this ten-year period).

It is also possible to use these model results for the historical analysis, even if this is not done by the model creators. Let us make a rough estimate for the period 2008-2012. The model results show a relatively limited decrease in primary energy by 3-4% in ten years if the GDP declines by 0.7%/year. But for the period 2008-2012 the difference in the GDP between Baseline 2007 and the actual development was on average no less than 2.4 %/year. The resulting decrease in primary energy would be 6-7% for the five-year period 2008-2012 (corresponding to 11-14% if it had been a ten-year period). In energy terms this equals 105 – 120 Mtoe, which can be compared to the total decline in primary energy the same period by 160 Mtoe. Thus, this rough estimate supports our – and the decomposition study's – view that the economic downturn during 2008 – 2012 can explain more than half of the decline in primary energy use.

In summary, we can conclude that we are not able to find any support for the conclusion drawn by the EU Commission saying that *the main reason* behind the decline in primary energy use is the increased investments in policy triggered measures, neither in the EU's documents and analyses, nor in our own analyses. This is particularly true for the historical development, but also for their role in the whole period 2005 – 2020 (and also up to year 2030). The main reasons are rather the decline in GDP growth we have seen since the economic crisis in year 2008, and the downward correction of the future prognosis the EU now has made. This is proved by the analyses presented in the EU documents as well as our own analysis. That the EU Commission still can draw the opposite conclusion might, we think, be explained by a couple of simple methodology and interpretation mistakes when handling the analysis results they have used in their conclusion.

The development of greenhouse gases emissions with different GDP development

The emissions of greenhouse gases have decreased by approximately 1100 $MtCO_2e$/year, equalling 19.2%, in the EU during 1990-2012 (See Figure 26 above), and now they amount to 4 500 $MtCO_2e$/year. This is a significant reduction and it means that the EU already today (2012) is close to the 20% target for year 2020.

The reduction of carbon dioxide emissions is largest and make up a bit more than 700 $MtCO_2e$/year, but the decrease of methane and nitrous oxide emissions are also considerable, each equalling approximately 200 $MtCO_2e$/year. But, as a percentage, the methane and nitrous oxide emissions have been reduced more than twice as much as the carbon dioxide emissions.

There is, as we have seen above, a connection between GDP development and the development of greenhouse gas emissions. Of the various greenhouse gases, carbon dioxide has the most obvious connection to GDP. Figure 31 shows the development of carbon dioxide emissions in EU 28 for the period 1990-2012. For several sectors we can clearly see a reduction in the emissions when the economy has been week; in the early 90s and from year 2008 and onwards. We can also see the effects of the economic recovery between these periods.

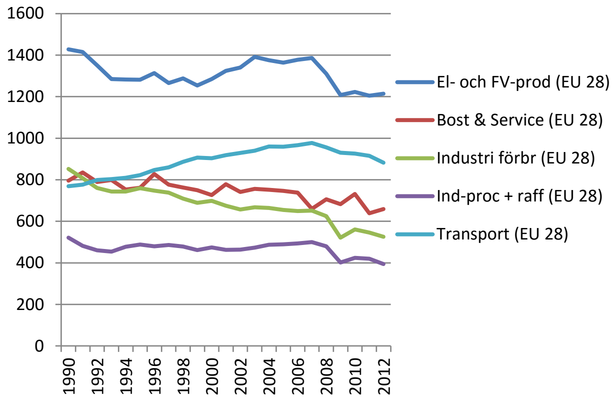


Figure 31. The development of the carbon dioxide emissions in EU 28 by sector. "El- och FV-prod" = Electricity and District heat production; "Bost & Service" = Residential and Commercial sectors" "Industri förbr" = Industry, non-process use; "Ind-proc + raff" = Industrial processes and refineries. Source: EEA 2014a.

According to the EU's environmental agency EEA, approximately one third of the decrease of the emissions of greenhouse gases in the EU since year 1990 can be explained by changes in the economy (GDP), as we have seen above. The impact from the economy on *the carbon dioxide emissions* is even larger, whereas the GDP's impact on the development of the methane emissions is less than one third. The EEA is basing their estimations on three different types of studies. The first study is a decomposition study aiming at analysing the factors behind the reduction of *carbon dioxide emissions* from incineration of fossil fuels in the EU since year 1990. In this study they used a set of indicators, e.g. emission indicators. The second study is a regression analysis study, wherein direction coefficients (elasticities) are calculated for linear expression of the relation between the yearly changes of the greenhouse gas emissions in the EU, and the yearly changes of GDP. In the third study, r-square values are calculated to mathematically verify that a correlation really exists, and to estimate how strong this correlation is.

Figure 32, left panel, shows the yearly changes of the GDP and the emissions of greenhouse gases for EU 28 as presented by the EEA. The two curves show obvious similarities, but there are also distinct differences. The connection is, according to the EEA, not at all hundred percent, but their studies show a relatively strong correlation.

With their three studies as a basis, the EEA estimates that approximately one third of the decline in the emissions of greenhouse gases is connected to the changes in GDP during the period 1990-2012. They also state that the correlation is of different strength for different sectors, and that the decrease in emissions has been particularly large in the two periods of economic downturn; the early

90s in Eastern Europe and the economic crisis in 2008 and the following years, since the GDP slowdown has been particularly pronounced then.

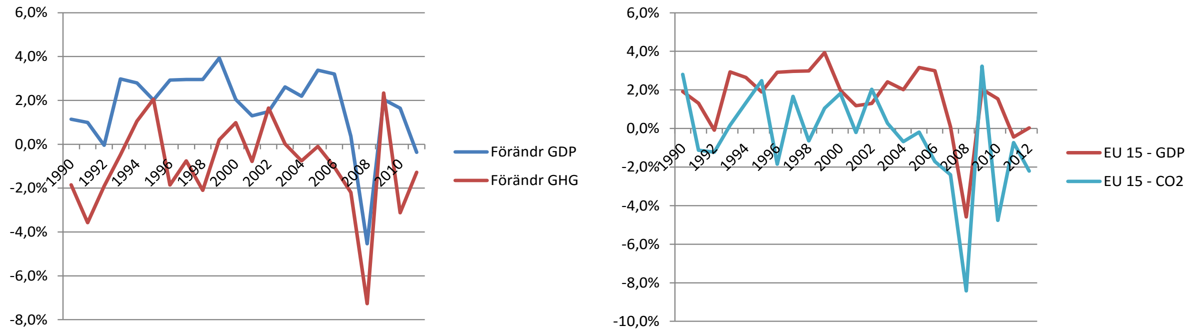


Figure 32. The yearly change of GDP ("Förändr GDP") and greenhouse gas emissions ("Förändr GHG") in EU 28 (left panel) and the yearly change of GDP and the carbon dioxide emissions in EU 15 (right panel) during the period 1990 – 2012. Sources: EEA 2014a, Worldbank 2015.

At the same time, our own analysis shows that the correlation can be stronger for specific greenhouse gases, mainly carbon dioxide and nitrous oxide, and weaker for others, e.g. methane. There are also differences in the correlations between old and new Member States. For the old Member States the correlation between the yearly changes of GDP and the yearly changes of carbon dioxide emissions is really strong (see Figure 32, right panel). Also the future development of greenhouse gas emissions in the EU will be influenced by how strong the economic development will be. As we have seen, a third of the decline in the emissions of greenhouse gases by 19% up to year 2012 can be attributed to the recession in the economy. In the same way, a continued slow growth up to year 2030 will result in lower levels of emissions compared to the emissions with a faster economic development.

Most marked is the impact from GDP development on carbon dioxide emissions. Figure 33 below shows the development of carbon dioxide emissions according to the EU´s latest reference scenario (EC, 2013). This scenario is based on a GDP growth of 1.5%/year on average from year 2010 to year 2030. Emissions will during this period be reduced by 22%. If we compare the level of the emissions in this reference scenario to an alternative development with a GDP growth of 2.2% on average, the emission level will be 6% higher. If we also fully compensate for the decline in GDP during the economic crisis, and assume that the growth of the GDP up to year 2030 will include a full recovery from this decline, the level of emissions will be 12% higher than in the EU's latest reference scenario. This would mean that the reduction of the carbon dioxide emissions will stop at a few percent and we will end up way above the target of minus 40% by year 2030.

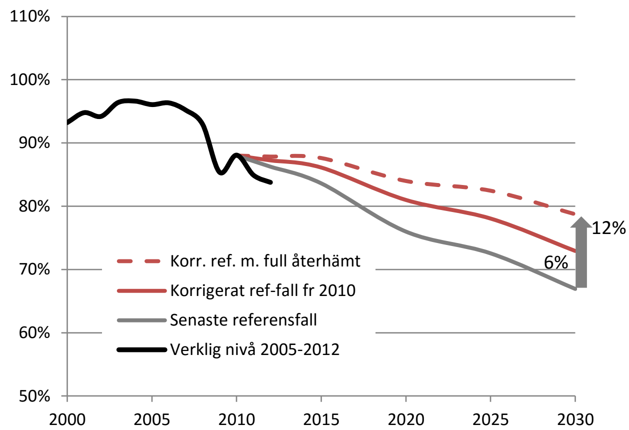
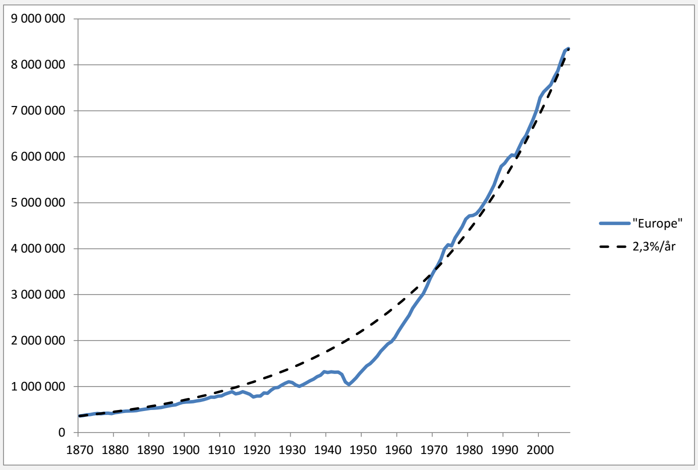


Figure 33. The development of the total carbon dioxide emissions in EU 28 up to year 2030. The figure shows the development as seen in the EU's latest reference case (EC, 2013) ("Senaste referensfall"), and the development with two alternative scenarios for GDP growth as described by NEPP ("Korrigerat ref-fall fr 2010" = Adjusted reference case from year 2010; "Korr. Ref. m. full återhämt" = Adjusted reference case from year 2010, including a fully compensation for the decline in GDP.)

The European economy has recovered from all economic crises and GDP downturns since 1870

Economic crises and large GDP downturns is not a new phenomenon. In the 20th century we had downturns in GDP equal to that during the worst year of the finance crisis (year 2009, when GDP dropped by 4.5%) several times. These were caused by the two World Wars and by the depression in the 30s. During the period 1970-2000, the GDP had negative growth figures at three different occasions. The European economy has recovered relatively fast after the World Wars and the depression in the 30s as well as after the three negative GDP periods 1970-2000. Therefore Europe has showed an average GDP growth since year 1870 of 2.2-2.3%/year (See the figure below). Since the end of Wold War II it has even averaged more than 3.3%/year.



Source: Maddison (2013)

If history repeats itself, it is reasonable to believe that Europe's economy again will take speed also after this latest economic crisis, and within a period of 10-20 years recover from the entire decline in GDP we have seen since year 2008. At least, the history justifies drawing up (alternative) scenarios that are based on the assumption that the European economy will go through a full recovery.

The target for renewables is not impacted to the same extent by the GDP development

The share of renewable energy has increased in EU for a long time. In year 1990 it was 6%, in year 2005 8-9% and in year 2012 it was 14%. All Member States have increased their share of renewables.

The target for renewables is a "proportion target", specifying the proportion of the renewables of the consumed energy on the end user side ("final energy consumption"). The numerator is the amount of renewable energy and the denominator is the amount of "final energy consumption". The proportion (share) will grow when the amount of renewable energy is increased, as well as when the amount of "final energy" is decreased. But, it's worth noticing that an increase of the numerator by one percent or a decrease of the denominator by one percent, will not result in an increase of the share of renewables by one percent, rather in an increase by a bit more than a tenth of a percent. The reason is that the target is a "proportion target" and mathematically the present share of approximately 14 % will give these results when changed.

For this reason, we can see that the share of renewables will only increase by a bit more than 1 % if the amount of "final energy" is reduced by 10% by year 2030 as a consequence of de stagnation of the economy. Neither has the historical decline in energy use after the economic crisis had any major influence on the increase of the share of renewables. The increase from 8-9% in year 2005 to 14% in year 2012, can largely be related to the large investments in renewables (the numerator has increased by 55%, from a bit less than 100 to 155 Mtoe of renewables, and the denominator has decreased by approximately 10%, from 1200 to 1100 Mtoe of “final energy”).

At the same time, it seems reasonable to believe that the investments in renewable energy (and the policy instruments that are stimulating those) also will be negatively impacted by economic stagnation. Then also the numerator in the formula will decrease in a time of economic downturn. But in our analysis of the historical development we cannot see this kind of connection between GDP development, the policy instruments and the investments in renewables. Our view is therefore that a slower economic growth mainly will have an impact on the denominator, but this impact is small, thereby saying that the possibility to reach the renewable target is to a limited extent influenced by how the GDP develops.

Summary of the importance of the GDP development for target attainment

The reasoning above is based on the historical analysis we have performed for 1990-2012 (which is mainly based on statistic material and analyses from the EEA, the European Commission and Eurostat), and some of the scenarios for the future development created by the EU.

We can conclude that the slower GDP development that the EU now prognosticates for the period up to year 2030 - compared to the EU’s prognoses before the economic crisis - will have a major impact on the likelihood to reach two of the three energy and climate targets for year 2030. The efficiency target will be significantly easier to reach, ”only” about 14% remains of the ”policy triggered” efficiency improvement targeted for year 2030. The greenhouse gas target is reduced by approximately a third. The renewable target is the least impacted, and might thereby be the target hardest to achieve. In parallel, the EU and its Member States have shown, particularly after year 2005, that they are ready to make far-reaching investments in renewables.

On the other hand, if the economic recovery in the EU turns out to be stronger, with a significant recovery followed by a continued strong growth measuring up to the EU’s prognoses before the economic crisis, the challenges in meeting the energy and climate targets for year 2030 will be considerably tougher. The efficiency target will be impacted most and will then become much harder to reach. Also the greenhouse gas target will be very hard to reach with a stronger economic development. The target for renewables is less impacted by the economic development, but is already challenging even with a slow economic development.

European electricity-system outlook

The existing generation-capacity stock

For more than two decades, investments in new power plants across Europe have predominantly been made in gas-fired plants and renewable electricity generation (see Figure 34). This is in clear contrast to the 1970s and 1980s when heavy investments were made in coal-fired and nuclear power. Furthermore, the capacity build-up in the last 10 years (2004-2014) has been dramatic from a historical perspective, with roughly twice as much investment in capacity as in the previous decades. This is mainly a result of the significant increase in renewable electricity-generation capacity, which has been spurred by different support schemes across Europe. Yet, for the RES technologies it should be kept in mind that the full-load hours, generally, are significantly fewer than for thermal power plants. Thus, on an energy basis the fraction of RES-based electricity supply is less pronounced than shown in Figure 34.

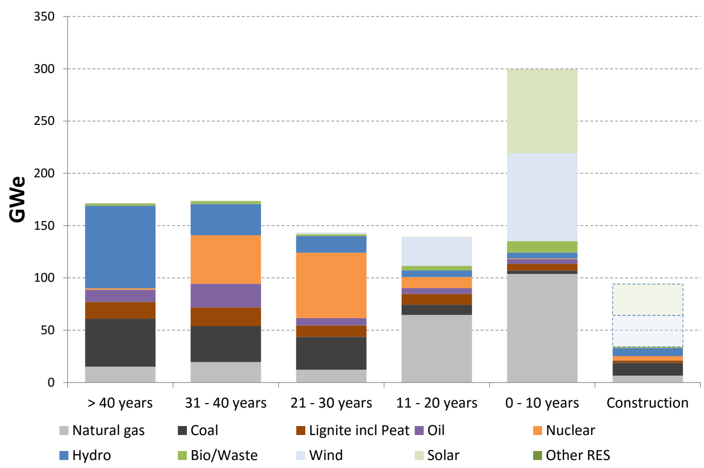


Figure 34. Age distribution of existing power plants in the EU-28. Solar power and wind power plants under construction are, in principal, not included in the database (Source: Chalmers Power Plant Database, status March 2014).

The geographical distribution, by fuel, of thermal power plants (> 1MW) currently in operation in the EU- 28, Norway, and Switzerland, is shown in Figure 35.

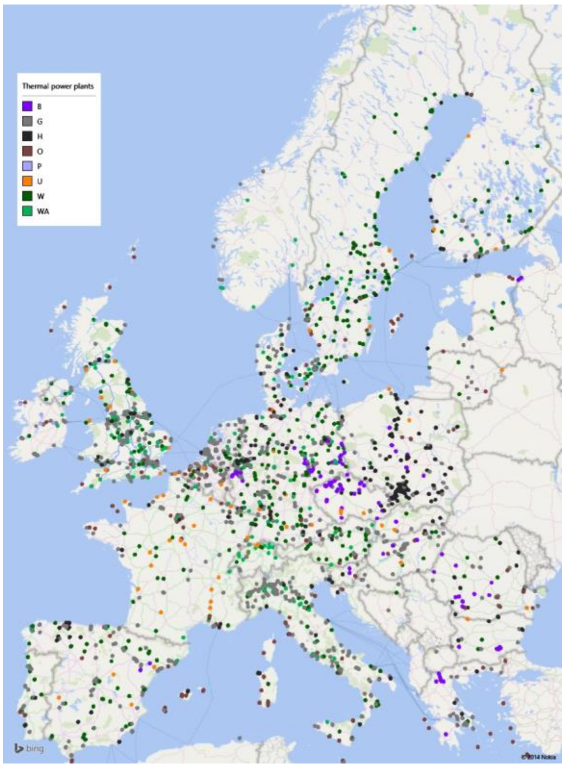


Figure 35. Distribution of thermal power plants in Europe as taken from the Chalmers Power Plant Database (B= lignite, G=gas, H=hard coal, O=oil, P=peat, U=nuclear, W=biomass and WA=waste incineration).

From Figure 34, it is evident that a large share of the thermal power plant fleet in Europe is of advanced vintage, i.e. approaching the end of its life time. This is true especially for the nuclear and solid-fuel power plants. Figure 36 further underlines this by showing, as a supplementary way to represent the age distribution, that approximately 30% of the existing (end of year 2014) capacity will be phased out due to aging by year 2030. Even if the technical lifetime of a power plant is largely plant-specific, the interval of 30–40 years is often referred to as a limit for thermal power plants (see for example the assumptions made by IEA/ Nordic Energy Research, 2013). For nuclear power, 50–60 years is typically mentioned as the potential limit for the technical lifetime. For wind and solar power we assume a total lifetime of 25 years in Figure 36.

Thus, large phase-outs due to age are likely to occur across Europe in the coming 10–20 years. Based on these somewhat rough lifetime assumptions, approximately half of the European thermal power plant capacity will be phased out due to aging before year 2030. Meanwhile, the expansion of variable renewable electricity is likely to proceed at a rapid pace, which raises questions concerning the future availability of thermal back-up capacity.

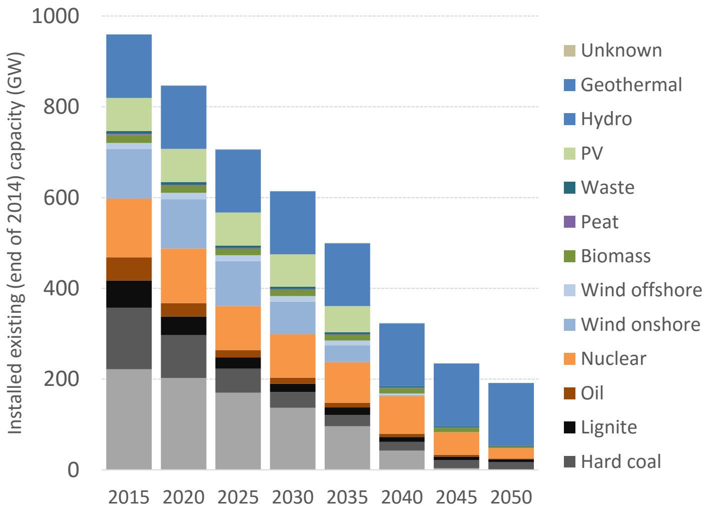


Figure 36. Phase-out of existing electricity-generation capacity in Europe (EU-28, Norway and Switzerland) due to aging (own assumptions on life-times of different power plants) and due to political decisions (e.g. nuclear phase-outs).

Based on data on commissioning year of every single power plant across the EU, we conclude that in the coming decades phase-out due to aging is likely to initiate substantial investments in new capacity. It is the aim of this study to further analyse the size of these investments and to quantify them in terms of capacity and number of power plants.

Key scenario assumptions

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

The four main scenarios are:

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

The assumptions as to electricity demand are given in Figure 37. Gross electricity demand is provided exogenously to the model (the ELIN model) and is therefore not a model result in itself. Since year 1990, electricity demand has increased steadily in the EU as a whole. During the global recession of 2008–2009 and the financial crisis in year 2011, electricity demand fell significantly (see Figure 37). Demand projections for the Reference scenario follow the model-based projection by the European Commission in their reference scenario (EC, 2013). Thus, electricity demand in year 2050 is around 30% higher than the current level. For the Climate Market scenario, we assume that demand partially follows that of the Powerchoices Reloaded study (Eurelectric, 2013). In that study (as in our Climate Market scenario), assumptions related to increased electrification in transportation, industry, and the heating market across the EU affect the long-term electricity demand. In the Green Policy scenario, we assume that the very large penetration of renewable electricity is facilitated by flexible and efficient electricity use. Thus, we assume that electricity demand is lower than in the Reference scenario, yet increasing compared to its current level. Finally, the Regional Policy scenario is characterised by ambitious end-use efficiency polices that keep demands for electricity and other final energy uses at relatively low levels.

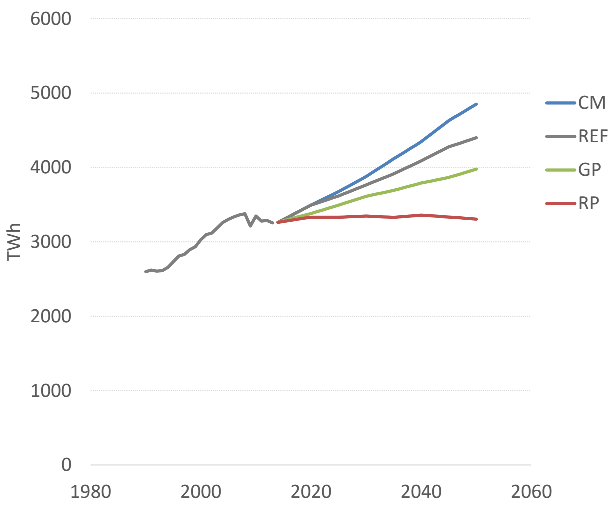


Figure 37. Assumptions made regarding gross electricity demands in the four main scenarios (Source for 1990-2013: Eurostat).

All the scenarios have the same renewable electricity generation (RES-E) shares of gross electricity demand until year 2020. These shares follow the Member State's projections reported in the National Renewable Allocation Plans (NREAPs) in year 2010. After year 2020, only the Reference scenario and the Regional Policy scenario assume continued and nationally defined targets for RES-E. The RES-E shares of total gross electricity demand are shown in Figure 38. For comparison, the model-assessed reference projection presented by the European Commission in December 2013 projects a RES-E share in the EU-28 as a whole of around 50% of the gross electricity demand by year 2050. This accords with our assumption for the Reference scenario (Figure 38). The EC Roadmap "High efficiency" scenario, which is the inspiration for our Regional Policy scenario, projects a RES-E share of gross electricity demand of approximately 65% by year 2050. This is in close agreement with the assumptions we make for the Regional Policy scenario. There are no RES-E targets post-2020 in the Climate Market scenario. In the Green Policy scenario, we apply a common European tradable certificate scheme for stimulating RES-E investments post 2020 with the aim of reaching a penetration of more than 95% of gross demand in 2050.

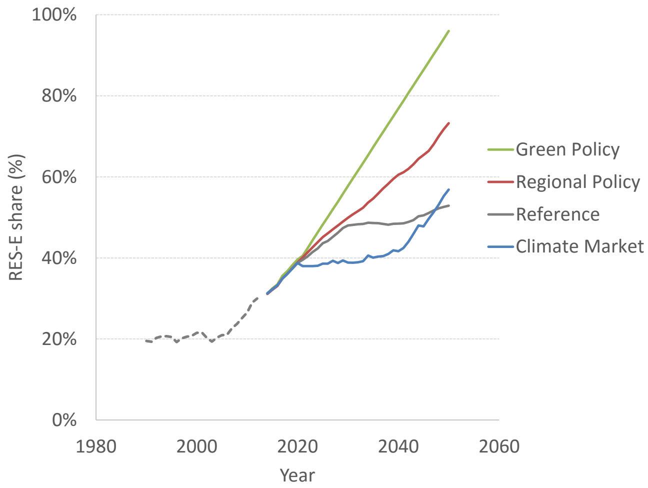


Figure 38. Share of renewable electricity (RES-E) generation of gross electricity demand in all four scenarios.

Scenario results - Electricity supply

In this section, we summarize the model results on electricity generation and capacity for all four scenarios. Even though the model generates output for each single country, we focus solely on aggregated European results.

Reference scenario

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

In *Figure 39,* we present the model results on the development of the European electricity generation and capacity based on the Reference scenario. The left panel shows total production by fuel and source for 1990–2013 based on statistical data, and for 2014–2050 based on the ELIN model results. The right panel shows the total installed capacity, based also on ELIN model results, between year 2014 and year 2050 sub- divided into five main groups of generation capacity. Owing to the RES-E target, which increases the share of renewable electricity to around 50% of the total gross electricity demand by year 2050 in the EU-27, Norway, and Switzerland taken as a whole, the use of wind, solar and biomass grows substantially over time. CCS (coal) enters significantly into the production system post-2030. New investments in conventional fossil-fuelled electricity generation mainly involve natural gas (CCGT schemes and gas turbines). New nuclear power is profitable around 2035 in this scenario when wholesale electricity prices (see forthcoming section) are sufficient to cover the assumed total generation costs of nuclear power, which are then approximately 50-55 €/MWh (assuming 4200 EUR/kW in investment cost, technical/economical lifetime of 60 years and 5% real discount rate).

We may also conclude that the significant expansion of variable renewable electricity (vRES) entails a dramatic increase in total capacity. This is explained by the fact that vRES technologies generally have lower annual generation output per installed MW compared to thermal power plants. This fact is even more pronounced in forthcoming scenarios.

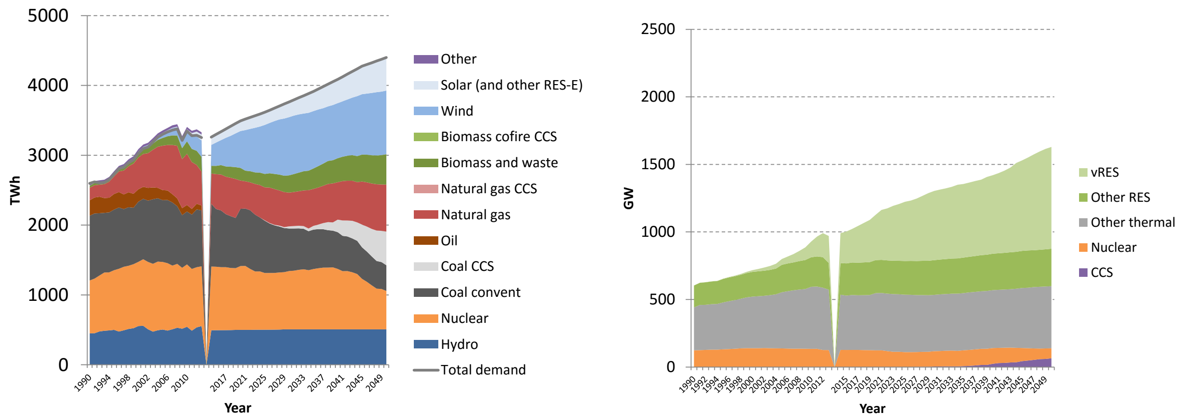


Figure 39. Electricity generation (left) and electricity-generation capacity (right) in Europe in the Reference scenario (vRES=variable renewable electricity generation).

Regional Policy scenario

The Regional Policy scenario includes highly ambitious targets for CO_2-emissions reductions (30% reduction in emissions from electricity generation by year 2020, 50% reduction by year 2030, and 99% reduction by year 2050, as compared with the levels in year 1990), with goals of increasing the share of RES-E and increasing energy efficiency. Thus, this is distinctively a “go for all goals” scenario. Furthermore, the RES-E and efficiency policy targets are met nationally (hence the term ”regional”). The Regional Policy scenario is characterised by detailed policy steering, with emphasis on efficiency measures, and it has a national policy view rather than a common European policy-instrument design. Model results are reported in Figure 40. In the case of CCS, which becomes profitable post-2040 albeit to a limited extent, this consists both of coal-fired schemes and of biomass-coal co-fired units with a typical co-fire share of 10% biomass. Given the comparatively higher carbon intensity of biomass compared to coal fuels and since CCS is assumed to capture around 90% of the CO_2 emissions while emitting the rest, such co-fired CCS schemes provide the possibility for reaching zero (or even slightly negative) CO_2 emissions. The CO_2-reduction target of virtually 100% explains why coal-only CCS drops to zero towards the end of the period, yet, in reality such units can be upgraded to include biomass co-firing.

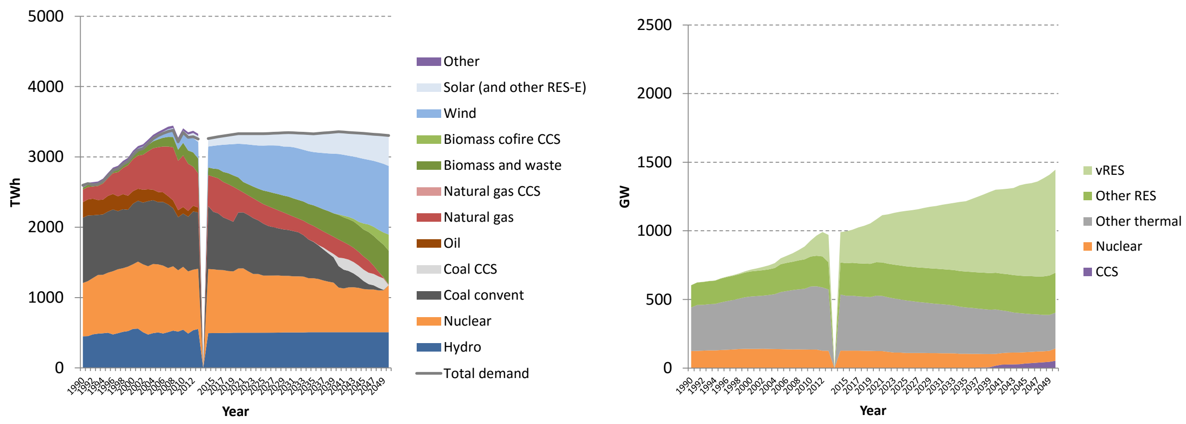


Figure 40. Electricity generation (left) and electricity-generation capacity (right) in Europe in the Regional Policy scenario (vRES=variable renewable electricity generation).

Climate Market scenario

The Climate Market scenario focuses exclusively on climate mitigation post-2020. Thus, this is distinctively a ”one-goal scenario” or, alternatively, a “go for climate” scenario. CO_2 emissions from electricity generation are to be reduced by 93% by year 2050 (50% by year 2030), as compared to the levels in year 1990. Since the electricity demand is larger in this scenario than in the Regional Policy scenario, we assume a slightly different balance in CO_2-reduction burden-sharing between electricity generation and the other sectors. In both scenarios, however, we assume a reduction target of at least 80% for the entire energy system as defined by the EU Roadmap towards 2050. In the Climate Market scenario, no other policy targets are specified post 2020. Thus, this scenario allows “unbiased” competition between all the included supply technologies. Electricity demand is growing faster than in the other scenarios due to electrification and due to the absence of specific end-use efficiency targets, as in the Regional Policy scenario but also to some extent in the Reference and Green Policy scenarios. Given that electricity is produced with little or no emissions, increased electrification, in for example, transportation, heating, and industrial processes, may in itself be considered as a climate- mitigation measure if it replaces the direct use of fossil fuels in these sectors. The model results are reported in Figure 41. All technologies contribute to filling the gap between demand and the existing generation, where the latter declines over time. Significant growth occurs in renewable electricity generation, even though a dedicated RES-E policy is absent post-2020. The relatively high marginal costs of electricity in this scenario cover also the costs for new nuclear power plants and CCS. In this scenario, there are large new investments in conventional fossil power, mainly in natural gas, until 2040–2045 when the CO_2-reduction requirements make this type of electricity generation unfeasible. Growing electricity demand and significant expansion of vRES also in this scenario explains the very large capacity build-up up to 2050 (Figure 41, right)

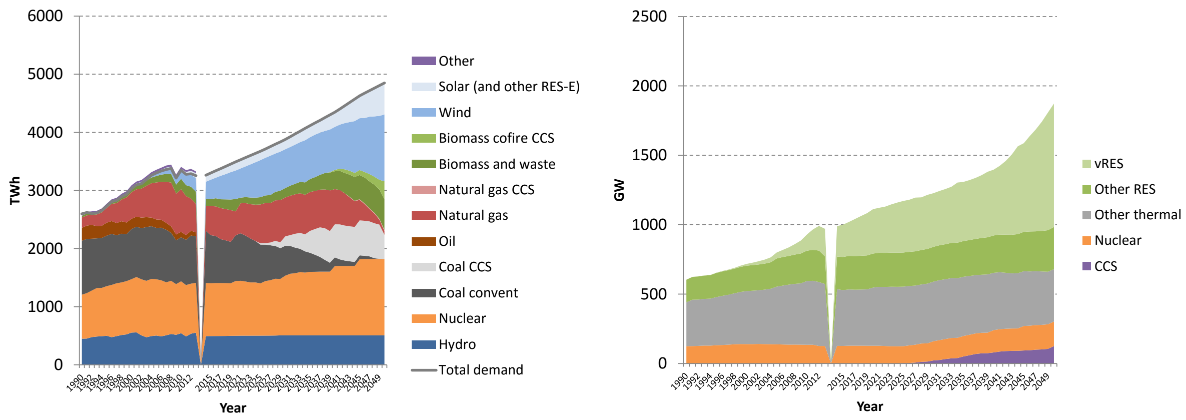


Figure 41. Electricity generation (left) and electricity-generation capacity (right) in Europe in the Climate Market scenario (vRES=variable renewable electricity generation)

Green Policy scenario

As mentioned above, The Green policy scenario is characterised by a very high share of renewable electricity generation in year 2050. In the model set-up, this is achieved through a very ambitious and common European tradable green certificate scheme that over time increases the penetration of RES-E of gross demand to 95% by 2050, which implicitly rule out both the option of new investments in nuclear power and the commercialisation of CCS. The expansion of RES-E is further facilitated by stringent CO_2-reduction targets for the electricity supply (30% reduction in emissions from electricity generation by year 2020, 55% reduction by year 2030, and 93% reduction by year 2050, relative to the levels of emissions in year 1990). Furthermore, the expected operational lifetimes of existing nuclear power plants are shorter in this scenario at 45 years, as compared to the other scenarios (60 years). The model results for this scenario are shown in Figure 42. By year 2050, wind power becomes the largest supplier of electricity, generating almost 2 000 TWh in year 2050, i.e. around half of the gross demand. This accords with the vision for year 2050 of the EWEA both in terms of absolute and relative size (EWEA, Position paper).[11] We conclude that significant investments in conventional fossil-fuelled (natural gas) generation capacity occur during the entire period until year 2045, at which time-point the very stringent CO_2-reduction commitments make the use of natural gas without CCS unprofitable. The lion share of such investments are in gas turbines for regulating back-up purposes, i.e. entailing very low annual capacity utilization. Thus, as shown in Figure 42 (right) available thermal capacity is significant even though utilization is low. Furthermore, the total capacity build-up is extreme in this scenario due to the very high share of wind and solar power.

[11] EWEA Position paper "2050: Facilitating 50% wind energy", available at http://www.ewea.org/fileadmin/files/library/publications/position-papers/EWEA_2050_50_wind_energy.pdf 2015-03-31

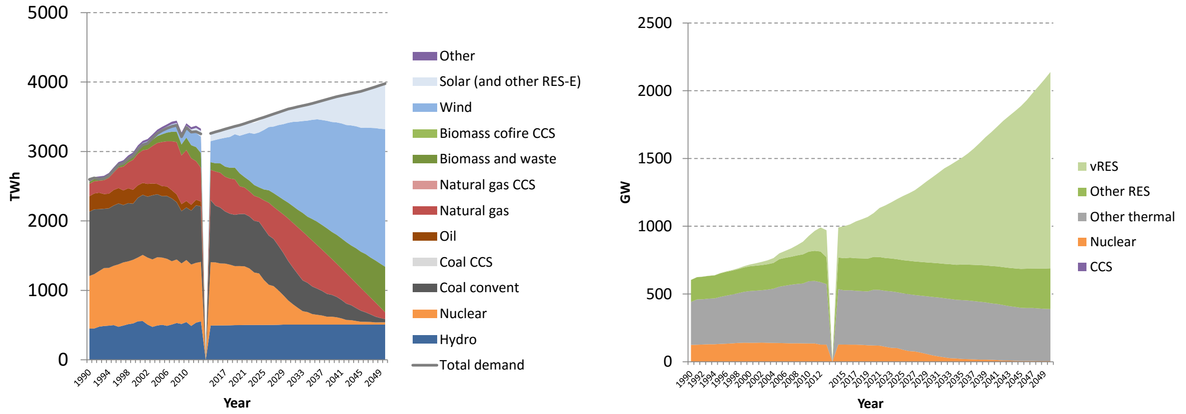


Figure 42. Electricity generation (left) and electricity-generation capacity (right) in Europe in the Green Policy scenario (vRES=variable renewable electricity generation).

Cross-scenario comparisons

In this section, we highlight some important results for all scenarios in a collective manner in order to enable cross-scenario comparisons.

Electricity supply

The model output on electricity supply (generation and capacity) was shown, in detail, for each scenario in the preceding section. In Figure 43, the electricity generation and capacity is shown for all four scenarios and for two model years, 2030 and 2050. We may find that all scenarios but Regional Policy imply a significant increase in demand and, thus, production. However, all scenarios including Regional Policy imply a massive increase in generation capacity. This includes both vRES capacity and thermal capacity for back-up purposes. Both these technology groups imply relatively low annual utilization. We may also, once again, conclude on the significant capacity build-up across all scenarios. This becomes especially apparent in our Green Policy scenario where total installed capacity by 2050 is more than twice the existing capacity in 2015. Also in our Climate Market scenario, the total installed capacity is very large due to both massive investments in vRES but also due to increasing electricity demand. However, while vRES capacity amounts to more than 65% in the Green Policy scenario, the corresponding share in the Climate Market scenario is less than 50%. Thus, while almost equal in available capacity, the challenges related to balancing and regulating vRES generation are of less magnitude in the Climate Market scenario, at least in terms of traditional options managing the balance on the supply side with the aid of dispatchable power plants.

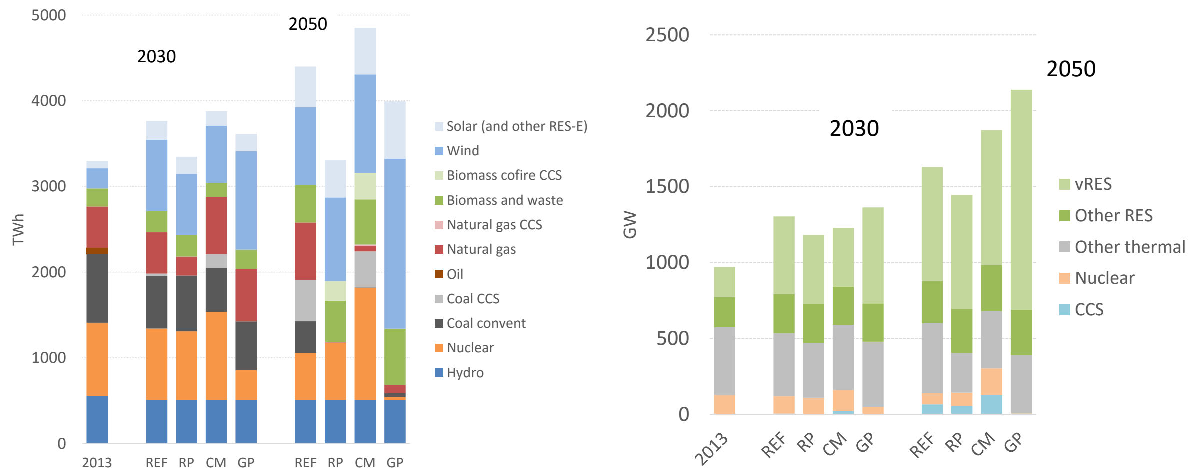


Figure 43. Electricity generation (left) and electricity-generation capacity (right) in Europe in 2030 and 2050, respectively, for all scenarios (vRES=variable renewable electricity generation). RP=Regional Policy, CM=Climate Market and GP=Green Policy.

Interconnector capacity

Another model output is the investments in interconnector capacities between countries. We assume that significant interconnector capacities across Europe are optional from 2020 and onwards. However, actual investment decisions are endogenous in the model and, thus, a model output dependent on whether the wholesale electricity price difference between two countries is large enough to motivate investments in interconnector capacity. Figure 44 indicates that interconnector capacities increase quite significantly in all scenarios, by at least a doubling by 2030 compared to the existing capacity of approximately 50 GW. Especially in the Green Policy and Climate Market scenarios, new investments in interconnector capacity are very large. In the Green Policy scenario, this is explained by the large regional diversity of CO_2-lean investments meaning that certain regions in Europe are dominated by wind power, while other regions may invest more heavily in biomass or solar power. Such differences give incentives for trade. Furthermore, timely differences in wind availability between two wind-power dominated regions may further increase incentives for cross-border trade.[12] In the Climate Market scenario, the regional diversity is further extended since this scenario also contains regions with significant penetration of CCS and nuclear power. In the Regional Policy scenario with its lower electricity demand and in the Reference scenario with its lower penetration of CO_2-lean supply, investments in new interconnector capacity are more limited than in the other two scenarios.

The massive expansion of interconnector capacity reported in Figure 44 should be viewed as desirable and cost-efficient given the different conditions defined in our scenarios in the model setup. However, lead times are not included in the model. In reality, investments in interconnector capacities are heavily influenced by national regulation and grid conditions in two different countries and, generally, associated with long lead times, typically 10-15 years (Svenska Kraftnät, personal communication). Given these limitations, the model results presented in Figure 44 are, of course, very challenging. Furthermore, the size of the investments in interconnector capacity also serves as

[12] Such conclusions may be drawn from model analyses with significantly higher intra-annual time resolution, e.g. single hours, than what is possible with the ELIN model used in the present analysis. Hourly resolution is achievable in the EPOD model that is linked to the ELIN model and also used frequently by the research team at Chalmers.

an indicator of corresponding investments in the national transmission grid. The ELIN model may also be run in regional mode (not done in the present study), i.e. each European country is subdivided into one or several regions defined by key bottlenecks in the national grid. Experiences from such model runs indicate that investments also in the national transmission grid are of substantial size given that the ambitious energy and climate policy goals of the EU towards 2050 are to be met in a cost-efficient way.

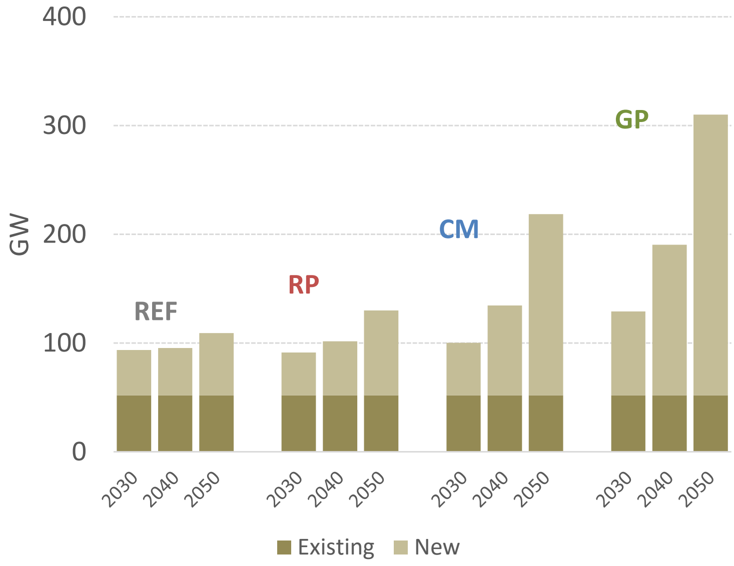


Figure 44. Total interconnector capacity in Europe in all four scenarios and for 2030, 2040 and 2050. Existing interconnector capacity amounts to approximately 50 GW.

Capacity investments

In this section, we take a closer look at the key issue in this study: the pace and size of the capacity investments towards 2050. We also estimate the number of thermal power plant installations that is needed in order to reach the scenario goals and compare that to the existing number of such installations.

In Figure 45, we present the average annual capacity investments or, more specifically, commissioning of power installations (in five-year periods) since 1970, and compare them to the corresponding annual investments given by the ELIN model runs for all four scenarios. We may find that, historically, we had peaks in annual capacity investments during the 1980s when the absolute lion share of the European nuclear power plant fleet was commissioned and during the last decade when the massive investments in wind and solar power across Europe was initiated. Based on our scenarios, we may conclude that the capacity-investments pace in thermal power plants is in parity with the historical level up to 2035 for virtually all four scenarios. Post 2040, the annual capacity investments in thermal power supersedes the historical levels due to the heavy investments in gas turbines needed for back-up capabilities, but also due to investments in CCS, biomass and nuclear depending on scenario. Above all, however, investments in variable renewable electricity generation, foremost wind power and solar power, dominate the annual capacity investments. This also means that a very large share of the investments made in future electricity generation are made by other investors than traditionally has been the case. Instead of large or semi-large utilities, investments may largely be handled by smaller actors such as e.g. private persons and small business associations.

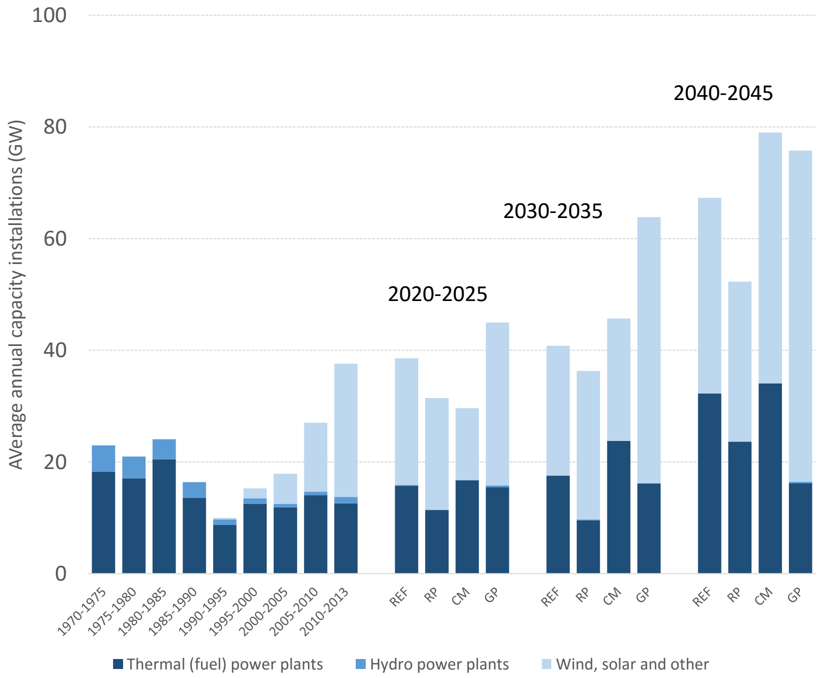


Figure 45. Average annual capacity investments (commissions) in five-year periods for different means of electricity generation and for all main scenarios (Source for 1970-2013: Chalmers Power Plant Database). RP=Regional Policy, CM=Climate Market and GP=Green Policy.

In Figure 46, we present the corresponding information as in the previous Figure 45 but shown as upfront investments in electricity generation in Billion EUR. According to the figure, average annual investments lie typically at about 40 Billion EU until 2025 and increase to around 40-80 Billion EUR, depending on scenario, per year between 2030 and 2035. This accords with the estimates made by IEA in their latest World Energy Outlook (2014) for the EU (roughly 60 Billion USD as an annual average calculated from the cumulative estimate of around 1600 Billion USD between 2014 and 2040 for the IEA "New Policies" scenario).[13] Annual upfront investments increase over time as existing capacity is phased out and as a consequence of increased stringency of climate policies. The Climate Market scenario distinguishes itself somewhat from the other scenarios during the last five-year period due to significant investments in capital-intensive technologies such as nuclear power and CCS. These technologies require higher upfront investments for each GW than e.g. solar and wind power that dominate the Green Policy scenario. This becomes especially pronounced post 2030 due to assumptions on continued reduction in investment costs for solar and wind power.

[13] IEA 2014, "World Energy Outlook 2014", ISBN: 978-92-64-20805-6.

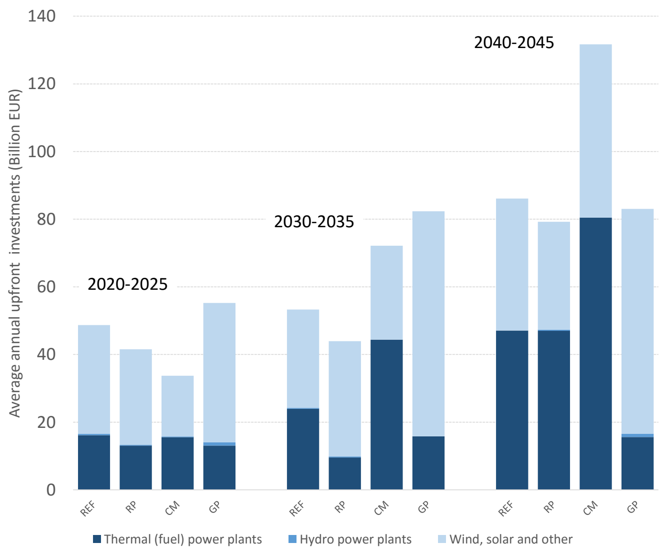


Figure 46. Average annual upfront investments (in Billion EUR) in five-year periods for different means of electricity generation and for all main scenarios. RP=Regional Policy, CM=Climate Market and GP=Green Policy.

Electricity prices and prices of CO_2

The model approach used in the analysis generates, for each model run and scenario, electricity prices and prices of CO_2.[14] The CO_2 price is a proxy for the EU ETS price even though the emission-reduction cap involves only the electricity system in the analysis. The cap on emissions from electricity generation in each scenario is estimated with respect to the overall EU goal of at least 80 percent reduction by 2050 and an estimate of the burden-sharing between the electricity sector and the rest of the energy system in Europe (taken from, among others, the EU Roadmap scenario analyses with the PRIMES model).

The CO_2-price development in the four main scenarios is presented in Figure 47. Since the cap is common to all European countries, the countries also share the same CO_2 price. The figure clearly shows low prices of CO_2-emission allowances until year 2020. This is largely explained by the RES-E targets, which are active in all the scenarios until year 2020. This further underlines the current situation in the real-life EU ETS market, where low prices are foreseen until year 2020. The expansion of renewables, mainly with respect to electricity generation, offsets a significant share of the fossil-fuelled electricity generation, entailing a decrease in demand for emissions allowances. Post-2025, the calculated price of CO_2-emission allowances starts to increase in all the scenarios, with the exception of the Regional Policy scenario. Continuation of the RES-E policy and ambitious efficiency policies in the Regional Policy scenario lead to very low prices of CO_2 even though the reduction targets are ambitious. It is not until after year 2035 that the price of CO_2 increases also in the Regional Policy scenario.

The price development in Figure 47 is the result of a delicate balance between the three policy targets included in this scenario. In contrast to the Regional Policy scenario, the Climate Market

[14] More specifically, the model calculates the marginal cost of generating electricity and the marginal cost of reducing CO_2 for a given CO_2-reduction cost. In reality, the formation of a market price includes more components such as risks and consumer behaviour and flexibility which is not fully reflected in the model. Nevertheless, we still use the term “price” since the calculated price is a fair proxy of an actual market price.

scenario, with comparable trajectories for reductions in CO emissions, exhibits relatively high prices of CO_2 already after year 2020. This is the result of the “one target” policy. All the effort to reduce emissions is put into the carbon market. The price of CO_2 in the Reference scenario level out at around 40 €/tCO_2 after year 2030. This is a consequence of the significantly less ambitious year 2050 target, i.e., around 65% reduction in emissions from electricity production by year 2050, than the corresponding targets in the other three scenarios.

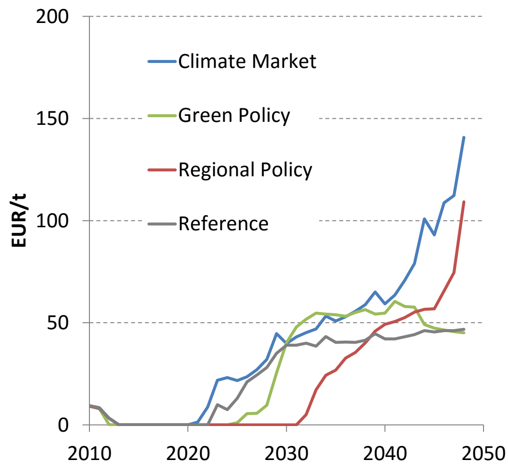


Figure 47. Calculated CO_2-price development for all four main scenarios for the period 2015-2050

The calculated wholesale electricity price is a model result that yields important information as to the impacts of the different scenario assumptions. In Figure 48 (left panel), we show the calculated wholesale electricity price for all four scenarios. Hence, this is the income derived from an electricity generator. The price is calculated as a weighted average (weighted against electricity demand) of the individual calculated wholesale electricity prices of all the countries included in the model. Possible differences between national prices of electricity are a result of interconnector bottlenecks. In the figure, the “mean” European MC for electricity is stable at around 35 €/MWh for all scenarios until year 2020. Thus, the current “low price regime” persists. Despite slowly increasing fossil-fuel prices and increasing pressure to reduce CO_2 emissions, the wholesale electricity price is relatively low. The reason for this is, as in the case of the CO_2 price, the RES-E target, following the NREAPs of the Member States, which constantly pushes new renewable capacity into the supply system in all four scenarios until year 2020. This prevents the wholesale price of electricity from increasing. After year 2020, the wholesale electricity prices diverge across the scenarios. In the Regional Policy and Green Policy scenarios, for which we assume continued and relatively ambitious RES-E support beyond year 2020, the wholesale electricity prices are significantly lower than in the two other scenarios until 2025-2030. Also the Reference scenario includes RES-E support post 2020, yet at a somewhat lower level. In particular in the Regional Policy scenario, in which we assume the most ambitious direct RES-E support and far-reaching end-use efficiency policies, the calculated wholesale electricity prices are persistently low until year 2030. Beyond year 2040, the prices start to increase also in the Regional Policy scenario as a result of the very stringent CO_2-emission reduction target. In the Green Policy scenario, the early phase-out of nuclear power across Europe (45 years lifetime instead of 60 years in the other scenarios) imply that the corresponding supply deficit of emission-free electricity generation needs to be replaced by new capacity. This exerts an upward pressure on the electricity wholesale prices. The price increase culminates around year 2035 when the ambitious RES-E targets have managed to fully complete the supply gap. Thereafter, continued RES-E support to reach the target of 95% renewable electricity generates excess capacity why prices start to fall. A sensitivity analysis assuming 60 years of lifetime for nuclear power instead (as in the three other main scenarios) indicates that wholesale electricity prices would remain at a constant low level throughout the entire period up to 2050 in the Green Policy scenario. In the Climate Market scenario, RES-E targets are removed after year 2020. As mentioned, the focus is solely on reducing CO_2 emissions, which rapidly increases the prices of CO_2 (as previously shown) and thereby also increases the wholesale electricity price.

To reflect the cost of the RES-E target (by year 2020 for all scenarios and for the Regional Policy, Green Policy and Reference scenarios beyond year 2020), we have in Figure 48 (right panel) calculated a proxy for consumer electricity prices. This consumer-price proxy excludes taxes and electricity-distribution costs but includes the cost of RES-E support. The latter is obtained as a shadow price on the RES-E target in the model results. Thus, we have added the weighted European RES-E "price" (actually, the marginal cost of the RES-E target) to the calculated wholesale electricity price, and calculated a weighted mean European "consumer price" of electricity. The European RES-E "price" is calculated as a weighted average across all countries' individual RES-E "prices". Thus, this might be viewed as a situation in which all countries have domestic tradable green-certificate (TGC) schemes and all the electricity consumers have to pay for that scheme. If only a certain percentage of the consumers are involved, e.g., excluding electricity-intensive industries, the resulting "consumer price" of electricity will be higher for that group of consumers, since the weight of the RES-E price will be higher. In the Green Policy scenario, the RES-E price is common to all countries post 2020 due to the assumption of one single RES-E-support market.

We may see in Figure 48 (right panel) that the "consumer price" is roughly the same across all the scenarios until year 2020 (assuming that all electricity consumers are included in the TGC scheme). As mentioned earlier, this also applies to the wholesale electricity price. After year 2020, the calculated consumer price diverges from the calculated wholesale price only in all scenarios but Climate Market since this is the only scenario that lacks a specific RES-E target, and thus a support scheme, after 2020. Especially in the Green Policy and Regional Policy scenarios, the consumer price is significantly higher than the corresponding wholesale electricity price. This is due to the relatively high RES-E prices found in these two scenarios.

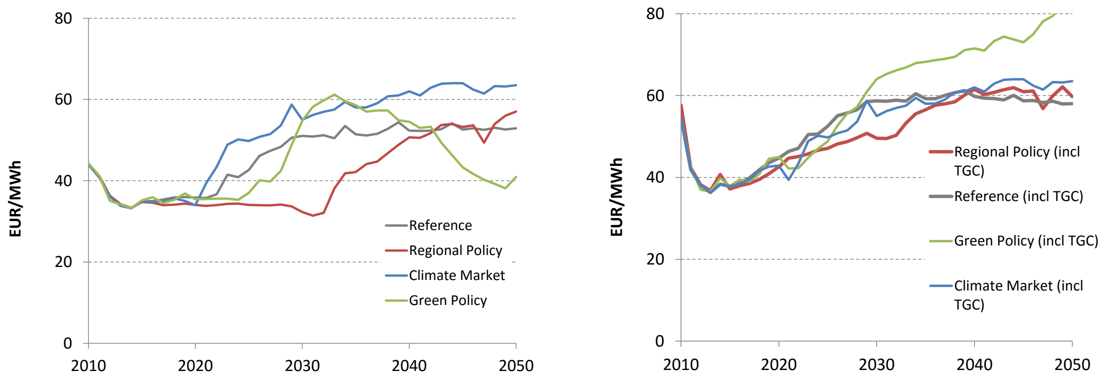


Figure 48

The Regional Policy scenario and the Climate Market scenario both share the same predefined goal of reducing CO_2-emissions by more than 90% by 2050. The means to reach that target and the balance between the included policy instruments do, however, different significantly. In Climate Market, only the reduction target matter while in regional Policy also RES-E and efficiency targets matter.

The reason for the pronounced increase in wholesale price in the Green Policy scenario, despite its massive policy-induced investments in renewable electricity, is largely found in the assumptions on remaining life times in nuclear power stations across the EU. If we replace the assumption on 45 years as the upper limit of operational lifetime of the nuclear power reactors with an assumption on 60 years instead (as for the other three scenarios) we find that the average wholesale electricity price as defined here is considerably lower than in any other case (Figure 49). At the same time, calculated certificate prices in order to meet the targets on renewable electricity are accordingly higher and, consequently, impact retail electricity prices. Since the Green Policy scenario assumes very stringent CO_2-reduction targets the availability of a significant supply of emission-free production, i.e. nuclear power in this case, is, of course, of importance to the electricity price. If the life length is relatively shorter, nuclear power must be replaced by other means of production including fossil-fuel based generation with increasing costs as emission-reduction targets become tougher. It is not until the end of the time period when renewables account for almost all of the electricity supply that we may observe a decoupling of the wholesale electricity price from the price of CO_2.

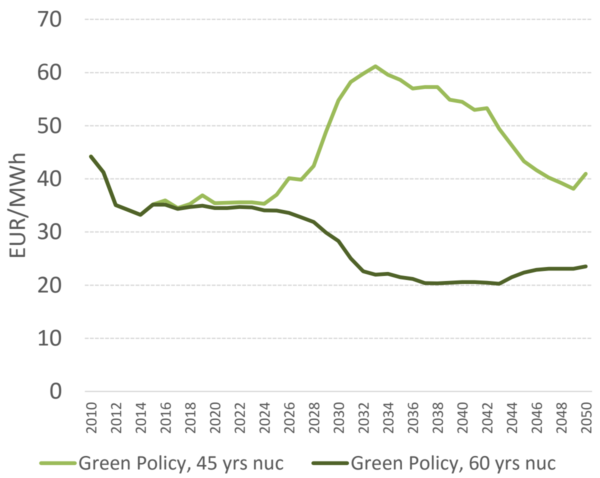


Figure 49 The impact of choosing a reduced lifetime for existing nuclear power, 45 years, in the Green Policy scenario compared to the default assumption of 60 years.

We may conclude that RES-E are likely to have profound effects on the electricity markets. Wholesale electricity prices will come under pressure and retail prices will increase if RES-E support is transferred to consumer bills. Even though not specifically addressed here, the same applies to the efficiency target. Costs for reducing electricity consumption are borne by other support mechanisms and, thereby, reducing electricity prices at the wholesale level. Depending on the design of efficiency policy measures, these costs may also be transferred to the electricity bills as e.g. white certificates.

In Figure 50 we summarize the impacts on wholesale and retail electricity prices of the three energy and climate policy goals: reducing GHG emissions, increasing RES-E and reducing energy use.

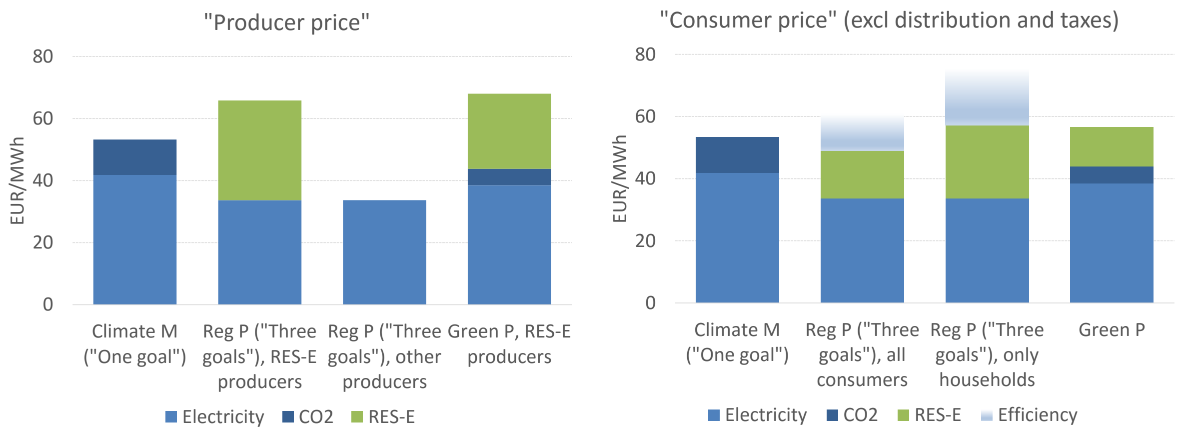


Figure 50. Impact on the wholesale (left) and retail (right) electricity price (calculated as an European average) of the three European energy and climate policy instruments (typical level for the period 2025- 2030; excluding taxes and grid fees).

Nordic and Swedish electricity system outlook

The historical development

The electricity system in Sweden and the Nordic countries is, unlike the electricity systems in other EU countries, characterised by an electricity generation with low emissions of greenhouse gases and a large share of renewable power generation. The electricity demand used to steadily increase in all Nordic countries, but it has stagnated in recent years. Together with an increased support to the expansion of renewable power generation, this has contributed to a power surplus, resulting in a significant net export of electricity to our neighbouring countries the last 3-4 years. At the same time, there has been a substantial drop in the price of electricity since year 2010, in the wholesale price on the Nordpool market as well as in the retail price.

The different future scenarios presented in this chapter should be seen with this historical development and the current (mainly positive) situation in mind. The Swedish and Nordic electricity system is not facing the same big climate and energy challenges as the European electricity system as a whole is. Our electricity system might rather contribute to the solutions in other countries and in other sectors.

But, let us briefly look at the historical development again, before presenting the scenario results for the future development.

The electricity generation in Sweden and the Nordic countries since year 1990

The development of the Swedish and the Nordic power generation since year 1990 is presented in Figure 51. Characteristic is the large share of electricity generated in power plants with low, or no, emissions of fossil carbon dioxide (Nuclear power plants and power generation using renewable energy). In Sweden this share has steadily been on average 95% during the period 1990-2012, and 85% in the Nordic countries. In EU 28, the same figure is 50% today (2012).

The renewable electricity generation has increased gradually, not the least due to the electricity certificate system in Sweden and corresponding policy instruments in the other Nordic countries. In the Nordic countries as a whole, the renewable share of the electricity generation was about 60% in the early 90s, and today it is about 65%. In Sweden, the share of renewable energy has increased from 50% to a bit more than 55% during the same period. In EU 28 the renewables share is approximately 25% today.

Another characteristic element of the Swedish and the Nordic electricity generation is the (large) inter-annual fluctuations in the hydropower generation resulting from water influx variations, which is clearly illustrated in Figure 51.

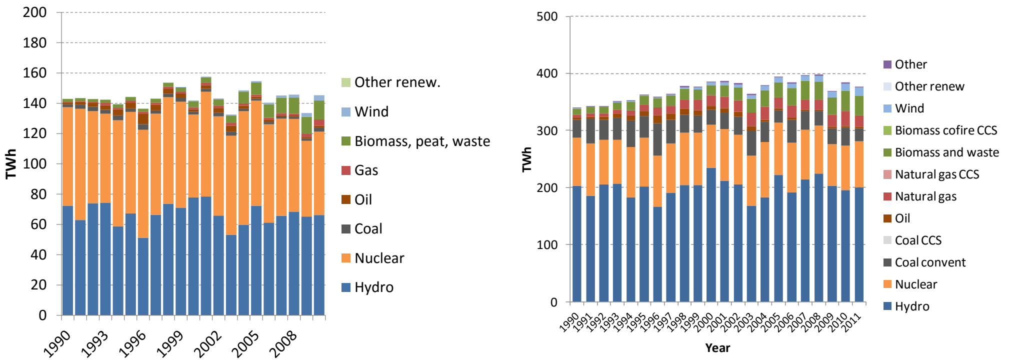


Figure 51. The Swedish and the Nordic power generation since 1990. (Source: Eurostat).

Electricity trade between Sweden, the Nordic countries and the rest of Northern Europe

Electricity transmission between the Nordic countries and the neighbouring countries was relatively limited during the 90s, with little variation between different years (See Figure 52). But, since the turn of the century, it has been characterised by large inter-annual variations as a consequence of fluctuations in the influx to hydropower plants and by an increased, but stable, net import from Russia to Finland of about 10 TWh/year. For most of the years since 1990, the Nordic countries have been a region with a net import of electricity. Typically, it has been at the level of 5-10 TWh / year during the 21th century, but with large inter-annual variations.

2012 was a reverse in the trend. As a result of good access to hydropower and nuclear power, a continued expansion of renewable electricity generation, and an unusually small Russian export to Finland (app. 4 TWh), the Nordic power surplus, and thereby also the export, was record-breaking. A total of almost 15 TWh was exported from the Nordic countries to Germany, Poland, Russia, Netherlands, and Estonia. (Swedenergy, "*Elåret 2012*"). The Swedish net export was even larger than that, close to 20 TWh (the major part was electricity exchange with the other Nordic countries). This large export during year 2012 might indicate a change where the Nordic countries, and not the least Sweden, in the future will play a role as net exporters of electricity (See below for the scenario results for the future development). The Swedish net export was relatively large already in year 2011, approximately 7 TWh. But, the same year, the net trade for the Nordic countries as a whole showed an opposite development, with a net import of about 5 TWh.

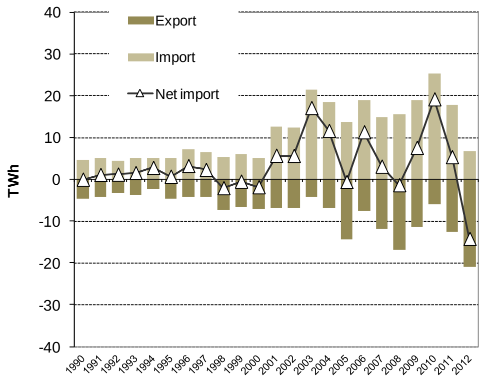


Figure 52. Swedish and Nordic electricity export (negative bars) and electricity import (positive bars) during the period 1990 – 2012.

Electricity demand in Sweden and the Nordic countries since 1990

Since the beginning of the 21th century, the electricity demand has stagnated in Sweden and Denmark, whereas the same trend cannot be seen in Finland and Norway until year 2005. In the immediate vicinity of the Nordic countries, Germany and Poland are large consumers of electricity. While the demand has declined in Germany, it has continued to grow in Poland as a result of the economic expansion there.

The future development of the Swedish and Nordic electricity systems

The Nordic electricity system is well prepared to meet the future uncertainties and challenges

The different energy system scenarios we have analysed should be viewed with this historical development and the current - largely positive - situation, in mind. The Swedish and Nordic electricity system is not facing the same climate and energy challenges as the electricity system in the rest of Europe. On the contrary, our electricity system might contribute to solutions in other countries through an increased export of electricity, and in other sectors through an increased electricity use.

In NEPP we have analysed four main scenarios, all based on different assumptions regarding the political energy and climate goals, and other external factors that are influencing the development of the electricity and energy systems. We have investigated the energy related, as well as the capacity related challenges this scenarios points out. Our result shows that the Swedish as well as the Nordic electricity systems are very well prepared to meet all the electric energy related demands to relatively moderate costs – regardless of scenario – and to deliver a product that is close to CO_2 free and has a very high share of renewable production.

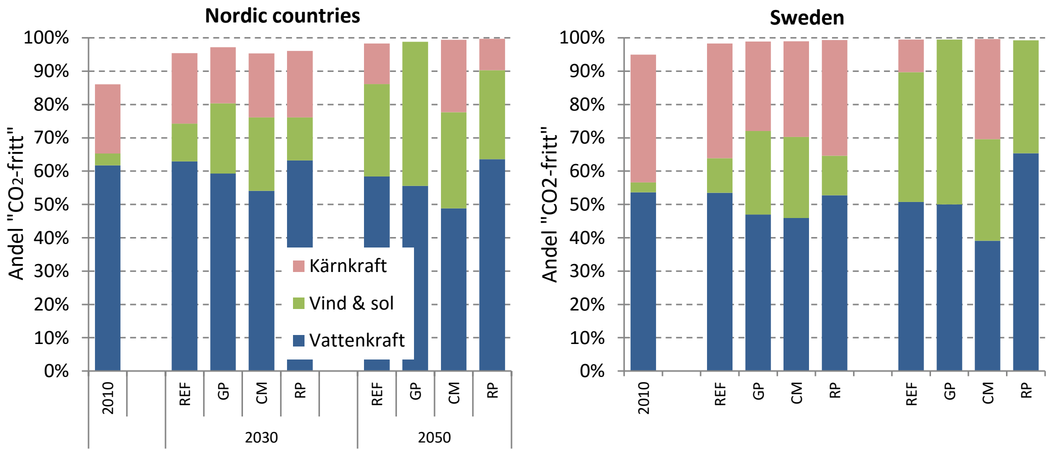


Figure 53. The composition of the Nordic and the Swedish electric energy generation in year 2010, 2030 and 2050, with different development paths according to our four energy system scenarios. (Please note that the figure above shows shares, not absolute numbers. For instance, the amount of hydro power ("Vattenkraft") is constant through all scenarios, but since the total amount of electricity generation varies, the shares of the different kinds of power are affected. In several of the figures on the forthcoming pages, rather the absolute figures are illustrated. ("Kärnkraft" = Nuclear power; "Vind & sol" = Wind and solar power.)

The four main scenarios are:

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

The sensitivity analysis has, amongst other things, included:

- **Share of renewables**: Different speed of development and ambition level for renewables.
- **CO2 price**: Different development paths for the CO2 price.
- **Nuclear power**: The sensitivity for different assumed investment costs, lifetimes, and taxes.
- **Economic development and energy demand**: Different development trends for the GDP.

The most significant energy system uncertainties/challenges for the electricity system are associated with capacity

With a development of the energy system, and of the external factors, without any dramatic changes, the Swedish and Nordic electricity system will, with a high probability, be able to handle also the future capacity situation with a reasonable effort. But, the uncertainties are greater for the capacity related challenges than for the energy related ditto. In our energy system analyses from where the results presented in this publication are taken, we have particularly identified the following "capacity related uncertainties and challenges":

- The Swedish nuclear power and the consequences of an early decommissioning.
  - Also an early decommissioning of other thermal power plants.
- An EU, Nordic or Swedish policy that results in a very large share of new (renewable) power. (E.g. powerful political directives with policy instruments that also promotes a large Nordic export of electricity to the Continent.)
  - I.e. driving forces/uncertainties both within and outside Sweden/the Nordic countries
- A GDP growth larger than what is prognosticated (The prognoses show a GDP growth of 1.5% in the EU as a whole, and about 2% in the Nordic countries.)

Besides this, market failures (e.g. an insufficient development of the regulatory framework), poor acceptance of the investments in the infrastructure necessary for the electricity capacity, water rights that require reduced capacity in the hydro power plants, climate related challenges, weak incentives for smart grid solutions, etc., might also create capacity related uncertainties, but these factors are not addressed in this book, but in other theme book from NEPP.

The Swedish and Nordic electricity and heating systems are close to CO_2-free, it's better to focus on other sectors

As already mentioned, the Nordic electricity generation is associated with very low CO_2 emissions, and they will decline further, even with the existing policy instruments. It is also likely that we will see a growing Nordic power surplus. This leads to the conclusion that future efforts to reduce the CO_2 emissions in Sweden and the Nordic countries should focus on other sectors. The sectors with the largest emissions are industry and transport, and the sector that really differs from the others regarding fossil fuels is the transport sector. Electrification can then be a powerful tool for changing this.

Moreover, the Nordic countries can make an even larger effort to produce CO_2 free electricity, and contribute to lower European CO_2 emissions through export of electricity. Making such a development profitable, will require EU-common policy instruments that give Sweden and the Nordic countries strong enough incentives (see a specific section below).

The challenges and the uncertainties the electric system is facing in the rest of Europe are much tougher, and many countries have demanding transformation targets to deliver to the coming years

The electric systems on the Continent and in UK are in the midst of a transformation to a more renewable power generation, with targets for year 2020 as well as for year 2030 (and in the long run also for year 2050). At the same time, the emissions of carbon dioxide must be reduced, even more than what is related to the increased share of renewables, especially by year 2030 and year 2050. The long term ambition in EU is a very carbon dioxide lean electricity generation by year 2050.

A comparison between the Continent and the Nordic countries regarding which challenges and uncertainties the EU's energy and climate targets mean for the electric system, reveals big differences (see the "scorecard" below).

Challenges/Uncertainties 2030	The Continent and the UK		Sweden and the other Nordic countries	
Renewable energy (increased share)	Very large challenge		No/moderate challenge	
Reduction of carbon dioxide	Very large challenge		No/moderate challenge	
Capacity management *	large challenge		Moderate challenge	
Transmission and distribution grids	large challenge		Moderate challenge	
Profitability for thermal power	large challenge		large challenge	
Development of the electricity market **	large challenge		Moderate challenge	
Nuclear power (country specific)	large challenge	Moderate challenge	large challenge	Moderate challenge
CCS (technology and acceptance)	Very large challenge		No/moderate challenge	
Development of the electricity demand ***	Moderate challenge		Moderate challenge	
Transmission lines Nordic countries-Continent/UK	large challenge		large challenge	

*On the supply side as well as on the demand side. ** Reported in more detail in another NEPP theme book.
***Uncertainty regarding the magnitude as well as the load profile of the electricity demand.

Our analyses show that the challenges are large even in a longer perspective (2050), regardless of which technology for power production that will be predominating. Even though all four scenarios we have analysed show an increased share of renewable power generation, the share in the Climate Market and Reference scenarios is smaller than that in the Green Policy and Regional Policy. In the scenarios with a smaller share of renewables there are instead reinvestments in nuclear power and – on the Continent – establishment of CCS, as complements to the renewable electricity generation.

Both these development paths will mean a large infrastructural challenge for Europe:

- A continued expansion of wind and solar power will require a massive expansion of the transmission grids and efforts to secure capacity in thermal plants.
- A large-scale establishment of CCS will require an infrastructure for CO_2 management.

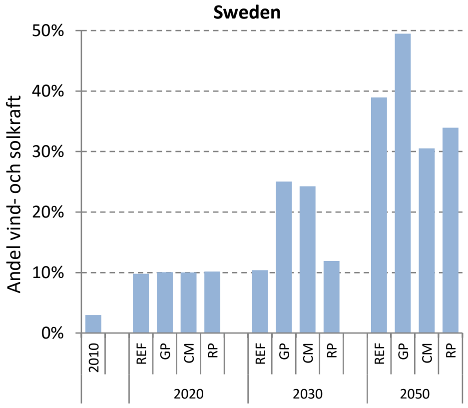
The technical electricity and energy system is inert

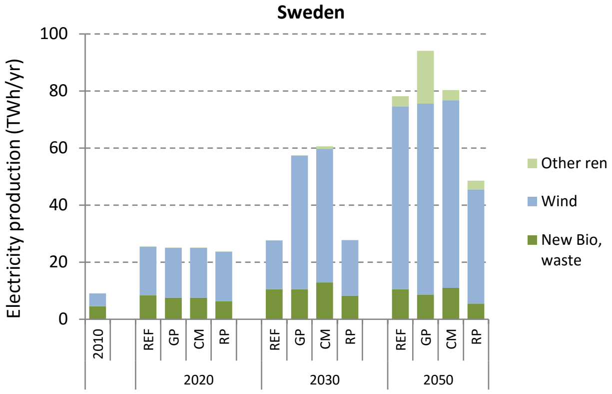
The existing energy infrastructure, in the form of production, distribution, and user technologies is only slowly replaced. Most of the technologies in the Swedish, Nordic and European electricity systems have a technical lifetime of 30-50 years or more. Therefore, in the perspective of 15 years, i.e. up to year 2030, we cannot expect any major changes in the technical system, even if the incentives for change are strengthened. In the perspective of 30-40 years on the other hand, up to year 2050, there might be more radical changes. It is important to realise that the existing electricity production system is the starting point for the future development, and it will have an influence on the development of the electricity system in many years to come. Current means of production and fossil fuels will dominate European Electricity production another 15-20 years, even with a massive expansion of the renewable production. In our NEPP scenarios the renewable production will increase gradually. But a large share of the electricity production in Europe will still be fossil fuel based by year 2030, and a not insignificant share will still be so by year 2050. A prerequisite for reaching a very low level of CO_2 emissions also on the Continent is that CCS becomes commercially viable and generally accepted, which is uncertain today.

The renewable electricity is increasing, but how much renewables we will have in Sweden and the Nordic countries the next 10-15 years is determined exclusively by our own politics

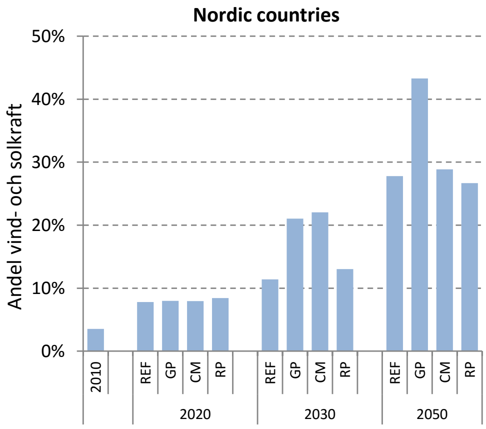
In a longer perspective - after 2030 - all our scenarios show a demand for relatively large quantities of wind power (and also solar power), but in a shorter perspective the need is smaller. Neither EU requirements, nor electricity shortage motivate more renewables in the short term, only the national political requirements do.

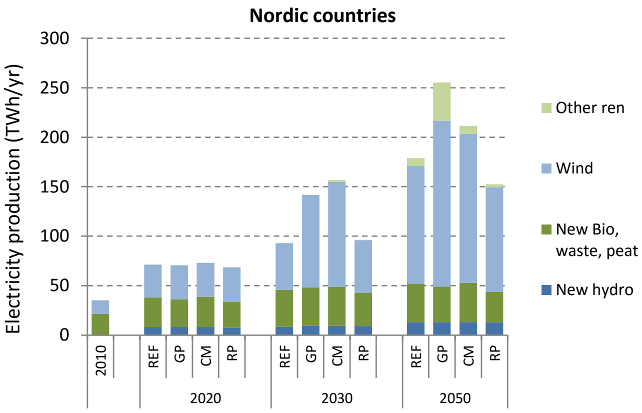
This is obvious in the figures on the next side. In all scenarios, the expansion of renewable power stops at levels of a little bit more than 20 TWh (relative the levels in year 2003, i.e. the base year of the electricity certificate system). If the political incentives are not strengthened between year 2020 and year 2030, and if the electricity demand is not increased by a rapid economic recovery, the increase in renewable power will not be particularly large. This is illustrated by the Reference and Regional Policy scenarios in the figure. If, on the other hand, the political incentives (i.e. the CO_2 price and/or the electricity certificate ratio) are strengthened between year 2020 and year 2030 (and this continues also beyond 2030), and the electricity demand is taking speed at the same time as a phasing-out of the nuclear power is initiated, then there will be a continued large demand for renewable power in Sweden as well as in the Nordic countries also during the period 2020-2030. The scenarios Climate Market and Green policy in the figures above show such a development. In a really long perspective, up to year 2050, we will reach levels for wind and solar power of 30-50 %of the electricity generation in all scenarios in Sweden as well as in the Nordic countries. In three of our four scenarios as much as 70-80 TWh might come from wind and solar power in the Swedish electricity generation.





Share of and amount of new renewable electricity generation (relative 2003) in Sweden in our four main scenarios. ("Andel vind- och solkraft" = Share of wind and solar power.)





Share of and amount of new renewable electricity generation (relative year 2003) in the Nordic countries in our four main scenarios. ("Andel vind- och solkraft" = Share of wind and solar power.)

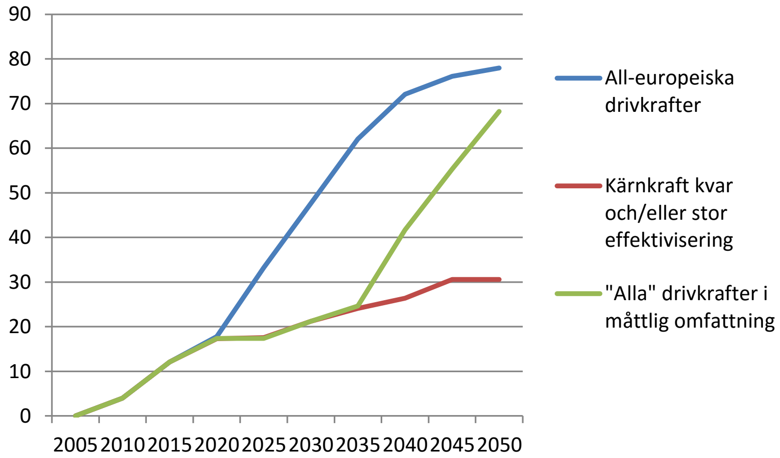
Synthesis of our scenario results

Sweden and the Nordic countries have the right conditions for a far-reaching transformation of the energy supply to a large share of renewable energy, not only in the electricity and heat production, but also in industry and transportation; conditions that are far better than those for the countries on the Continent.

Several Nordic countries also have political goals and visions about a future with 100% renewable energy in all sectors of the society.

But, the Nordic countries do not have to produce more renewable energy above the quantities defined by the current policies, in the short term - before year 2020 - to fulfil our EU commitments. And, we are already well on our way to reach the year 2030 goals. At the same time, we have an electricity system characterised by a power surplus, low wholesale prices and a large export. Further investment in renewable power will augment this surplus situation, as long as the current declining demand is not shifted to a massive increase, or nuclear power plants are phased out.

Also, there is nothing in our results that indicates that an expansion of renewable energy is necessary in the short term (5-15 years), to prepare for a large scale expansion in the longer perspective, e.g. in preparation for a coming decommissioning of the nuclear power. This is clearly illustrated by the results from the Reference scenario, which show a development in which (all) the driving forces for the transformation are utilised to a limited degree. In the two scenarios with powerful and pan-European policy instruments (CM and GP) which will promote a continued large transformation, a more continuous expansion of renewable power will be seen throughout the whole studied period.



A synthesis of the combined results from our scenarios and sensitivity analyses, where we have high-lighted the driving forces that are common for three different expansion strategies. The figure shows the amount of new renewable electricity generation (relative 2003) in Sweden, in TWh. ("All-europeiska drivkrafter" = All-European driving forces; "Kärnkraft kvar och/eller stor effektivisering" = No decommissioning of nuclear power and/or a large amount of energy efficiency; "Alla drivkrafter i måttlig omfattning" = All driving forces utilised to a limited degree.)

What is required for a really massive expansion of renewables up to year 2030?

With our commitments related to the EU's climate and energy political goals taken into account, there is (as discussed earlier) no rationale for a further expansion of the production of renewable power in Sweden or the Nordic countries, beyond what is stipulated by the policy instruments already in action. However, additional national ambitions might form the basis for a substantially larger expansion. There are also a number of energy related uncertainties that – if a continued investment in renewable is assumed to reduce them – might increase the need for renewable power significantly before year 2030. Three examples are:

- Nuclear power and the rate of its phasing-out/expansion. There is an uncertainty about how long our oldest units can be kept in operation. And it is not clear how fast potential reinvestments in new nuclear power capacity might be implemented, and if they will pay back.
- The development of the electricity demand. A fast and powerful recovery of the economy might result in a significant increase of the electricity demand.
- The opportunities for, and the need of, a large electricity export.

Based on the scenarios and sensitivity analyses we have performed in NEPP, and solely based on those, our analyses show a very low probability that any of these three uncertainties will mean increased incentives for more renewable electricity generation (beyond the current support) before year 2025. But after that, the impact is likely to become significantly larger (given a continued tightening-up of the EU's policies). Political decisions in the individual Nordic countries might however, as mentioned, result in continued strong incentives for investments in renewable power generation. And if there is a (pronounced political) ambition to relatively rapidly phase out the nuclear power – and to reduce the profitability for reinvestments in new nuclear power reactors – a continued massive development of renewable electricity production might be a logical strategy regardless of scenario. Firstly, the resulting very low wholesale price of electricity will mean a low profitability for all existing production (which is not receiving support for renewables). Secondly, this will prevent that reinvestments in nuclear power will reduce the space for a later large expansion of renewables.

Factors of importance when introducing new variable power

The share of new variable power: A large share of wind and solar power will mean tough requirements on new grids, capacity management and smart grids (even if all new power production has a similar effect). How big the expansion of variable/intermittent electricity generation in Sweden, the Nordic countries and in Europe will become, is therefore of great significance to the need for upgrades of the grids and for measures to secure capacity availability in the production. In the scenarios with the most massive expansion of renewables (particularly in GP) the share of renewable power capacity will reach more than 40% already in 25 years, in the Nordic countries as well as in Europe as a whole. In the scenarios with a more moderate development of renewables, the share of intermittent power capacity will be lower, and will at most reach 30% by year 2050 (20% by year 2030).

Location: Where the variable electricity generation will be situated is also of significance. This is particularly true for the wind power, where the development in Northern Europe mainly has been concentrated to Denmark and Northern Germany. In the scenarios with a large expansion of wind power in Northern Europe (e.g. GP), a continued North-western localisation is dominating, since this is where the best winds are found. Such a concentration of wind power leads to increased requirements for upgrades and intelligence in the system.

Composition: How the composition of the variable/intermittent electricity production in Northern Europe turns out is also of great importance. The variable renewable alternatives for electricity production dominating the expansion is wind and solar power. These are variable in different ways, with solar power following the diurnal rhythm, and wind power being even more genuinely variable. The distribution of the production over the year is also different. The development of wind and solar power is also in different stages, with wind power being further advanced in development and cost level and therefore expanding faster than solar power. This is obvious in our model calculations. There are also differences between the technologies regarding magnitude of scale. Typically, wind power is of a larger scale, is run by professional actors, and the electricity is fed to the system on a relatively high voltage level. Solar cell installations are significantly smaller, are run by homeowners, and the electricity is fed into the low-voltage network.

Policy instruments: Several of the dominating policy instruments, e.g. green certificates and electricity tax, do not take the level of the electricity generation at different points in time into account. As the amount of variable electricity generation grows, the incentive to review the design of the policy instruments to avoid sub-optimisations also grows. As an example, it could be motivated to question the support to electricity production if there are low or even negative prices of electricity. Also, the need for a tax on electricity consumption can be questioned with such electricity prices. Instead, the policy instruments could be shaped to be even more powerful when the electricity balance is stressed.

The prices of electricity will remain low in the short term (5-10 years), regardless of which of the main scenarios we look at

The price of electricity in Sweden has dropped considerably since year 2010, and is now at a relatively low level. This goes for the wholesale price on the NordPool as well as the retail price (which in Sweden amongst other things includes the electricity certificate fee). In the short perspective (5-10 years) none of our main scenarios show any real increase in prices, neither in the Nordic countries, nor in the EU as a whole. Both the Swedish and the Nordic electricity balance is good, the energy and climate targets for year 2020 are within reach (thereby not demanding any costly investments in new capacity), and demand is not expected to grow very much the coming 5-10 years (GDP prognoses for Sweden and the EU predict, as discussed above, only a moderate rate of growth). Also for the price of green certificates, only a modest rise is expected up to year 2020.

Sensitivity analyses performed in the NEPP project indicate that the price of electricity might become even lower if, for instance, the electricity demand turns out to be lower than expected. Other factors that might result in even lower prices of electricity is if the transmission grids to the Continent are not further developed (with inexpensive electricity ”trapped-in” in the Nordic region), or if policy instruments supporting renewable electricity are further strengthened (e.g. a higher level of ambition in the green certificate system).

The latter example however, will only lower the wholesale price of electricity, while the retail price (here defined as wholesale price + green certificate price) for those that are quota obliged might increase slightly when the price of electricity certificates rises.

Of course, there are also a number of factors that might push the price of electricity upwards. This can, for example, be a fast phase-out of a number of nuclear power reactors, or a faster than expected rise in the electricity demand.

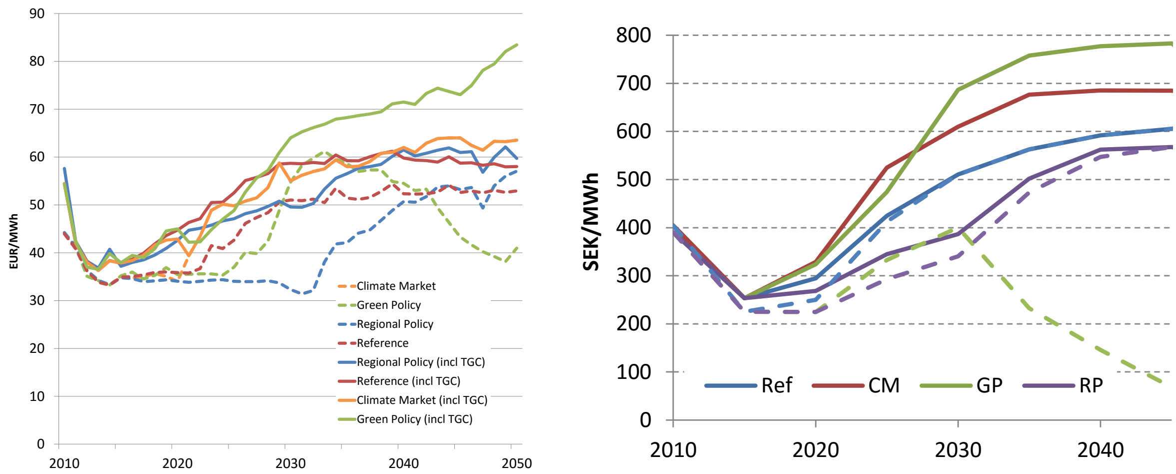
The end-user price of electricity will rise in the long perspective

Strict CO_2 regulations aiming at climate neutrality and at a large share of renewables, raise the prices of CO_2 and electricity. The price for end-users will rise in the long term in all of the scenarios. In the Reference scenario, and in the Regional Policy scenario, the price of electricity will in a longer perspective reach levels of around 500-600 SEK/MWh (app. 60 EUR/MWh). In the Climate Market scenario it will reach over 600 SEK/MWh (over 60 EUR/MWh). In the Green Policy scenario, which includes a comprehensive support system for renewable generation of electricity (e.g. electricity certificates), our analyses point towards prices of electricity of up to 700-800 SEK/MWh by year 2050 (75-85 EUR/MWh), if all customers are obliged to buy certificates. The price of the certificates will then constitute at least half of the price of electricity, in the Nordic countries up to 80-90%. If, like today, only a part of the customers are concerned, the price of electricity might even reach levels of up to 1200 SEK/MWh by year 2050, in a scenario with a very large share of renewable electricity production. Other customers, e.g. energy intensive industries, will then at the same time be charged relatively low prices for electricity (as today or even lower).

In the scenarios not including any extended support system for renewables, i.e. the Climate Market and Reference scenarios, the price of CO_2 is the main policy instrument. In our analyses, as well as the analyses performed by the EU in their roadmap work, the price of CO_2 reaches levels of up to 150-200 EUR/tonne, if CO_2 emissions are reduced 70-90% up to year 2050. In spite of this very high CO_2 price, the price of electricity will go through only moderate rises in these scenarios and reach around 600-700 SEK/MWh by year 2050. Thus, an increased electricity production with low CO_2

emissions will result in a more pronounced decoupling between the price of electricity and the price of CO_2.

The discussion above and the figures presented describe the development of the average yearly price of electricity. Other analyses, in NEPP and in other studies, indicate a development where the variation in the price of electricity is amplified when more of variable electricity generation is added. However, in the Nordic countries this tendency is markedly suppressed by the balancing role hydropower is playing. Calculations show that it takes large amounts of wind power before the Swedish price of electricity demonstrates significantly longer periods of extremely low or extremely high levels. There are also trends in the opposite direction, e.g. the consequences of a larger share of solar power. The massive German development of solar power has so far resulted in a levelling-out of the price of electricity over the day, with less difference between high load (day) and low load (night).



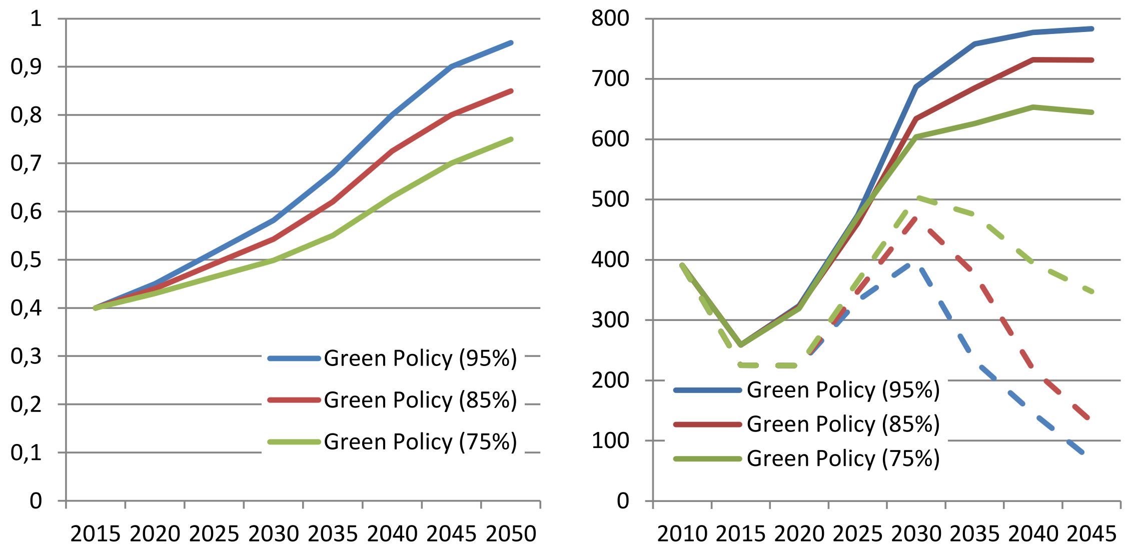
Nordic (left figure) and European (right figure) prices of electricity in the four NEPP scenarios. (Dotted lines = wholesale price, Solid lines = retail price. i.e. wholesale price + green certificate price).

The demand for a very large share of renewable power generation pushes down the wholesale price to low levels, which means that investments in wind and solar power need state support even with a continued strong technology development.

In scenarios with the main focus on increasing the share of renewable electricity generation, the cost of the support will constitute an increasingly larger share of the final retail price. But, the support systems' capability to stimulate large quantities of electricity generation with very low variable costs, e.g. wind and solar power, gives as a result a wholesale price that is rather moving in the opposite direction, and will drop as the share of renewables increases.

The figures below show the results from NEPP's sensitivity analysis of three different levels of the share of renewables in the Northern European power generation. The total retail price, i.e. the wholesale price + support (e.g. the fee in a common Northern European electricity certificate system) is developing rather similarly in the three scenarios (the solid lines in the right figure). The difference between the scenarios is rather how the two price components are developing. In the scenario with the smaller share of renewables (up to 75% by year 2050), the certificate fee - which is the difference between the retail price and the wholesale price in the figure - will never grow larger than the wholesale price. However, in the scenario with the larger share of renewables (up to 95%), the certificate fee will reach the same level as the wholesale price already a few years after year 2030, and by year 2050 it will make up no less than 85-90% of the retail price.

The sensitivity analysis demonstrates quite clearly that the balance between the wholesale price and the certificate fee (cost for support to renewables) is sensitive to how large the renewable share that is demanded from the power generation is.

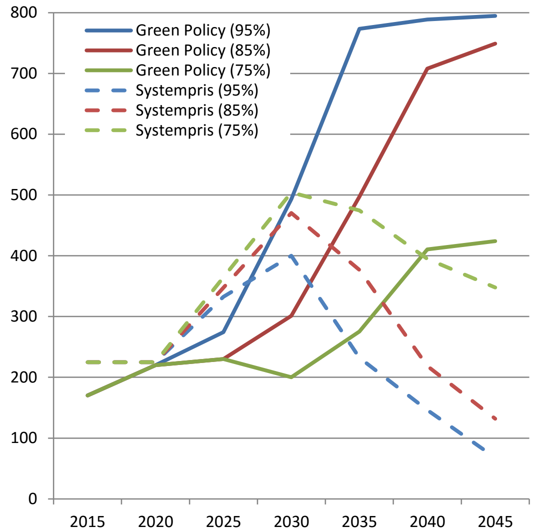


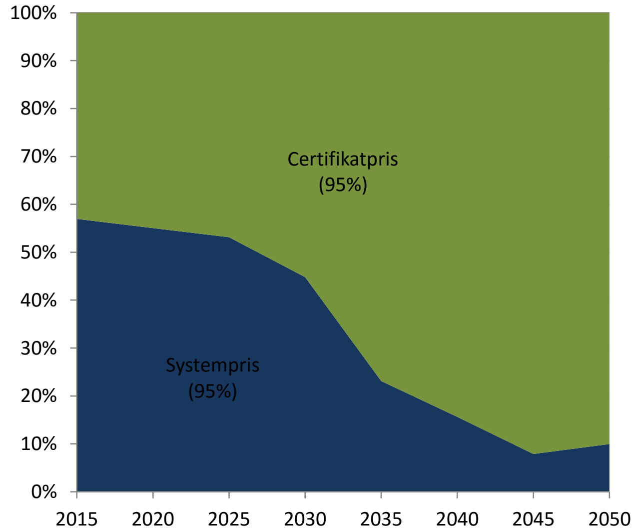
Sensitivity analysis for the Green Policy scenario, in which we have tested the sensitivity to different alternative levels of the renewable share in the Northern European electricity generation (left figure) and the resulting outcome (right figure) for the wholesale prices (dotted lines), and for the retail prices (solid lines).

In the presentation above the view is the customer perspective. Then, the retail price is consisting of the wholesale price of electricity, and the electricity certificate fee that is a result of the volume of renewables that is "forced through". If looked at from a producer perspective on the other hand, the value of the electricity production from renewable energy is the sum of the wholesale price of electricity and the price of electricity certificates. The price of certificates is defined by the market, and is a result of the amount of renewables demanded and the costs of the technologies at hand. Only the renewable electricity generation is associated with electricity certificate costs. Other electricity generation will only have the wholesale price.

Costs for certificates awarded the producer will be paid by the customers in the form of the electricity certificate fee discussed above. In the sensitivity analysis described above, it is charged as a general fee for all electricity use. Since the income from electricity certificates is based on a larger amount of electricity (the total electricity use), the electricity certificate prices (which are awarded only to renewable electricity generation) will be higher than the electricity certificate fee. The figures below present the outcome from a producer perspective.

The left figure below makes it obvious that the wholesale price of electricity is far from enough to give incentives for the development of such large amounts of renewable electricity generation. Powerful support is needed, e.g. a North European electricity certificate system. The figures also illustrate the dilemma that the more renewables that is demanded, the further away we will end up from a situation where the price of electricity by itself gives strong incentives enough for the renewable generation of electricity. Obvious is also the very low long term revenues for non-renewable electricity generation.





Sensitivity analysis of the Green Policy scenario (With Northern Europe as the system delimitation) with the producers revenues (left panel, dotted line = wholesale price, solid line = certificate price), and the relation between the wholesale price and the electricity certificate price in the Green Policy 95% scenario (right panel). The revenue from generation of renewable electricity will after year 2035 to 80-90% consist of the electricity certificate price. The revenue from generation of non-renewable electricity, i.e. the wholesale price solely, will steadily decline over time in this scenario. (We assume an "energy-only market", without any capacity market component).

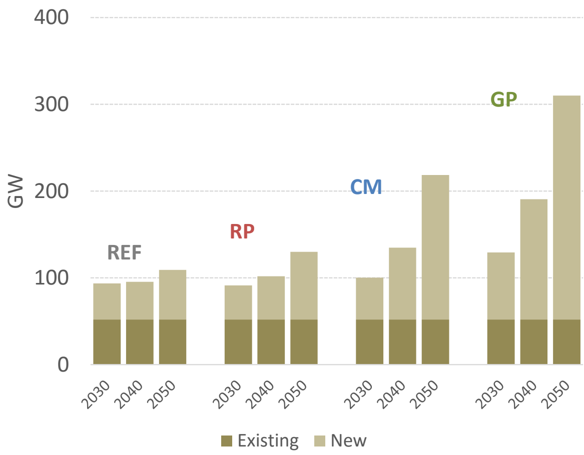
It will take a strong pan-European driving force and an adequately large differentiation in electricity prices for a large electricity export and a massive development of the transmission capacity to take place

Sweden, and the Nordic countries have, as already discussed, good conditions for a far-reaching transformation of the energy supply towards a large share of renewable energy. Far better than the countries on the Continent. In the electricity sector this brings opportunities for an export growth, and to support the countries on the Continent in their development.

Our four main scenarios, and our sensitivity analyses, point out two quite different development paths for how large the export of electric energy from the Nordic countries to the Continent might become in the future:

- **The export remains approximately at the same level as it is today**, and the demand for a further development of the transmission grid beyond what is already planned will be relatively small (from energy reasons). This development can be seen in the Reference (REF), and the Regional Policy (RP) scenarios. In the first case (REF) there are reinvestments in nuclear power approximately up to the same level as we have today, but the electricity demand is growing and the development of renewables is slow. Thus, there will be little room for export. In the three-goal scenario RP, the wholesale price is not high enough to justify reinvestments in nuclear power, which therefore will decline significantly in the long run. At the same time, the electricity demand will decrease due to efficiency improvements, and support to renewables will increase the electricity generation based on renewable energy. Altogether, this will result in a relatively balanced Nordic electricity supply, and a small electricity export. Even if the export of electricity is moderate, both these scenarios show an increase of the transmission capacity in a 20 years view.

- **The export increases significantly**, and new transmission lines, in addition to what is planned today, will be built. By year 2030, we may have a doubled transmission capacity, and by year 2050 it may be as large as three times what it is today. We can see this development in both of the two "one-goal" scenarios Climate Market (CM) and (especially) Green Policy (GP). In CM, with gradually higher prices of CO_2, the wholesale prices will be pushed upwards. This will in turn lead to profitability for reinvestments in nuclear power and, at the same time, to a continued development of renewables. The export will be large, but restricted by the large increase in electricity demand in the Nordic countries, resulting from the continued electrification of several end-user sectors. The largest export is rather to be found in GP, where a continuously larger support to renewables will result in very large amounts of renewable power generation. The low wholesale prices of electricity means that there will be no investments in nuclear power. A moderate Nordic electricity demand leaves a large space for export of electricity.



Total transmission capacity from the Nordic countries to the rest of Europe in four different NEPP scenarios (REF = Reference scenario, RP = Regional Policy, CM = Climate Market, GP = Green Policy)

CM and GP have in common a strong pan-European driving force (price of CO_2 or support to renewables), and a differentiation in the price of electricity large enough to make a large export of electricity profitable.

The expansion of renewable power calls for an extensive and rapid development of the transmission grid even within the European countries since it is, in many parts, already overloaded. As for CCS, a massive expansion of the grid is associated with large uncertainties, and it is therefore also a crucial factor in the transformation.

Our main scenarios and sensitivity analyses show three different development paths, which all of them (each one by itself, or all together) may, in the longer perspective, lead to a large export of electricity from Sweden and the Nordic countries to the Continent – significantly larger than today:

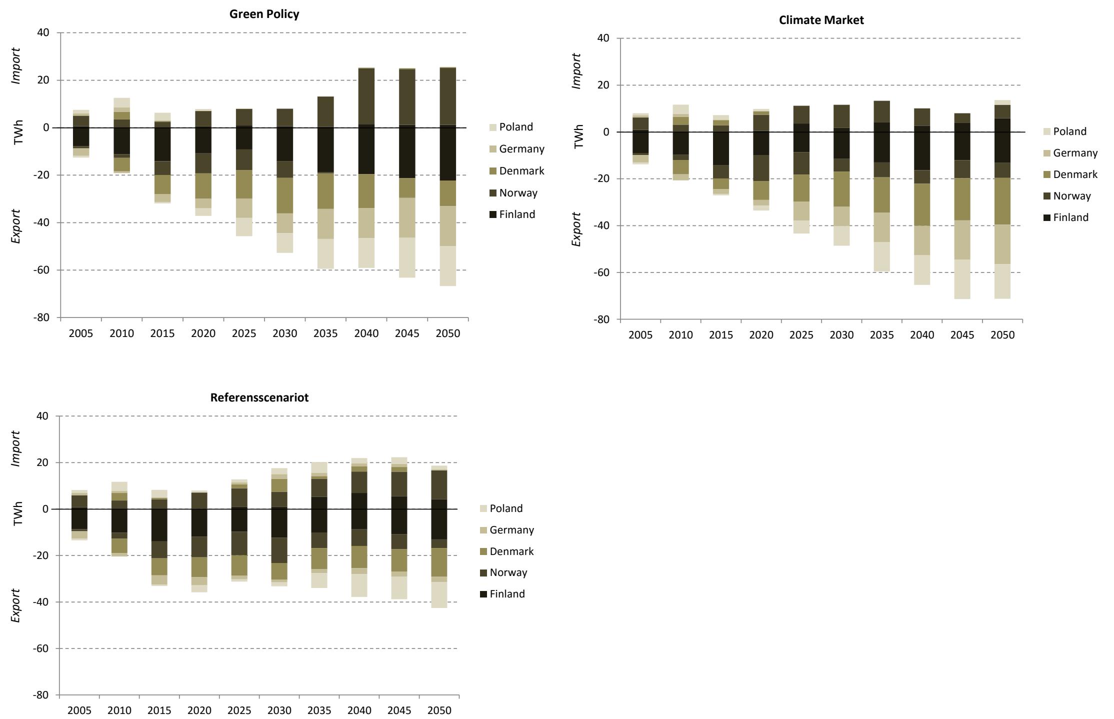
- A high price of CO_2 in the EU.
- A European over-arching support system for renewables, which is high enough, and which encourages choosing the most cost-efficient measures in the EU, regardless of in which country they are implemented.
- Reinvestments in Swedish nuclear power.

However, the development in the short term, and also in the long run for the scenarios with moderate levels of the CO_2 price or little support for renewables, will not give the right conditions for a really large export. The same can be said about the scenarios with three goals. With the EU policy of today running up to year 2030, it is unlikely that we will see a large increase of the Nordic electricity export, unless one or several things of the following happen:

- The GDP development takes speed and pushes the continental prices of electricity upwards.
- There is a stronger focus on “security of supply”.
- There is a common system for support to renewables implemented in the EU.

Sweden will continue to be a dominating exporter as long as we have nuclear power

Sweden will be the dominating exporter of electricity in Northern Europe in all of our NEPP scenarios, with a net export of 15-20 TWh by year 2030, and we will continue to have a large power surplus. With continued investments in renewable electricity generation in Sweden, while we also maintain the nuclear power, we will soon have a surplus of electricity. If we however, in a longer perspective, phase out the nuclear power, we will not have this surplus (unless the support to renewables becomes extremely large).



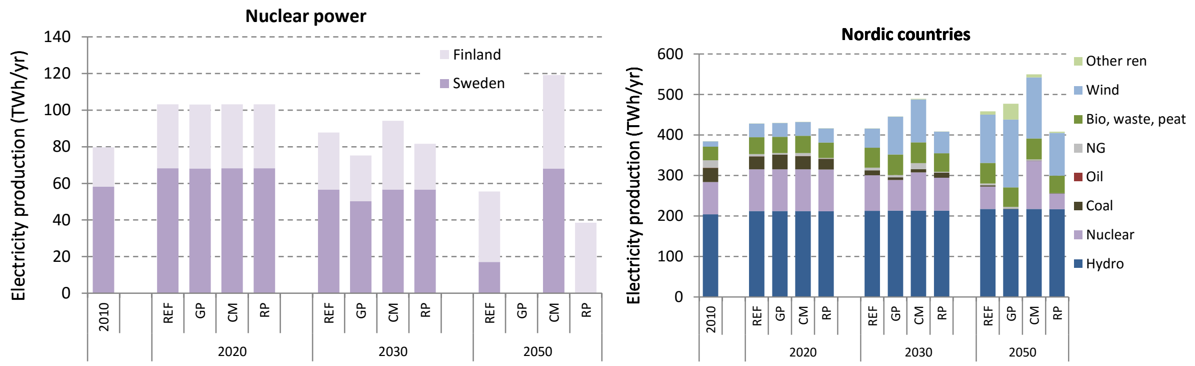
Export (negative figures) and import (positive figures) of electricity from and to Sweden during the period 2010-2050. The results from three of the NEPP scenarios.

The Swedish nuclear power is maintained through reinvestments in the scenario with a high price of CO2, and phased-out in the scenarios with a large support to renewables and improved efficiency

The assumptions about the rate of the phasing-out of the *existent* Swedish nuclear power plants, and the conditions for reinvestments in new plants in Sweden and Finland, are scenario-differentiating in our four main scenarios, and in our results. This is visualised in the figures below. In the left panel we have extracted the nuclear power production from the four scenarios and presented it subdivided into Swedish and Finnish nuclear power.

The reference scenario, and particularly the Climate Market scenario (CM), are the scenarios exploiting nuclear power the most. For the Swedish and Finnish nuclear power, CM means a more or less maintained nuclear power production during the whole studied period up to year 2050, and an increased production compared with today in Finland.

In the Region Policy and the Green Policy scenarios however, all Swedish nuclear power is phased out by year 2050, as well as the older Finnish nuclear power plants. Only the newer of the Finnish plants will be kept. The reason behind the decommissioning is that the wholesale price of electricity will become too low to make (re)investments in nuclear power profitable. The phasing-out will be fastest in the Green Policy scenario, where also a shorter lifespan is assumed for the nuclear power (45 years rather than 60 years as in the other scenarios).



Nuclear power production in the Nordic countries in the four scenarios (left panel), and the total electricity generation in the Nordic countries, (right panel, from which the nuclear power figures in the left panel are extracted).

For new nuclear power to be competitive, wholesale prices of at least 550-600 SEK/MWh are required, according to NEPP's model analyses. These levels will not be reached until after year 2025 and mainly in the Climate Market scenario (but also in the reference scenario after year 2035). In the Green Policy scenario on the other hand, we have assumed that no reinvestments will be allowed in any of the EU Member States for political reasons.

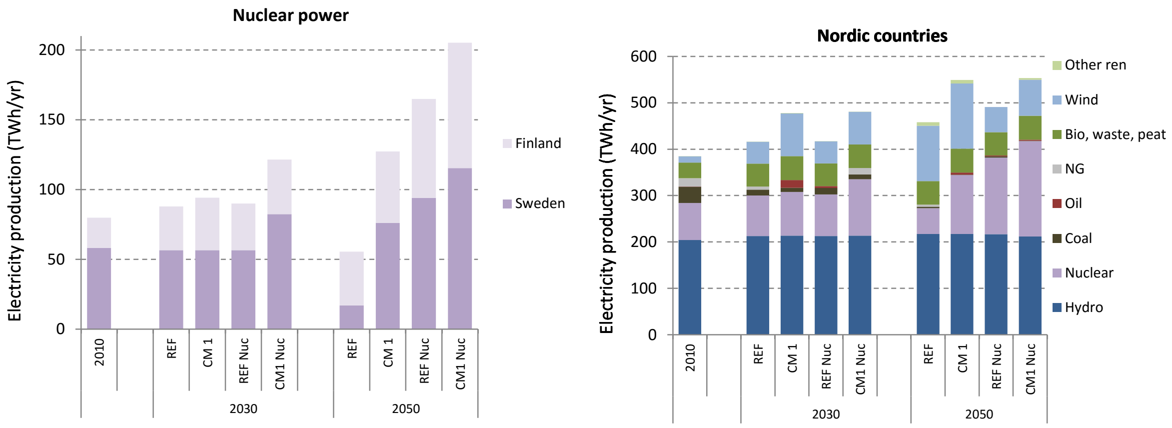
In our sensitivity analysis of the development of the Swedish nuclear power, we have tested the sensitivity of the results to variations in three different assumptions in the calculations:

- The scenario results' sensitivity to the level of the Swedish thermal effect tax for nuclear power has been tested, and it has been taken away in its entirety.
- The scenario results' sensitivity to the level of the nuclear power's investment costs has been tested, in the interval +/- 20 % (50 000 SEK/kW as the baseline assumption).
- In the Reference and Climate Market scenarios we have, in the alternative calculations, extended the reinvestment options so that it allows the capacity of today to be exceeded.

The results are illustrated in the figures below. From these results three obvious conclusions can be drawn:

a) The results in the Reference and Climate Market scenarios are very sensitive to these variations in the assumptions regarding the nuclear power. With a reduction of the assumed level of reinvestment costs for nuclear power by 10-20 %, or with an elimination of the Swedish capacity tax, the profitability of reinvestments in Swedish nuclear power will increase dramatically. Contrary to the almost complete phase-out of Swedish nuclear power in the reference scenario, we would see an expanded nuclear power production compared with today.

- The assumed level of the investment cost for nuclear power has a significant impact on the result. Only a relatively moderate reduction of the cost is needed to make the reinvestments in Swedish nuclear power (more) profitable. With a 10% reduction of the investment costs, the model results show a significant increase of the reinvestment level, corresponding to an expansion of the nuclear power production by year 2050 by 40 TWh in the Climate scenario and no less than 60-70 TWh in the Reference scenario.
- If the Swedish nuclear power tax is reduced to the same level as in Finland, our sensitivity analysis shows a result similar to what we see from reducing investment costs by 10-20%.



Results from our sensitivity analysis, in which we have tested lowered investment costs by 10-20% for the nuclear power in the Reference and Climate Market scenarios. The volumes of the Nordic nuclear power production are shown in the left panel, and the total electricity generation in the Nordic countries can be seen in the right panel (from which the figures for the nuclear power production in the left panel are extracted). The sensitivity analysis´ result from an elimination of the Swedish capacity tax (with maintained high investment costs) is very similar to the result in these figures.

b) Wind power is the alternative to nuclear power, in Sweden as well as in the Nordic countries. If nuclear power is expanded, less of wind power will be developed and vice versa.

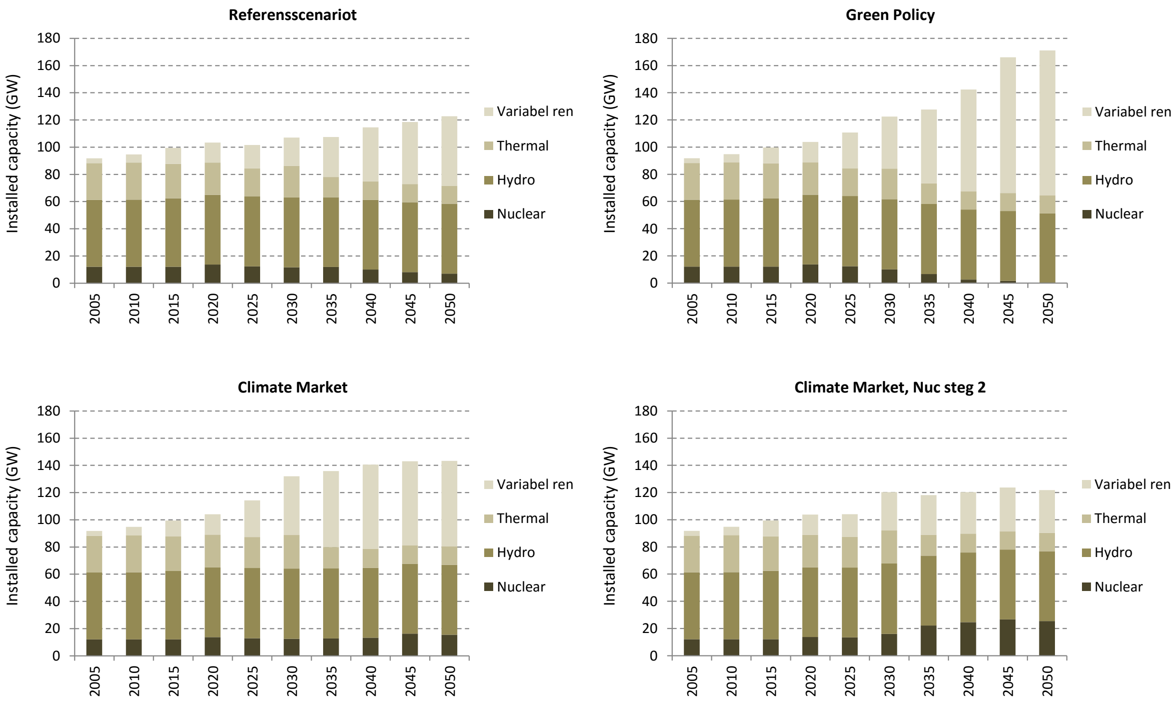
c) With nuclear power, the Swedish and the Nordic electricity generation - and the export – will be larger. The Swedish as well as the Nordic generation exceeds the domestic electricity demand in all scenarios with more nuclear power, which results in an increased export from Sweden and the Nordic countries in these cases. (The reason why the nuclear power is not expanded outside the Nordic countries is that it is not allowed in the scenarios, e.g. the German decommissioning decision.)

We must pay more attention to the electricity capacity issue, especially for the period after 2030

As new electricity generation is introduced in Sweden, the Nordic countries and Europe, large amounts of electricity production with low variable costs are added. This has a downward effect on the wholesale price of electricity, and makes it harder to finance investments and reinvestments in adjustable power, especially thermal power, i.e. nuclear power, or condensing power and cogeneration power plants fired with fossil or renewable fuels. In the scenarios with both an increased electricity demand and a reduced supply of adjustable electricity generation there will therefore be large challenges for the power system to handle.

Of the future changes that can be predicted for the Swedish power system, an increased share of wind and solar power is bringing the largest challenges. Wind and solar power have a number of features creating these challenges:

- They are not easily controllable, and are dependent on the sun shining, or the wind blowing. This is of significance in the short term as well as from a seasonal view.
- Wind prognoses are uncertain and reaches a high accuracy just a few hours ahead. The sun's movement across the sky is of course predictable, but the thickness of the cloud cover might have a large influence on the production of solar power which might vary significantly from day to day, and has proved hard to prognosticate.



Installed electricity generation capacity in the Nordic countries subdivided into different generation alternatives ("Climate Market, Nuc steg 2" is a scenario version where additional nuclear power is developed.) The largest challenge in the long run can be predicted for Green Policy, where the adjustable capacity amounts to 60 GW, whereas variable power (wind a solar power) amounts to more than 100 GW.

- Wind and solar power do not engage synchronous machines directly connected to the electricity system, and they will therefore not, without extraordinary solutions, provide the system with mechanical inertia or voltage regulation.

Consequently, it is of great importance that we pay increasingly more attention to this complex of problems in the future. And even if we can handle the situation without greater difficulties today, we must already now prepare for the challenges we might face 10-20 years from now. In a special NEPP theme book about the Swedish power system, we elaborate on these problems and we also discuss how these challenges can be met. We have identified eight challenges that require specific attention and these are briefly described below.

Challenges when there are large amounts of wind and solar power and a low demand

1. Mechanical flywheel capacity: During periods when conventional production is replaced by large amounts of solar power or classical wind power, the amount of mechanical inertia in the system will be smaller, since solar and wind power plants usually do not operate with synchronous machines directly connected to the electric system. Mechanical inertia is required to fend off disturbances in the electrical system.

2. Load balancing: With a larger amount of wind and solar power, the short term variations (seconds to hours) will be larger, which increases the need for balancing capacity. With a larger amount of wind and solar power, it will also more often happen that fewer conventional power plants are active in the system. Which means that fewer plants might have to share the load balancing burden, and that they must have enough margin to handle this.

3. Surplus situations: On sunny and windy days with a low demand, there might be a surplus situation that must be handled, especially if related markets are in the same situation and cannot absorb this surplus.

4. Transmission capacity: If large amounts of solar power is to be transmitted from Northern Sweden to the South and out on the international grid, while other synchronous generation is more or less idling, there is a need of other reactive compensatory mechanisms to maintain the voltage and thereby the transmission capacity in the main lines.

Challenges when there are small amounts of wind and solar power and a high demand

5. Available peak load capacity: With a larger amount of wind and solar power capacity, there will be situations with high electricity demand and low wind and solar power generation. Enough capacity is needed also for these situations.

General challenges in keeping the balance

6. Increased needs of flexibility in adjustable generation and consumption:

- Wind power generation can be assumed to have the same variability as the demand has today. The demand varies in a regular and predictable way, whereas the wind power fluctuates following a stochastic pattern. This poses a challenge to the planning of hydropower generation with patterns and volumes different to what the river sections of today were designed for.
- The physical regulation capacity and the regulatory system for hydropower are designed to handle the current regular variations in demand.
- Hydrological circumstances and water-ecological considerations in different river parts, limit the possibilities for a fast re-planning of the water regulation.
- A larger amount of hard-to-prognosticate wind and solar power makes it more difficult to plan the hydro power along a river part and the usage of the transmission grid. The increased uncertainty may lead to both the generation and the transmission needing to be planned more conservatively and with larger margins.

7. Adaption of the distribution of responsibilities and of the market mechanisms: The sharing of responsibility and burden between the actors in the electricity system, with the aim to maintain the physical balance and the market mechanisms available to support this, are all designed to fit the current needs. The increased and modified regulation needs might mean that the current models for cooperation and for the market will not be adequate. They might rather form an inefficient regulatory system. If the responsibility to manage the increased prognosis uncertainties is assigned to the actors on the market, a development might be required towards a large part of the electricity trade being made closer to real time. An alternative is that a larger part of the load balancing is handled by the system operator and that the procurement of regulation services is extended.

8. Annual regulation: If solar power becomes a substantial part of the power system, it will call for an extended inter-seasonal storage, since a major part of the generation takes place when the demand has a low season.

For these eight challenges there are a large number of potential (partial) solutions. There are good reasons to believe that also a power system with a very large share of variable electricity generation might be well-functioning. But insight into the challenges and the ability to implement the solutions are necessary for this to happen.

In a special NEPP theme-book about the Swedish power system (NEPP 2014b), we elaborate on these problems and discuss how the challenges can be handled.

References

CDC Climat Recherce (2013), “Tendances Carbone”, Oct 2013, available at http://www.cdcclimat.com/ IMG//pdf/cdc_climat_recherche_tendances_carbone_no_84_fr.pdf

E3Mlab of ICCS/NTUA, 2011, “PRIMES Model”, Ref. Ares(2011)830214-29/07/2011, available at http://ec.europa.eu/energy/energy2020/roadmap/doc/sec_2011_1569_2_prime_model.pdf

EC (2001), Directive 2001/80/EC of the European parliament and of the council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants.

EC (2003), Directive 2003/87/EC of the European Parliament and of the Council establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC.

EC (2007), ”European energy and transport, trends to 2030 – update 2007”

EC (2008), Commission staff working document, “The support of electricity from renewable energy sources”, {COM(2008) 19 final}, available at http://ec.europa.eu/energy/climate_actions/doc/2008_res_ working_document_en.pdf

EC (2009a), Directive 2009/29/EC of the European Parliament and of the Council of 23 April 2009 amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community.

EC (2009b), Decision No 406/2009/EC of the European Parliament and of the Council of 23 April 2009 on the effort of Member States to reduce their greenhouse gas emissions to meet the Community’s greenhouse gas emission reduction commitments up to 2020.

EC (2009c), Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC (”Renewable energy Directive”).

EC (2011a), Communication from the commission to the European parliament, the council, the European economic and social committee and the committee of the regions, “A Roadmap for moving to a competitive low carbon economy in 2050”, com/2011/0112 final.

EC (2011b), Impact assessment, Accompanying document to the communication from the commission to the European parliament, the council, the European economic and social committee and the committee of the regions a roadmap for moving to a competitive low carbon economy in 2050, SEC(2011) 288 final.

EC (2011c), Commission staff working paper, Impact assessment accompanying the document communication from the commission to the council, the European parliament, the European economic and social committee and the committee of the regions energy roadmap 2050, sec(2011) 1565/2.

EC (2012), Directive 2012/27/EU on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC.

EC (2013a), “GREEN PAPER - A 2030 framework for climate and energy policies”, COM(2013) 169 final.

EC (2013b), EU Energy, “Transport and GHG Emissions Trends to 2050, Reference Scenario 2013”.

EC (2013c), Report from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions — Renewable energy progress report, COM(2013) 175 final (http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri= CELEX:52013DC0175:EN:NOT), accessed 2 October 2013.

EC (2014a), COM(2014) 15 - Communication: “A policy framework for climate and energy in the period from 2020 to 2030”.

EC (2014b), Questions and answers on the proposed market stability reserve for the EU emissions trading system, January, 22, 2014, MEMO-14-39.

EC (2014c), “Structural reform of the European carbon market”, available at: http://ec.europa.eu/clima/ policies/ets/reform/index_en.htm, downloaded 2014-01-22.

EC (2014d), information on the EU ETS available at
http://ec.europa.eu/clima/policies/ets/index_en.htm 2014-04-10.

EC (2014e), Questions and answers on 2030 framework on climate and energy, January, 22, 2014, MEMO-14-40.

EC (2014f), information available at http://ec.europa.eu/energy/efficiency/.

EC (2014g), "EU Climate Change Committee agrees back-loading", available at: http://ec.europa.eu/clima/policies/ets/reform/index_en.htm, downloaded 2014-01-22.

EC (2014i), *Energy Efficiency and its contribution to energy security and the 2030 Framework for climate and energy policy*, COM(2014) 520 final, European Commission, Brussels, 2014.

EEA (2013), European Environment Agency ,"Trends and projections in Europe 2013 Tracking progress towards Europe's climate and energy targets until 2020", EEA Report No 10/2013, ISSN 1725-9177.

EEA (2014a), European Environment Agency , "EEA greenhouse gas - data viewer", available at: http://www.eea.europa.eu/data-and-maps/data/data-viewers/greenhouse-gases-viewer, version November 2014.

EEA (2014b), European Environment Agency , "Why did greenhouse gas emissions decrease in the EU between 1990 and 2012?" available at: http://www.eea.europa.eu/publications/why-are-greenhouse-gases-decreasing, downloaded 2014-11-10.

Euractive (2014a), "Energy Efficiency Directive: Completing an energy policy puzzle", article available at http://www.euractiv.com/energy-efficiency.

Euractive (2014b), "Parliament backs strong EU stance on 2030 clean energy goals", article available at http://www.euractiv.com/energy/meps-confirm-ambitious-stance-20-news-533298, 10/4 2014.

Euractive (2014c), "Big EU guns fire for 'crucial' 2030 renewable targets", article available at http://www.euractiv.com/energy.

European Parliament (2014), REPORT on a 2030 framework for climate and energy policies (2013/2135(INI)) Committee on the Environment, Public Health and Food Safety, Committee on Industry, Research and Energy.

Eurostat (2015), Eurostat Statistics Database, http://ec.europa.eu/eurostat/data/database, Eurostat, Luxembourg, 2015:

- Final energy demand and Primary energy demand (table: nrg_100a) http://appsso.eurostat.ec.europa.eu/nui/show.do?wai=true&dataset=nrg_100a
- GDP and main components – volumes (table: nama_gdp_k) http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nama_gdp_k&lang=en
- Supply, transformation and consumption of electricity - annual data (table: nrg_105a) http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_105a&lang=en

Financial Times (2013), "UK agrees nuclear power deal with EDF ", article available at http://www. ft.com/cms/s/0/00eff456-3979-11e3-a3a4-00144feab7de.html#axzz2xuFlrXDj 2014-04-04.

Fraunhofer (2013), "Stromgestehungskosten erneuerbare energien" (in German).

Fraunhofer (2012), "Stromgestehungskosten erneuerbare energien" (in German). Fraunhofer (2010), "Stromgestehungskosten erneuerbare energien" (in German).

Fraunhofer (2014), "Recent Facts about Photovoltaics in Germany", available at http://www.ise. fraunhofer.de/en/publications/veroeffentlichungen-pdf-dateien-en/studien-und-konzeptpapiere/recent-facts-about-photovoltaics-in-germany.pdf 2014-04-03.

Fraunhofer (2014b), „Study evaluating the current energy efficiency policy framework in the EU and providing orientation on policy options for realising the cost-effective energy efficiency/saving potential until 2020 and Beyond, Country Annex 2: Decomposition Analysis", 19 September 2014, Available at: http://www.isi.fraunhofer.de/isi-en/x/projekte/PolicyEval_Framework_331252.php

Handelsblatt (2014), article in Handelsblatt 2014-04-02 (in German), available at http://www.handelsblatt. com/meinung/kommentare/kommentar-zur-energiewende-gabriels-refoermchen/9704876.html.

IEA/Nordic Energy Research (2013), "Nordic Energy Technology Perspectives", ISBN: 978-82-92874-24-0.

IEA (2012), World Energy Outlook 2012, OECD/IEA. IEA (2013), World Energy Outlook 2013, OECD/IEA.

IEA-PVPS (2013), ” National Survey Report of PV Power Applications in Sweden”. Task 1 : Exchange and dissemination of information on PV power systems. IEA co-operative programme on photovoltaic power systems.

Kjärstad J., Morbee J., Odenberger M., Johnsson F. and Tzimas E. (2013), “Modelling large-scale CCS development in Europe – linking techno-economic modelling to transport infrastructure”, Energy Procedia.

Maddison (2013), The Maddison-Project database, http://www.ggdc.net/maddison/maddison-project/home.htm, 2013 version, University of Groningen, Groningen, downloaded November 2014.

Miladinova G. (2013), “New EU energy efficiency policies & How to measure the progress?”, taken from a presentation Source: European Commission (taken from a presentation by Miladinova G, June 2013)

NEPP (2014a), NEPP-report, “Three principal factors explain at least three quarters of the greenhouse gas reduction in the EU between 1990 and 2013”, available at: www.nepp.se

NEPP (2014b), NEPP-report (in Swedish), “Reglering av ett framtida svenskt kraftsystem”, available at: www.nepp.se

NEPP (2015a), NEPP-report (in Swedish), “Development of the power system in Sweden, the Nordic countries and Europe”, available at: www.nepp.se

Point Carbon (2013), “What have we learnt from the EU ETS? Does the current low price shows that the ETS has played its role?”, presentation at the NEPP seminar, October 13

RES LEGAL Europe (2014), website on regulations on renewable energy generation, available at http:// www.res-legal.eu/search-by-country/ 2014-04-10.

Svensson, R., Odenberger, M., Johnsson, F., and Strömberg, L. (2004). ”Transportation systems for CO2 - Application to carbon capture and storage”. Energy Conversion and Management, 45 s. 2343-2353. : Elsevier Ltd. [Nr. 5114]

WEC (2013), “World Energy Perspective Cost of Energy Technologies,” World Energy Council (WEC), Project Partner: Bloomberg New Energy Finance.

Worldbank (2014), The World bank database, http://data.worldbank.org/indicator , The World Bank Group, downloaded November 2104.

World Nuclear Association (2014), country profiles, available at http://www.world-nuclear.org/info/Country-Profiles/, 2014-03-11.