north european power perspectives

NEPP mid-term report

May 2012

The NEPP mid-term report

The purpose of this report is to present some of the analyses, results and conclusions that have emerged during the first half of the NEPP project. The analyses and results are presented in short chapters dealing with different aspects of the development of the European energy systems. The Nordic/North European region and the electricity system are focus areas.

The findings are also presented as "twelve statements" that summarize these analyses and results in a way that also provides a summary of the research carried out during the first half of the project. Some of the twelve statements are the key results referred to above, while other statements are hypotheses based on the analyses carried out so far in the project. These hypotheses will be further analysed in the second half of the project.

The NEPP Research Group:

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CONTENT

1. TWELVE EARLY STATEMENTS

This research report contains analyses and results form the project North European Power Perspectives (NEPP). The purpose of the report is to present some of the key results and conclusions that have emerged during the first half of the project.

The findings are presented as twelve statements that summarize these results in a way that also provides a summary of the research carried out during the first half of the project. Some of the statements are the key results and conclusions referred to above, while other statements are hypotheses based on the analyses carried out so far in the project. These hypotheses will be further analysed in the second half of the project.
Since the project is only halfway to completion, all results and conclusions, as well as the hypotheses, must be regarded as preliminary. All results, conclusions, and hypotheses will be further studied in the second half of the project.

RESTRUCTURING THE ENERGY AND ELECTRICITY SYSTEMS BY 2050 IS A CONSIDERABLE CHALLENGE

1

Our project has developed a new methodology, based on the scorecard principle, for evaluating the difficulties in restructuring the electricity and energy systems by the year 2050. The methodology has been used to evaluate the difficulties in meeting the goals set out by the European Commission in its Energy Roadmap 2050, and has also been applied to our four NEPP scenarios. Both the Roadmap and all NEPP scenarios assume very large reductions in greenhouse gas emissions. Three possible conclusions from our evaluation are:

- The challenges are so great that the likelihood of fully reaching all targets is low.
- All scenarios and roadmaps are more or less equally challenging.
- The challenges ahead (2012 to 2050) are far greater than the difficulties that were encountered during the period 1970-2012.

Some of the proposed measures are very uncertain

One of the significant challenges facing the EU is the introduction of Carbon Capture and Storage (CCS) and the development of CO_2-infrastructure, i.e. sites suitable for the long-term storage of CO_2. CCS has not been applied at large scale anywhere in the EU, and public acceptance for the technology seems to be very low. Whether CCS is available at large scale in the next 20-30 years is therefore highly uncertain.

It is also highly uncertain if the system will deliver the necessary generation capacity and transmission infrastructure required for an electricity sector dominated by intermittent renewables. Equally uncertain is the Roadmap's ambition to electrify the transport sector, as it entails replacing nearly all vehicles and building a new electric transportation infrastructure from scratch. Many of the underlying technologies are close to the point where they become commercially feasible, but it is important to realize that the challenges in electrifying the transport sector by the year 2050 are very significant.

Numerous stakeholders consider increased energy efficiency a key measure. As it turns out, increased energy efficiency does not figure as prominently in the Roadmap as in for instance the IEA scenarios. Furthermore, experience from Sweden and other countries shows that it is very difficult even for the profitable energy efficiency measures to get implemented.

2 NEW POLICY INSTRUMENTS WILL BE NECESSARY, AND THEY NEED TO BE MORE POWERFUL THAN THE ONES IN USE TODAY

In the remainder of the project the scorecard methodology will be further developed to refine the analyses of the challenges in restructuring the electricity and energy systems. A further goal is to develop the methodology so that it can also be used to shed light on what government policies related to the restructuring of the energy system will look like in the future, provided that the restructuring is fully carried out.

One NEPP hypotheses – which will be further analysed during the second half of the project – is that current policy instruments are inadequate for the challenges ahead. The current set of policies may be adequate for some of the minor challenges, but to overcome the major challenges new and more forceful policy instruments will be required. For instance, it is highly unlikely that CCS will be introduced on a large scale without new and powerful government policies.

Using an extended version of the scorecard methodology, we hope that we will be able to determine to which extent the following statements are true:

- Large parts of the restructuring will require new and very forceful policy instruments.
- Policies based on financial incentives and other conventional policy instruments are inadequate

3 SIGNIFICANT REFORM OF ELECTRICITY MARKETS MAY BE REQUIRED

The Nordic electricity market was primary designed to utilize existing resources as efficiently as possible – the ability to replace large parts of the electricity system at lowest possible cost to electricity consumers was never a stated goal of the market design.

This design has worked well for the past 15 years, and the efficiency of the electricity system has in many ways improved. The short-term optimization of the system (dispatch of generation units in merit order) is working well. Cross-border trade has increased over the years, and some excess capacity has been closed down. Customers are beginning to be part of the short-term optimization through spot price-linked contracts, and it has not been possible to show any significant abuse of market power. New market-based policy measures like the EU-ETS have worked as designed: the wholesale price of electricity has increased, as one would expect when the short-run marginal cost is setting the price. However, the ability of the Nordic market design to underpin long-term investment has not yet been fully tested.

Yet, the nature of the European generation mix is undergoing a profound change as a result of European climate change and renewable energy policy, and it is not immediately clear that the Nordic market design is the most suitable for the energy systems of the future, especially if the transformation of the electricity system is to be carried out at minimum cost to electricity consumers.

There are three main aspects to consider when analysing this issue; risk, coordinated investment decisions, and costs to consumers:

- The risks associated with investments in generation capacity and transmission under the current market design are rather high, and the risk will increase as the share of renewables connected to the system increases. In addition to electricity market risk, there is also a price risk stemming from the carbon market.
- The existing Nordic market design does not provide an adequate solution for how to best coordinate transmission and generation investment decisions.
- Market pricing in electricity markets is equivalent to short-run marginal cost pricing. This is an efficient way to price electricity when it comes to short-term utilization, but can at the same time increase costs to consumers compared to other pricing schemes. This would most likely be the case when there are significant needs for new investment.

REFORMATION OF THE EUROPEAN ELECTRICITY MARKETS IS AT A CROSS-ROADS - MORE MARKET OR MORE PLANNING

4

- *If a more market-oriented approach is selected, capacity markets and nodal pricing should be considered.*

The target model for the single European market is being challenged even before it is implemented. Large amounts of electricity generation from renewable energy sources will change the market conditions. The European electricity markets reform is at a crossroads.

The variable and intermittent nature of renewable generation means that it cannot be depended on to meet demand reliably. As a result, large amounts of renewable generation will have to be complemented by large amounts of flexible thermal generation, so the overall installed capacity to meet a certain demand will be higher than in today's electricity markets. The risk of not being dispatched faced by conventional generation with higher marginal costs will increase, and more conventional generation will be idle for longer periods. In addition, for periods when the renewable output is high, the market's clearing price will be lower as large amounts of near zero marginal cost generation will likely depress the wholesale price of electricity. To compensate for fewer running hours and lower prices, conventional generation is likely to resort to offering its generation to the market at costs significantly above short-run marginal costs when the wind is not blowing and demand is high, leading to increased price volatility and occasional extreme prices significantly above the "normal" cost of the price setting unit. This may alienate the public, and may put pressure on politicians to intervene. Revenue uncertainty will increase, investments in electricity generation capacity will become riskier, and the cost of capital will go up, jeopardizing investment.

In four Market Design scenarios we will analyse the appropriate response to these new challenges. Will it be possible to keep the current market design with only "minor" adjustments, like increased demand flexibility, or is there a need for more interventionist approaches aimed at reducing the risk to generators and requiring a more fundamental redesign of the market?

We will analyse four Market Design scenario:

1 **Energy-only** (the Nordic market model for Europe)

2 **Capacity market** (addition of a separate capacity market creating income for capacity even if not used)

3 **Locational Marginal Pricing** (a combination nodal pricing that incorporates the costs for network losses and network congestion into electricity prices and locational capacity markets)

4 **Detailed regulation** (increased central planning and consumer price based on average cost)

Currently it seems like several European countries are opting for redesign and are planning reforms not envisioned by the European target model. For instance, several countries are opting for different types of capacity mechanisms to reduce reliance on price spikes to recoup capital costs. Both the UK and France have decided to introduce sector-wide quantity based mechanisms by 2015. Poland and Italy have similar plans, and Germany is currently discussing the issue. Poland is also planning to introduce Locational Marginal Pricing to facilitate investment decisions through more efficient locational price signals.

In addition to concerns about the financing of generation investments, there are several other issues to be considered. Large variations in generation over both time and space will further strain electricity networks, thus making both efficient expansion and utilization of the grids increasingly important. Demand side engagement should be encouraged and improving locational price signals should be investigated.

5 WE MUST ANALYSE THE POSSIBILITY TO USE EXISTING RESOURCES FOR MORE BALANCING PURPOSES IN PARALLEL WITH THE INVESTMENT ANALYSE FOR NEW RESERVE CAPACITY

As the volume of variable renewable generation such as wind power and solar power continues to increase, more flexibility in the form of modified generating schedules for other units or more demand flexibility will be required in order to continually balance the electricity system to match supply and demand.

Not all reserve capacity resources are equally flexible, i.e. can be activated to provide balancing energy equally fast. It is therefore useful to look closer at what we mean by "need" and "reserve capacity" when analysing the "need for reserve capacity".

When analysing "reserve capacity", it is also important to separate between variability and uncertainty:
- Variability - which is obtained from load changes and wind and solar power changes.
- Uncertainty - which is obtained from the difference between forecasts and real outcome for load, wind/solar power, thermal power and interconnections.

Concerning "needs" it is important to consider the distinction between technical and economic needs, and that there is a competition between three technologies/options:
- Production flexibility
- Consumption flexibility
- More and flexible transmission

Our analyses lead to the following results and statements so far:
- More wind and solar power will increase the need for reserves, but not automatically result in a comparable need for investments.
- The big question is what will happen with existing firm capacity in the system. Will it be kept or will it be decommissioned due to few expected operation hours adding to the need of an increased strategic reserve or other market design initiatives.

The effect of cross border trading cannot be ignored when new generation is considered

In the debate surrounding new investment in renewable generation, especially wind power, it is common to hear statements like "X TWh of additional low marginal cost generation capacity in Sweden will depress Swedish electricity prices by Y SEK/MWh". Often, the effects of cross-border trading are overlooked, but the validity of such statements cannot be properly assessed without considering the impact of cross-border trading.

To verify if such a statement is true or false, the usual procedure is to compare the "original" system with the "new system", i.e. the original system + X TWh. The "consequence" of additional generating capacity is then given by the difference between the results obtained by running these two different scenarios. When modeling, the following properties of the Swedish electricity system have to be taken into account:

a) Demand, not being very price sensitive, will be about the same in both scenarios.
b) Electricity generation in the other Swedish units, except hydro power scheduling, remains roughly the same. This is because foreign thermal price-setting units have higher marginal costs than Swedish price-setting units, so any additional cheap Swedish generation will primarily displace foreign price-setting units.
c) Hydropower resources will be scheduled differently depending on whether the additional capacity (X TWh) is wind, nuclear or CHP.

In summary, the accuracy of the statement "X TWh of additional generation capacity will depress electricity prices by Y SEK/MWh" will depend on several factors, most notably the steepness of the supply curve of the electricity systems to which Sweden is interconnected. This is valid for all additional generating capacity with low short-run marginal costs and is not limited to wind power.

CONVENTIONAL TECHNOLOGY IS A KEY PLAYER, WHILE TRANSMISSION GRID AND CCS INFRASTRUCTURE ARE CRITICAL

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The model analyses conducted so far clearly indicate that far-reaching climate-policy targets within the European electricity generation system can be fulfilled with, to a large extent, relatively conventional technology. Even though the share of renewables steadily increases over time in the model runs, a very large contribution may still originate from fossil fuels in the future. The key to this is the assumed availability and commercialisation of CCS technology. In the main scenarios analyzed so far, CCS schemes account for 30-50 percent of total electricity supply in 2050, depending on the region (the sole exception is the Nordic region where renewables are the main providers of electricity and CCS is not profitable). This is, of course, a very important precondition. If, for some reason, CCS will not become commercialized during the coming decades, the development of the European electricity-generation system will be significantly different from what has been shown hitherto, given ambitious climate targets.

However, regardless of whether CCS becomes commercially viable or not, the dramatic change in electricity supply towards low CO_2 emissions will inevitably lead to significant investments in supply-related infra-structures. In the case of CCS, this would include investments in CO_2 transportation and disposal. In the case of renewables such as wind power this may include large reinforcements of electricity transmission and distribution grids. In some scenarios and European regions the future demand for biomass becomes of substantial size. Even though it may be achievable from a supply-side point of view such as development will undoubtedly imply major logistic and infra-structural challenges.

Since the lion share of the technologies identified in the future development of the European electricity-supply system may be characterized as ”conventional”, the key challenges ahead lie less in the technologies per se but rather in the task of putting them altogether into a secure and clean system that provides us with energy at reasonable costs. Even CCS consists of relatively known and proven technology – the challenge is to merge it together into an efficient large-scale electricity-generation system. Such challenges include not only infra structural challenges but also other important factors such as public acceptance. A mixed balance including many technological options and resources is, therefore, desirable not only from a security-of-supply perspective, but also due to the fact that a very large single share of each and one of the key technologies identified here (CCS, biomass, wind power, nuclear power etc) requires enormous investments in infra structure and may be negatively perceived in the eyes of the public opinion.

ELECTRICITY PRICES ARE EXPECTED TO RISE – BUT CARBON PRICES AND CERTIFICATE PRICES RISE EVEN MORE

7

The four NEPP electricity system scenarios show different electricity price development. There is however, one thing in common; increasing prices. When we discuss electricity prices it is in specific situations important to make a distinction between system prices (wholesale prices) and final use prices (retail prices). The difference appears when we apply a support system (e.g. a certificate system) to support renewable electricity generation. In that case the final users, in addition to the system price of electricity, will have to pay for a fraction of the electricity certificate. The electricity price, including possible certificate fees, typically reaches 600 – 800 SEK/MWh by the year 2050 (compared to around 400 – 500 SEK/MWh today). As could be expected the electricity price is typically higher in scenarios with the most ambitious renewable energy and/or climate ambitions. (Prices are discussed in more detail in Chapter 3.)

If we in the scenarios where a certificate system is applied assume that – like today - only a fraction, approxima-tely 50 %, of the electricity users would be included in the electricity certificate system and forced to pay for a fraction of the electricity certificates, the retail price would of course increase even further. Here the long term electricity price reaches 1000 – 1200 SEK/MWh. The other electricity users can in these cases enjoy fairly low electricity prices.

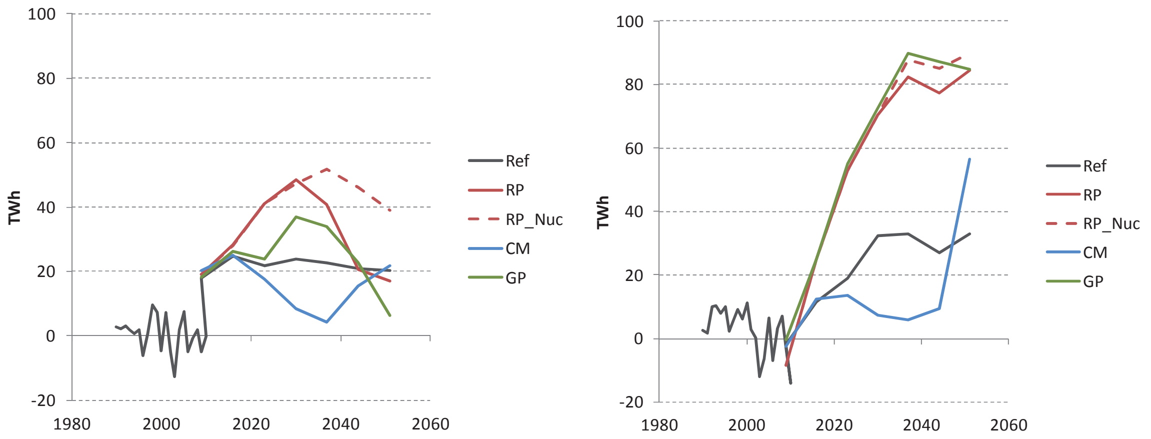
In order to reach a development that is in line with e.g. the 2 degree climate target, very high levels of CO_2 prices will be needed, especially if this is the only policy instruments applied. Our ELIN model runs indicate long term levels of 150-280 €/ton. (This could be compared to the present levels of less than 10 €/ton).

One way of moderating the CO_2-price is to introduce additional policy instruments, e.g. for the promotion of renewable energy. In the NEPP scenarios two of the scenarios include a European electricity certificate system. The high renewables ambitions results in marginal costs for such certificates in the range of at least 300 – 500 SEK/MWh (as described above).

8 SWEDEN WILL BECOME THE LARGEST ELECTRICITY EXPORTER IN NORTHERN EUROPE. WHAT ABOUT THE ROLE OF NUCLEAR POWER?

In the NEPP scenarios the Swedish net electricity export constitutes a dominating part of the common Nordic export up to around 2030.

As seen in the figure the Swedish net export is typically in the range of 20 – 30 TWh/year by 2030, with extremes of 5 – 50 TWh/year. A combination of constant use of nuclear power and strong support for renewable electricity generation facilitates this large export. But the Swedish share of Nordic export decreases significantly in the scenarios, when all Swedish nuclear energy is phased out.



Net electricity export in the four scenarios (Sweden to the left and the Nordic region to the right)

In all scenarios Sweden and the Nordic region act as net exporters of electricity. The Nordic export reaches 80 TWh by 2040, in two of the scenarios (Regional policy and Green policy). At the Nordic level it is interesting to note that the effect of large efforts to expand renewable generation is more important than the effect of continued use of nuclear power. The two NEPP scenarios with nuclear phase-out in Sweden both include strong support systems for renewable electricity generation, and the effect of these policy instruments create more electricity generation than is lost through nuclear phase-out. The scenarios with low or moderate long term support for renewable electricity, results in lower net Nordic electricity export for different reasons, even if nuclear power is kept constant at a high level. The Reference scenario is characterized by low electricity demand and a lack of long term support for renewable electricity. The Climate market scenario combines high domestic Nordic electricity demand and moderate expansion of renewables.

Nordic electricity production: production levels not expected to change dramatically; the challenge lies in ensuring sufficient capacity

The Regional policy and Green policy scenarios are characterized by a decrease in thermal production in favour of variable, and partly intermittent, renewable generation. These generation sources have a certain lack of predictability and reduced capacity value in common. In the Green policy scenario such generation amounts to 55 % of the total Nordic generation in 2050. This forms certain challenges for the electricity system that is discussed in Chapter 3.

This structure of the electricity generation in the Nordic system is problematic from capacity point of view, especially since we foresee a similar development in the rest of Europe. Will market prices on an “energy only market” be sufficient enough to give incentives to build the necessary reserve capacity? This could create a situation with reduced delivery security and/or extreme price volatility. One solution to this is to establish a capacity market. This is discussed further above, and in Chapter 4.

ELECTRIC VEHICLES ARE IMPORTANT FOR A DECARBONIZED TRANSPORT SECTOR – BUT THE EU DOES NOT BELIEVE THAT THE TRANSPORT SECTOR WILL BE LARGELY ELECTRIFIED IN THE NEXT 20 YEARS

9

Electric vehicles, including plug-in hybrids, is an important alternative for the transformation of the transport system. In Sweden we have an ambition to make this change during a short period, in order to make the transport vehicle fleet independent of fossil fuels by 2030. This puts great demand on introduction of electric vehicles and indirectly on the electricity system. In the Swedish Transport Administration´s most ambitious scenario (”Målbild för ett transportsystem som uppfyller klimatmål och vägen dit”, report 2012:105) they assume 1 000 000 electric vehicles by 2030. This puts special focus on the capacity situation and a number of studies are made within the NEPP project to evaluate the impact on the electricity system and on the electricity market.

Simultaneously we can see that our Swedish ambition regarding a rapid transformation of the transport system is not in line with the EU target. The EU Roadmap shows a much more moderate transformation to 2030, and specifies the period 2030 – 2050 as the main transformation period for the EU transport system.

THE CLIMATE TARGETS IN THE NORDIC REGION (AND THE EU) ARE MORE FAR-REACHING THAN THOSE SPECIFIED BY IEA IN ETP 2012

10

NEPP is the Swedish partner in the IEA project to develop a Nordic ETP – a Nordic subproject of the IEA global project called ”Energy Technology Perspectives”. The main scenario in the global ETP is a “two degrees scenario” where by 2050 global emissions are reduced by 50 % compared to 2009 levels.

For the EU, IEA calculations point to carbon emissions that in the year 2050 are 60 % lower than in 2009. However, the main scenario in the Roadmap is about an 85 % reduction in greenhouse gas emissions.

For the Nordic region, IEA foresees in its main scenario that greenhouse gas emissions will be reduced by 60 % between 2009 and 2050. It should be noted that this reduction is much lower than current national targets. For instance Sweden has a climate goal that states that “Sweden should not have any net greenhouse gas emissions by the year 2050”.

According to the IEA, this difference in the target levels is based on a difference in how the global target is allocated among countries and regions. The IEA allocates less of the total target to the EU than the EU itself does.

THE EU MAY FAIL TO REACH ITS 2020 RENEWABLES TARGET

11

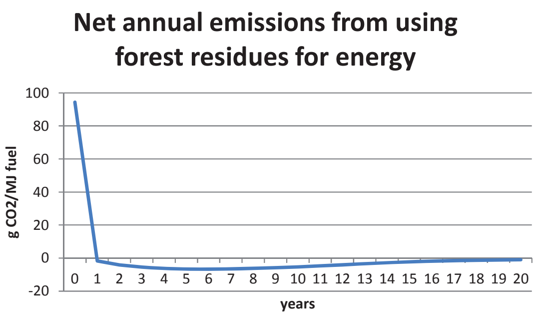
At present, the official line from the EU and Member States is that the EU will reach its targets to reduce greenhouse gas emissions by 20 % and increase its share of renewables to 20 % by the year 2020. The national Progress Reports on the promotion and use of energy from renewable sources and describing the Member States’ progress in increasing their use of renewable energy show that the renewable sub-targets for the year 2010 were reached. Emissions reduction progress reports were also positive. However, analyses performed by NEPP show that the optimism about the renewables target might be misplaced.

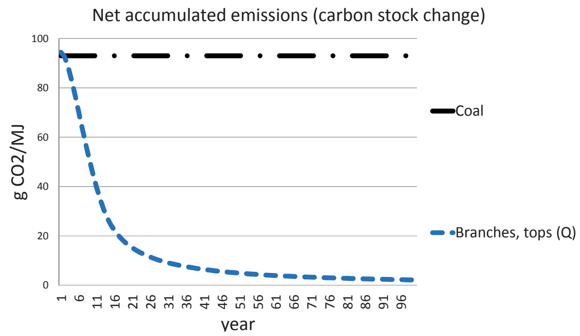
NEPP believes that it is far from certain that the EU will reach its 20 % renewables target by the year 2020. This belief does not stem from scepticism over the renewable energy increase. It is based on the belief that Member States will not be able to reduce growth of overall energy demand sufficiently to reach the goal. The renewables target is a relative target – the amount of renewable energy production divided by the total use of energy (expressed as final energy).

However, given our analysis of the link between total energy demand and fulfilment of the renewables target, we believe that a new Energy Efficiency Directive may contribute to the fulfilment of the renewables target. It may even be necessary to have a more robust Energy Efficiency Directive in place for the EU to reach its renewables target.

12 BIOFUELS ARE NOT CLIMATE NEUTRAL – BUT THEY ARE STILL IMPORTANT IN A LOW-CARBON ENERGY SYSTEM

When biomass is combusted the carbon that once was bound in the growing biomass is released, thus closing the biogenic carbon cycle. For this reason bioenergy is often considered CO_2 neutral. For instance, CO_2 emissions from the combustion of bioenergy are not included in the EU ETS. However, bioenergy production may influence biogenic carbon stocks and atmospheric CO_2 significantly in either a positive or negative way. Using logging residues or stumps for energy instead of leaving them in the forest, will lead to an instant release of carbon to the atmosphere. However, this effect is of transient character. If forest residues or stumps are left in the forest, the major part will decompose over time and release carbon to the atmosphere. The net effect of using forest residues for energy can therefore be described as a pulse emission at t= 0, which is compensated over time due to the avoided emissions from leaving the residues on the ground to decompose, see figure below.





Net annual emissions (left) from using forest residues as fuel and net accumulated emissions (right).

The accumulated climate effect is obtained by integrating the diagram over time. This is done in the figure above (right) and compared to the corresponding graph for using coal. The figure shows that over a 100 year perspective the use of branches and tops are close to being carbon neutral. Over 10 years, however, the net CO_2-emissions are approximately 40 % of those from using coal for energy. The climate impacts of biofuels due to how they influence carbon stocks over time can be implemented in models in different ways:

1. **Either neutral or not.** A biofuel is considered carbon neutral if the time integrated carbon emissions, over a given time perspective (as calculated by principle 2 below) are lower than predefined value.
2. **Time integrated emissions**. Emissions are integrated over a given time perspective, for instance over 20, 50 or 100 years and this value is attributed to the biofuel. For instance for forest residues the integrated emission factors would be approximately 15, 5 and 2 g CO_2/MJ fuel for 20, 50 and 100 year time perspectives respectively.
3. **Time dependent emission factors**. The annual emissions and uptake, as presented in figure 2 are used. In other words, if 1 MJ forest residues are combusted there will be an instant release of 94 g CO_2 at t=0, followed by annual uptake of CO_2 from year 1 and forward.

2. The development of the European electricity system

Assuming significant CO_2-reductions in the European electricity system - around 80 percent by 2050 – leads to a dramatic change in the electricity supply of Europe. The share of renewables is expected to increase by around 25 percent by 2020 as a result of meeting the EU renewable target. Depending on scenario assumptions CCS, nuclear power and conventional gas power takes different market shares beyond 2020. Furthermore, depending on regional resources, policies and already decided investments, significant differences between European regions will remain also in a long term perspective.

2.1 The ELIN model

The analysis has primarily been carried out by using the ELIN model. The model covers the entire electricity-supply system in EU-27 (on a country-by-country basis) plus Norway and Switzerland. The time horizon spans 2003 (starting year) to 2050. The model includes the lion share of existing power plants (data taken from the Chalmers Power Plant Database) and a comprehensive menu of new technologies for investments. Existing power plants are phased out according to assumptions on remaining life times (age distribution of existing power plants is a key feature of the Chalmers Power Plant Database). Assumptions on technical life times vary among technologies - 85 yrs for hydro, 60 yrs for nuclear, 40 yrs for coal and lignite, 30 for gas, 25 yrs for wind. Especially in Eastern Europe a large part of the existing capacity consists of power plants of substantial age.

2.2 European outlook

The development of the European electricity generation in the two NEPP main scenarios, the Regional Policy and Climate Market scenarios, are presented in Figure 2.1 (Climate Market scenario) and Figure 2.2 (Regional Policy scenario). It is shown that almost half of the existing capacity is phased by 2030 out due to the assumed technical life times but also due to climate and renewable policies. In combination with the assumption on increasing electricity demand (slowly in the Regional Policy scenario and more rapidly in the Climate Market scenario) this leads to a significant need for new investments. The assumed renewable target in the Regional Policy scenario implies that renewable electricity exhibits a substantial capacity increase during the coming decades. But also in the Climate Market scenario the penetration of renewable is substantial, especially towards the end of the period when marginal costs for CO_2-reduction are getting large. The distribution between wind power and biomass power is relatively equal in terms of produced electricity. Depending on scenario assumptions investments in non-renewable electricity generation are divided among conventional gas and coal power, CCS schemes and nuclear power. The Climate Market scenario shows a substantial increase in gas power in the short to medium term. In a longer time perspective, gas power looses much some of its competitiveness due to increasing gas prices and increasing marginal costs for CO_2 -abatement. Gas CCS is, generally, not a profitable option in the model runs. Marginal costs for CO_2 reduction are higher in the Climate Market scenario due to larger electricity demand, more costly CCS and nuclear power at the same time as the reduction target expressed as Gt of CO_2 is the same as for the Regional Policy scenario.

Typically, marginal costs for electricity generation are around 65-85 EUR/MWh in the Regional Policy scenario and 70-90 EUR/MWh in the Climate Market scenario depending. However, significant differences between Member States may exist (see more in Chapter 2.5 concerning the role of new interconnectors). Furthermore, a typical income from the renewable target defined in the Regional Polcy scenarios is around 15-25 EUR/MWh. This means that renewable electricity generation gain a total "income" of approximately 90-100 EUR/MWh in the Regional Policy.

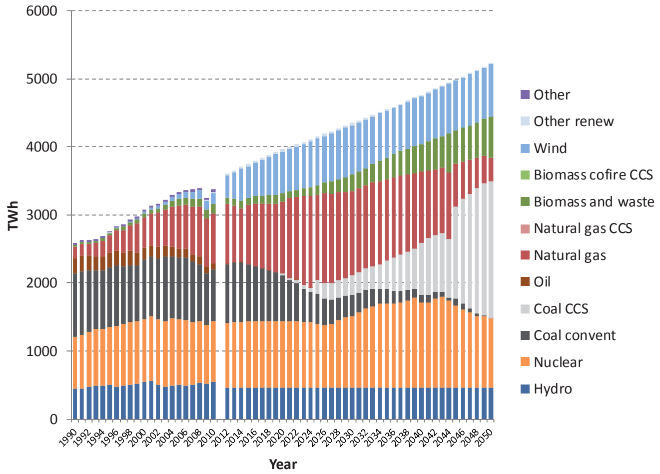


Figure 2.1: European (EU27+Norway and Switzerland) electricity generation in the Climate Market scenario

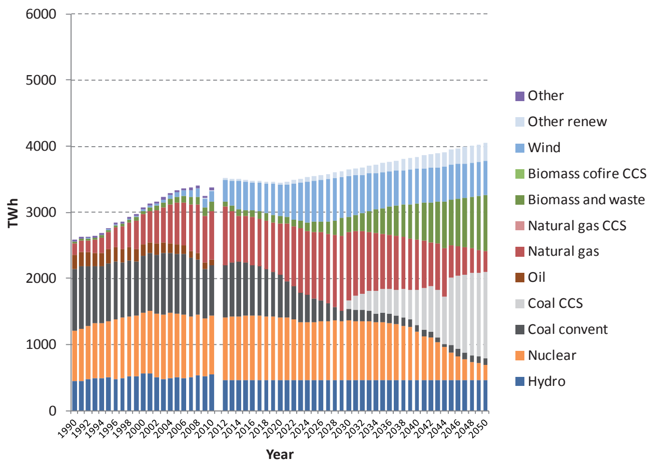


Figure 2.2: European (EU27+Norway and Switzerland) electricity generation in the Regional Policy scenario

2.3 Regional outlook

As mentioned earlier, the ELIN model covers all 27 EU Member States plus Norway and Switzerland. As a complement to the European perspective given in the previous section, a *regional* outlook is given in this section. For reasons of simplicity, the countries included in the model have been divided into four main European regions according to Figure 2.3 below. The long-term development of the electricity generation in

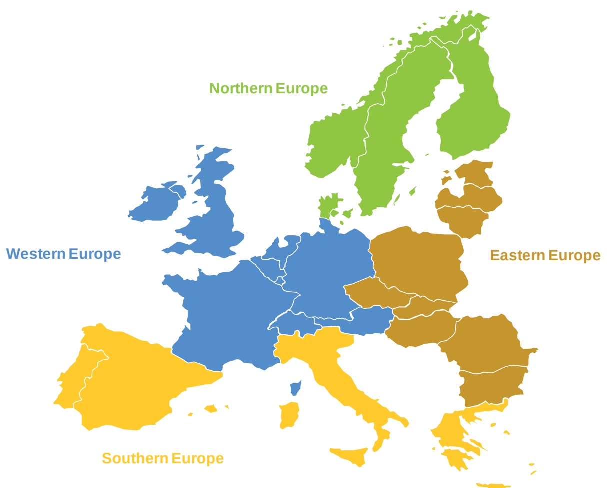


Figure 2.3: The four main European regions used in the present analysis

these four regions is summarized in Figure 2.4 and 2.5 below. The figure presents the relative distribution of renewables, nuclear and fossil within electricity generation today and in 2030 for the Policy and Climate Market scenarios.

It may be seen that the distribution of the different means of producing electricity vary substantially among the four regions (and, of course, among countries – also within a selected region). Northern Europe, as defined here, has the largest share of renewable also in the future, while fossil fuels are expected to continue to play a vital role in the other regions, especially in Southern and Eastern Europe. Furthermore, the larger electricity de-

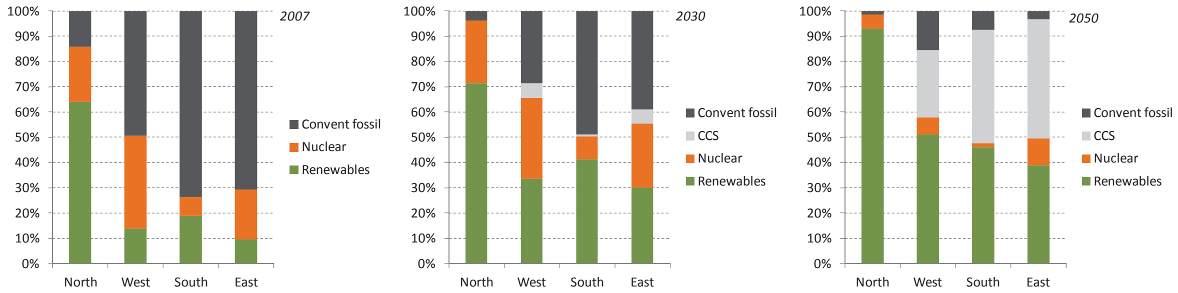


Figure 2.4: The distribution of renewable, nuclear and fossil electricity generation in the four chosen European regions in 2007, 2030 and 2050 (for the Regional Policy scenario)

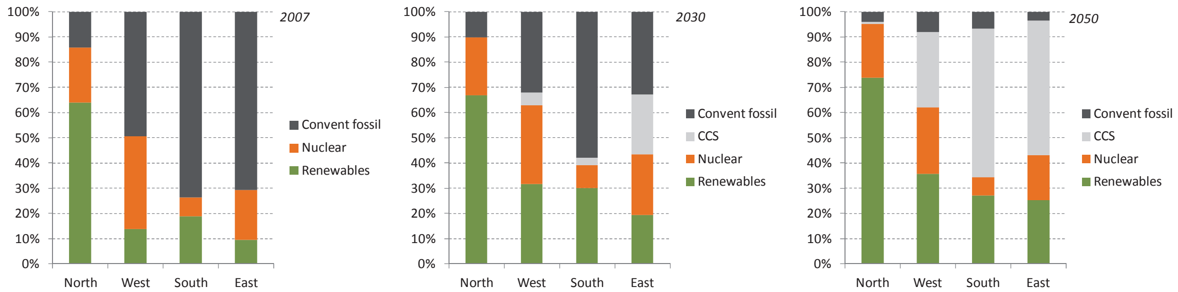


Figure 2.5: The distribution of renewable, nuclear and fossil electricity generation in the four chosen European regions in 2007, 2030 and 2050 (for the Climate Market scenario)

mand in the Climate Market scenario leads to a larger share of fossil fuels than in the Regional Policy scenario. A closer look at the development during the past 15 years (statistics taken from EUROSTAT) and the coming 40 years (based on ELIN model runs) in three of the four main regions of Europe is presented in Figures 2.6-2.8. (The development in the Nordic countries is presented in chapter 3 below, where a Nordic model has been used instead).

Western Europe

In Western Europe (cf. Figure 2.6) CCS plays an important role beyond 2025 in both the Policy and Climate Market scenarios. The share of renewables is around 25 percent by 2030 in both scenarios and 35 and 45 percent respectively by 2050. Conventional coal power declines steadily but is still remaining even towards the end of the period. In the Regional Policy scenario, (only planned investments are taken into account) when considering nuclear power. No further nuclear investments are assumed, implying that existing capacity is phased out due to ageing. In Germany the phase-out follows the governmental decision from 2011. In Germany the phase-out follows the governmental decision from 2011. In the Climate Market scenario, however, nuclear power may grow beyond planned investments in countries with existing nuclear capacity (and Poland where two new units are optional) but not exceeding the current relative share of total production. As in the Regional Policy scenario, nuclear power is phased out in Germany but at a reduced pace, implying that the last nuclear unit is closed in 2030.

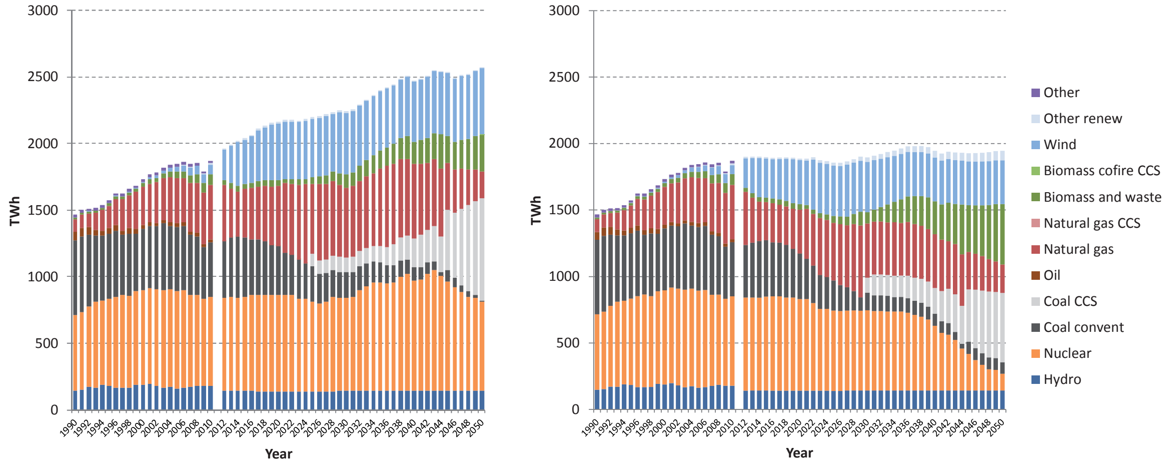


Figure 2.6: Long-term development of the electricity-generation system in Western Europe (Germany, Austria, Switzerland, UK, Ireland, Luxembourg, France, Belgium and the Netherlands) under Climate Market scenario (left) and Regional Policy scenario (right) assumptions

Southern Europe

In Southern Europe (cf. Figure 2.7), model results indicate that gas power is the most important player in the short-to-mid term. A considerable share of this is already decided or planned facilities. However, in the long run due to increased gas prices and high costs for gas CCS, coal CCS becomes the dominant contributor towards the end of the model period. The relatively low penetration of nuclear power is mainly explained by the low share today. Even though e.g. Italy today considers nuclear power as an option in the future it has not been included in the model (even in the Climate Market scenario the option of investing in new nuclear capacity is generally restricted to countries that today are in possession of nuclear power).

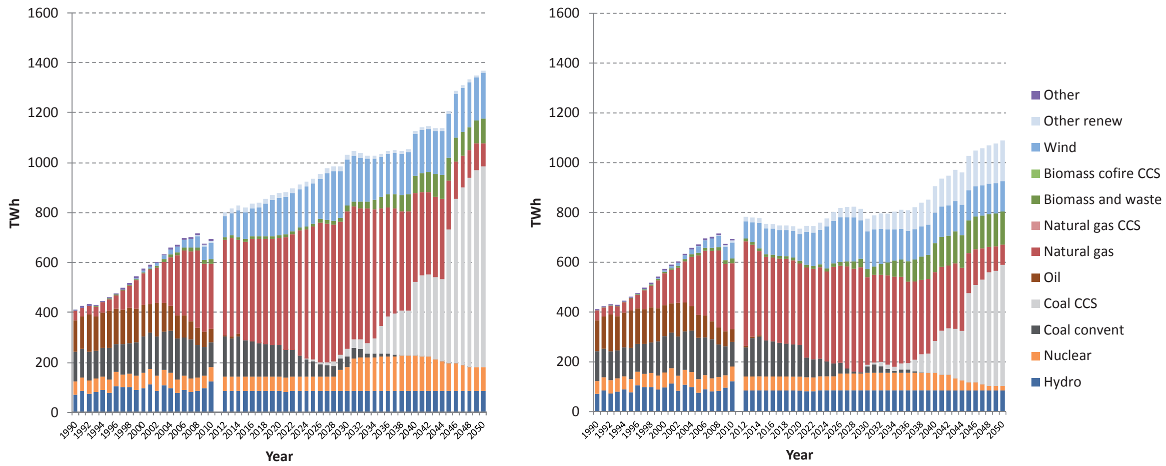


Figure 2.7: Long-term development of the electricity-generation system in Western Europe (Germany, Austria, UK, Ireland, Luxembourg, France, Belgium and the Netherlands) under Climate Market scenario (left) and Regional Policy scenario (right) assumptions

Eastern Europe

In many Eastern European countries (cf Figure 2.8) the short and mid-term need for new investments is substantial since many power plants are of old age. Therefore, significant changes in power supply are likely to be imminent in this region. This is indicated in Figure 2.8 by a rather pronounced initial decrease in coal power accompanied by a corresponding ramp-up of the use of gas power (the model takes only limited consideration to the possible pace of building new power plants).

Contrary to the other regions, it is assumed here that electricity-demand growth is significant in this region in both the Policy and Climate Market scenarios. Finally, the amount of biomass-based power (CHP, cofiring and some condensing power plants) amount to a substantial share towards the end of the period – significantly larger in relative terms than in any other region. Assumptions on abundant (and relatively cheap) biomass resources, explain this.

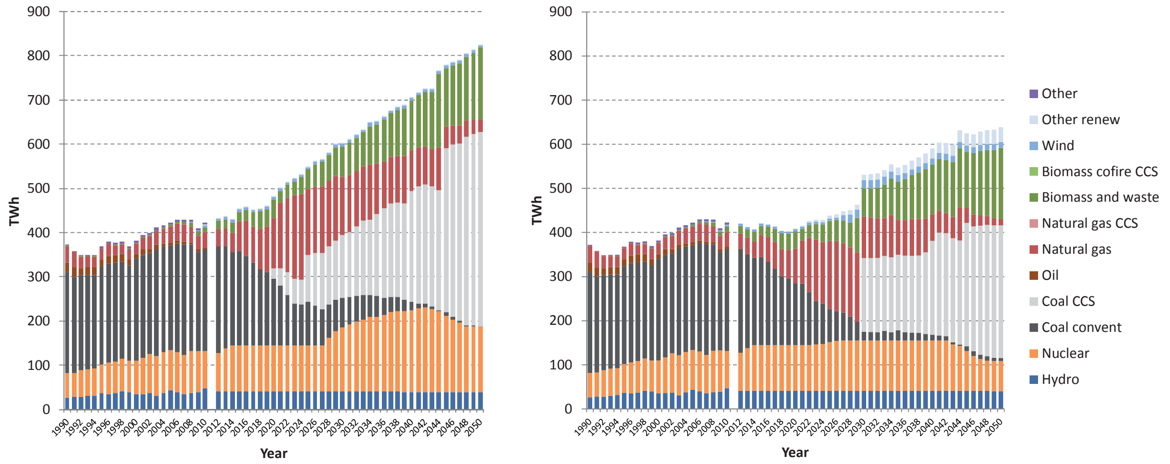


Figure 2.8: Long-term development of the electricity-generation system in Eastern Europe (the Baltic States, Bulgaria, Czech Republic, Slovakia, Hungary, Poland and Romania) under Climate Market scenario (left) and Regional Policy scenario (right) assumptions

2.4 Concluding remarks

It may be concluded from the analyses that far-reaching climate-policy targets can be fulfilled with, to a large extent, relatively conventional technology. Even though the share of renewables steadily increases over time in the model runs, a very large contribution still originates from fossil fuels in the future. The key to this is the assumed availability and commercialisation of CCS technology. This is, of course, a very important precondition. If, for some reason, CCS will not become commercialized during the coming decades, the development of the European electricity-generation system will be significantly different from what has been shown here, given ambitious climate targets. This is, among other things, dealt with in some of the other scenarios and sensitivity analyses that will be reported in more detail later in the project.

Future demand for biomass is, in some cases, of substantial size. Even though it may be achievable from a supply-side point of view such as development will undoubtedly imply major logistic and infra-structural challenges. Such infra-structural challenges also apply to e.g. CCS, which plays a decisive role in several of the scenarios dealt with during the NEPP project. Large infra-structural investments are likely to partly act as "inhibitors" meaning that no single option will entirely dominate future supply. A mixed balance including many technological options and resources is, therefore, desirable not only from a security-of-supply perspective, but also due to the fact that a very large single share of each and one of the key technologies identified here (CCS, biomass, wind power etc) requires enormous investments in infra structure.

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2.5 Reliable long-term planning of electricity transmission

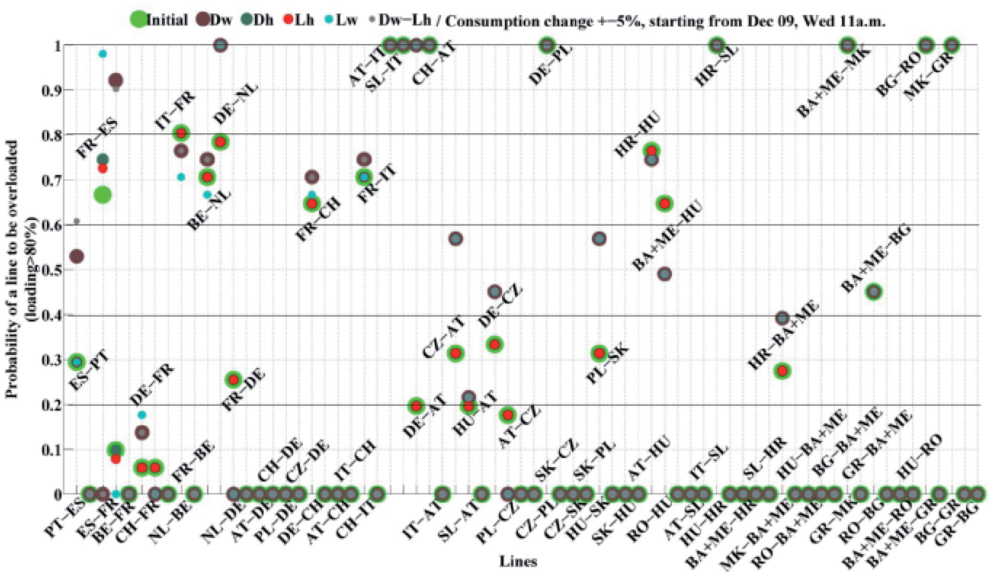
Previously it has been shown that the need for new investments in electricity transmission is of considerable size in the entire EU. This is, among other things, related to the fast expansion of renewable electricity generation. In order to get a clear and full picture of the impact of transmission-grid investments on the entire electricity system, decisions and planning related to transmission investments need to consider many aspects: security of supply, environmental policy, the development of electricity generation and electricity-market structures.

Key transmission investments include electricity interconnectors between the different Member States of the EU. This section focuses on the impact of interconnection failures at critical areas on unserved energy in the European system, performing a sensitivity analysis. Six generation mix scenarios have been considered combined with randomly chosen load variations on every node, in order to calculate congestion probabilities of lines and probabilities of unserved energy on the nodes

The decision maker has to consider many different aspects during the definition of transmission planning strategy, that sometimes might be contradicting. In the whole planning framework the decision is made by combining economic, environmental, and security of supply criteria in a single pseudodynamic algorithm. Here the part of security of supply is analyzed. After a sensitivity analysis for identification of critical/important transmission lines, a contingency analysis is performed and the probability of expected unserved energy is calculated together with the costs of expected unserved energy as an indicator. It is also shown that the amount of expected unserved energy is decreasing when additional transmission capacity is added to the connected lines of an unbalanced node. However, this may not be enough to reach zero unserved energy due to limitations of other transmission lines. After all, transmission network reinforcements can be evaluated based on benefits in avoided environmental costs, avoided congestion costs and avoided unserved energy costs in order to provide sufficient information to the decision maker.

System characterisation & identification of critical paths

A sensitivity analysis is used in order to identify the critical paths or geographical regions in the network. The sensitivity analysis is based on scenarios for variable load of ± 5% for the 20 countries included in the model (described below). The load condition of winter peak load of the 3rd Wednesday, January 2009 is taken as starting point. Besides the demand variation, different generation conditions are also taken into account. Therefore, an amount of 306 cases is generated in order to calculate the probability of overloading on the interconnections.



COUNTRIES ABBREVIATIONS

PT - Portugal
ES - Spain
FR - France
BE - Belgium
NL - Netherlands
DE - Germany
CH- Switzerland
IT - Italy
AT - Austria
CZ - Czech Republic
PL - Poland
SK - Slovakia
HU - Hungary
SL - Slovenia
HR - Croatia
BA+ME - Bosnia + Serbia
MK - F.Y.R.O.M.
BG - Bulgaria
RO - Romania
GR - Greece

Fig. 2.9: Probability of lines to be loaded over 80%

Overloading here means loading more than 80% of the total net transfer capacity of a line. The results of overloading probability are presented in Fig. 2.9.

The different generation conditions that have been studied are the following all with the
1. Base case Ititial set-up of 3rd Wed. 19:00pm Jan.2009 (initial).
2. Dry year, half hydro power availability for CH, AT, ES, (low hydro, lh).
3. Low wind, half wind power availability for DE, ES, NL, IT, (low wind, lw).
4. Double wind, double wind power availability for DE, ES, NL, IT, (double wind, dw).
5. Double hydro power availability for CH, AT, ES, (double hydro, dh).
6. Double wind and low hydro power availability for the previous mentioned countries, (Double wind-low hydro, dw-lh).

From the sensitivity analysis derives that some lines are permanently congested, no matter what the load level or the generation set-up is. These lines are between AT-IT, SL-IT, CH-AT, HR-SL, BG-RO and MK-GR. Other lines are more sensitive to load or generation changes, however still with a high probability of loading over 80%. The reliable available capacity when the unavailable capacity and the reserved capacity for system services are subtracted is also analyzed. This margin represents the maximum capacity that can be used at a certain moment in order to cover the demand without consideration of any imports-exports. It is obvious that for the initial set-up of the system the nodes are able to operate under isolated conditions neglecting any demand growth. Nevertheless, in case of interconnection outage for any reason, and simultaneous demand growth or different generation availability, some of the nodes are going to remain unbalanced and a certain amount of demand is considered as unserved.

Contingency analysis

For the contingency analysis, the unserved energy probability of a node is calculated, when only one interconnection is on outage. As the interconnections represent aggregated transfer capacities, two cases for reduced transfer capability have been considered. One for 100% and one for 50% of the whole transmission capacity. This means that most probably only 1 or 2 lines are out of order. For failures less than 50% all nodes are able to cover their own load, while with increasing failure level the effects are closer to the results analyzed in this work. Each time an interconnection fails a sensitivity analysis for the aforementioned generation scenarios is performed. This time the demand varies randomly on a normal distribution picking up 100 samples for each node. Using this controlled randomize selection of demand an average increase of 5-6% of the total system load is achieved. Only the following lines are considered in this contingency analysis: AT-IT, SL-IT, CH-AT, CH - IT, FR - IT, DE - PL, ES - FR and MK-GR. Besides the observation that Italy might be unbalanced with a probability of 5% when the line SL -IT fails and with 28% when the line AT -IT fails, there are two other important results. The first refers to the failure between Spain and France. When this capacity is unavailable the nodes of Portugal and Spain remain unserved with the same probability of 25% and also Belgium with a very low percentage. This is explained from the high cheap production capacity of France that acts as an important exporter. When this line is trips an island of Spain and Portugal is created that cannot cover its own demand with a quite high probability. The second interesting result refers to the line failure between Switzerland and Italy. In this case Italy is able to cover the local load, however Slovenia is weakly interconnected to the neighbors and cannot import the needed power, as well as Croatia. The remaining available capacity on these nodes are also not enough and thus Slovenia and Croatia remain unbalanced with a probability of 10% and 5% respectively.

The unserved energy costs

In order to calculate the total unserved energy costs, it’s important to know how much is the unserved energy and how much does a MWh of unserved energy cost. In different studies, different numbers for estimated unserved energy costs appear distributed in residential industrial and mixed residential areas. The unserved energy price turns to be very high compared to the marginal production prices, due to many influenced parties and negative effects. For this case study a cost of 3000€/MWh has been assumed, which seems to be an optimistic estimation.

Network reinforcements may be from different aspects beneficial for the society and for the network itself. From the amount of calculated costs of unserved energy can be stated that the reduction of unserved energy is as an important indicator as the benefits from environmental costs reduction or congestion costs reduction.

Network reinforcements

In this section an example of network reinforcement and its impact on unserved energy is examined. As an example here it is used the contingency scenario of the line between Italy and Austria, as it leads to the highest probability of unserved energy for Italy. A reinforcement is assumed to be made on the line between Switzerland and Italy with an initial capacity of 3890 MW. The line capacity is then increased by 10% for several steps until a low amount of unserved energy is reached. The model result shows the relation between the amount of unserved energy and the additional transmission capacity. From the picture derives that the amount of reduction of unserved energy is not linearly dependent from the additional capacity of the line, which means the amount of reduced unserved energy is not equal to the amount of increased capacity of the line. It is additionally shown that no matter how big the transmission capacity of this line is, it is not enough to lead to zero unserved energy, due to transmission limitations of the neighboring lines. This observation could initiate combined reinforcements in meshed interconnected systems involving many control areas and TSOs.

The previously calculated amount of reduced unserved energy due to new available capacity at an interconnector could be used in the cost-benefit analysis as an additional benefit. Of course, the problem remains a problem of contradicting interests as the lowest amount of unserved energy refers to the highest transmission lines capacity, however the more the transmission capacity the higher the investment costs. Combining environmental, congestion and unserved energy benefits a wide scope of the impact of the transmission investment is provided that facilitates the final investment decision.

Model development

In previous work the generation and transmission models have been combined in a cost-benefit analysis in order to evaluate potential transmission expansion plans in the European interconnected system. Avoided environmental costs (AEC) and avoided congestion costs (ACC) due to additional transmission capacity had been compared to transmission lines investment costs. However, in this work a detailed description of the identification of proposed candidate lines, together with an indicator for system reliability analysis was missing. Furthermore in the system adequacy studies of ENTSO-E, the capacity exchanges between countries is considered as infinite, which is not so realistic. This work contributes in the characterization of the European electricity network and its long-term reliability analysis considering transmission capacity limits and voltage angle limits. After the identification of critical interconnected lines the probability of unserved energy on each node, if any, is calculated for cases with and without transmission network reinforcement. The whole study is based on an aggregated copper-plate model of EU-20, that was developed in order to perform economic studies in the system of continental Europe.

Model description

An aggregated European model has been created appropriate for transmission network planning studies and examination of how the generation mix change interacts with it. Thus, not only investments in new generation technologies but also the constraints of the transmission network could be considered in the system. For the development of the model only publicly available data from ENTSO-E and former UCTE have been used.

The model consists of 20 nodes, that represent 20 countries of western and southeastern Europe. Each node is connected to another, only if an interconnection is existing. On every node 5 different production technologies are assigned, e.g. nuclear, hydro, gas, coal and renewables. Generation capacities are aggregated for the whole country according to the maximal installed capacity reported from UCTE in 2008. The same for the load levels and the interconnection capacities, that where assumed to be equal to the net transfer capacities (NTC as aggregated transfer capabilities. Other line characteristics, e.g. line reactance, were based on typical values and on an impedance calculator provided by Powerworld software in which the model is implemented.

The optimization is based on DC-OPF for nodal price calculation, subject to nodal equality constraints, generation capability limits, transmission capacity limits and voltage angle limits. The reliability indicator used here is the unserved energy when an outage of an interconnection or group of interconnections occurs. The modelling approach of unserved energy is described below. In order to avoid convergence problems, the unserved energy has been modelled as an additional in-feed source on each node with a very high cost assigned to it. Thus, it is a kind of emergency capacity that is used when the node is not able to cover it is own demand in case of outage.

A cost-benefit analysis is used in this study which considers environmental, economic and technical benefits. The analysis helps along with the selection of a reinforcement in the transmission network. The benefits from a proposed transmission project consist of a societal, a market based and a reliability element. The first element is assigned to less CO_2 emissions due to less utilization of conventional power plants, the second to the reduction of congestion costs and the third one to the reduction of unserved energy on some nodes of the network when an incident occurs.

References

[1.] Papaemmanouil, L. A. Tuan, G. Andersson, L. Bertling, F. Johnsson, A cost-benefit analysis of transmission network reinforcement driven by generation capacity expansion, IEEE PES General Meeting, 2010.

[2.] A. Papaemmanouil; L. Bertling, T. Le; G. Andersson,: Improved cost-benefit analysis for reliable long-term transmission planning. 2011 IEEE PES Trondheim PowerTech: June 2011, ISBN/ISSN: 978-142448419-5.

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3. Nordic energy system scenarios

3.1 Introduction

In this section the preliminary model results for the four NEPP main scenarios are presented. The analyses have so far been focused on supply of electricity, where input parameters are combined in a manner that results i fundamentally different development of electricity generation between the scenarios. This may be related to assumptions regarding technical development (e.g. CCS), energy policy (e.g. new nuclear power) or the magnitude of subsidy systems (e.g. for renewable energy). Corresponding influence on electricity demand for electricity has so far not been analysed in detail. The development of electricity demand is so far only based on simplified assessments. Demand will be analysed in more detail later in the project.

The presentation is focused on Nordic and Swedish results.

3.2 Electricity generation in the different scenarios

Reference scenario

We begin by showing the results for the Reference scenario. This case is characterized by the present set of policy instruments. Fossil-fuel prices are chosen according to the WEO 2011 "Current policy" scenario. Furthermore, two additional nuclear power reactors are optional in Finland as well as in Poland. In Sweden, total existing nuclear capacity (after ongoing capacity increases) may be maintained through investments in new units. In Germany, nuclear power is phased out according to the governmental decision of 2011. In this scenario, electricity demand may be briefly summarized as stagnating or slowly increasing. Climate policy is characterized by continued bur moderate ambitions. This corresponds to an EUA price of 18 EUR/t in 2020 and 35 EUR/t in 2050.

SWEDEN

The figure below presents the development of Swedish electricity generation up to the year 2050 for the Reference case. The real generation mix for a selection of the twenty last years is also shown.

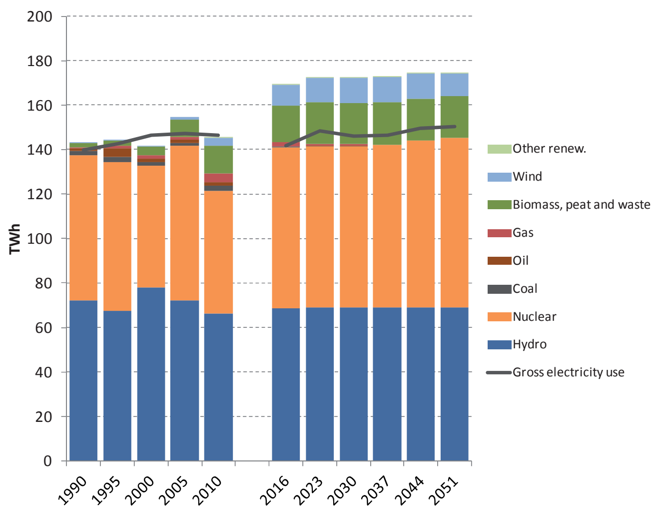


Figure 3.1: Swedish electricity generation, Reference scenario

The increased capacity of nuclear power plants, together with normalized availability lead to more than 70 TWh/year nuclear electricity. (In the model it is allowed to build new reactors when the existing plants are closed due to live length limitations.) This leads to a typical total yearly electricity generation in Sweden of 170 TWh/year.

The existing Swedish-Norwegian electricity certificate system results in an increase in renewable electricity until 2020. After this the policy instrument does not give incentives for further expansion and no more renewables are added in Sweden. The Swedish surplus of electricity and the market price of electricity do not give incentives for further expansion of renewables, without additional support.

The stagnating electricity demand, in combination with increased generation leads to a net electricity surplus in the range of 25 TWh/year.

THE NORDIC REGION

Some of the trends observed for Sweden are also seen at the Nordic level. One difference however, is that the Nordic electricity demand grows somewhat, whereas the Swedish demand is more or less constant. This influences the exchange of electricity with neighbouring countries. The figure below presents the development of Nordic electricity generation up to the year 2050 for the Reference case.

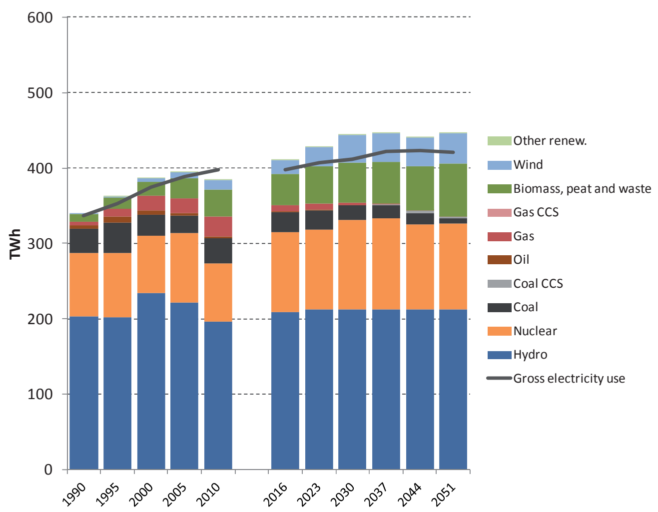


Figure 3.2: Nordic electricity generation, Reference scenario

The Nordic electricity generation is characterized by a large share of hydro power. The remaining part is in the long term shared between other renewables and nuclear power. Increased capacity in nuclear power plants combined with better availability in Sweden, together with two new nuclear reactors in Finland (six in total) results in a yearly nuclear electricity production of 120 TWh.

Renewable electricity expands and makes up 70 % of the total production. Hydro power is the largest source, but the possible expansion is very limited. Wind power and bio CHP however grows significantly. Although the total electricity generation increases, renewables manage to increase its market share slightly.

The net export is typically 20 – 30 TWh/year. This is approximately the same export as shown for Sweden. This means that Denmark, Norway and Finland together are neither exporting nor importing. Sweden is thus the main source of Nordic net export of electricity.

Regional policy scenario

The next scenario is the Regional policy case. This scenario is characterized by detailed policy steering[1]. Examples of such policies are efficiency policy instruments, resulting in decreasing electricity demand in Sweden and constant in the Nordic region. Another feature is a renewable energy target identical to the Reference scenario up to 2020, and thereafter increasing further. In the regional policy scenario this general target is supplemented but specific targets for a number of renewable electricity producing alternatives. Nuclear is treated as in the Reference scenario. (German nuclear power is phased out.) Fossil-fuel prices are chosen according to the WEO 2011 "New policy" scenario. The European climate-policy target corresponds to a EUA price development of 30 EUR/t in 2020 and 55 EUR/t in 2050.

SWEDEN

The figure below presents the development of Swedish electricity generation up to the year 2050 for the Regional policy scenario. It shows large differences compared to the Reference scenario.

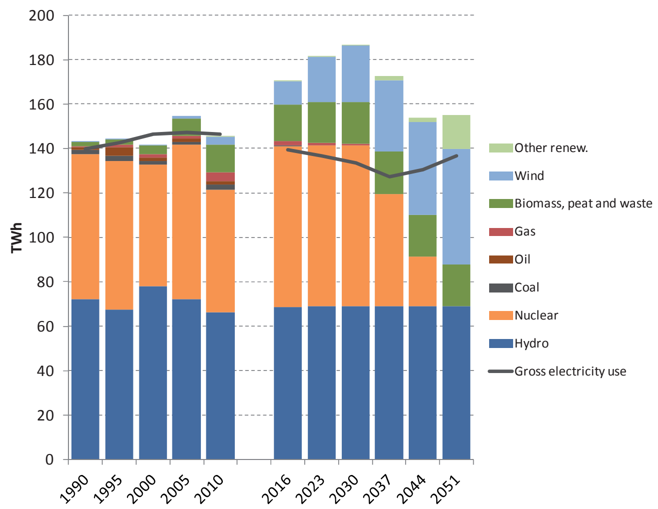


Figure 3.3: Swedish electricity generation, Regional policy scenario

Nuclear power increases in the short term (up to 2030) due to better availability and capacity increases. However, in this scenario no new nuclear power is built when existing plants are closed for life length reasons. This can be explained by the relatively moderate wholesale electricity prices as a result from the dramatic expansion of renewables, above all wind power, in combination with stagnating or even decreasing electricity demand. It is simply not economically feasible to invest further in nuclear power in Sweden in this scenario.

Due to policies for specific renewable electricity generation the scenario results in a large expansion of wind power, reaching 30 TWh 2030 and 50 TWh by 2050. (Here we have used the largest part of the wind power potential allowed in the model.) Other renewables also increase after 2030, mainly solar power, but also wave power.

Due to the combination of decreasing electricity demand and increasing renewable generation Sweden shows a large net export of electricity, approximately 50 TWh/year for the first half of the studied period. After this the export decreases due to the phasing-out of nuclear power. In spite of the fact that 70 TWh of nuclear power disappears, Sweden remains a net exporter of electricity. This is an indication of the size of the expansion of renewable generation. The decreasing/stagnating demand is, as mentioned, another explanation for the long term export.

[1] The term "regional" refers to the view that significant regional differences with respect to policy goals and means continue to exist. This is particularly true for the climate target where it is assumed that EU moves forward with high ambitions without a corresponding effort from the rest of the world.

THE NORDIC REGION

The differences between the Reference and Regioanl Policy scenarios are not as obvious at the Nordic level, but the trends seen for Sweden exist also for the Nordic region. The figure below presents the development of Nordic electricity generation up to the year 2050 for the Regional policy scenario.

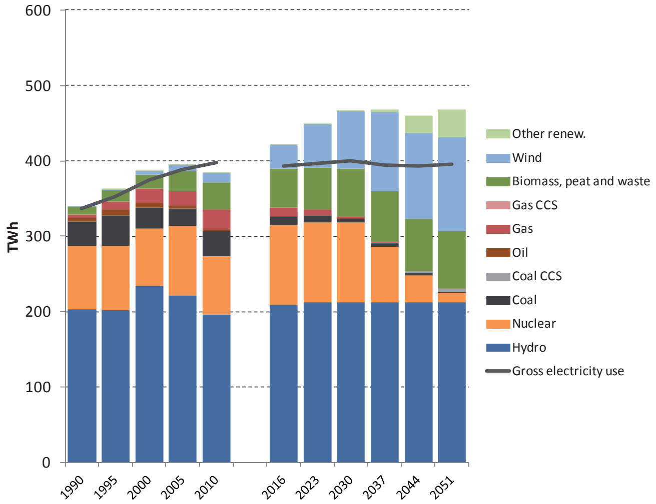


Figure 3.4: Nordic electricity generation, Regional policy scenario

No nuclear power is built, neither in Sweden nor in Finland (apart from the fifth Finnish reactor which generates electricity during the whole model period). The reason is, as for Sweden, that the model does not find it profitable to invest in nuclear power. This is due to large expansion of other, renewable, generation in combination with stagnating electricity demand.

Renewable generation increases considerably and covers 85 % of Nordic electricity generation by the year 2035. This share increases even further after this, as a result of the on-going phasing-out of nuclear power.

The Nordic net export of electricity grows to 50 – 70 TWh/year after 2020. This is explained partly by increased renewable generation and partly by efficiency and savings efforts in the demand side use of electricity. The increased use of renewables is achieved by means of a joint European support system for renewable electricity generation with support levels of approximately 300 – 400 SEK/MWh. It is remarkable that such a large net export of electricity is achieved in spite of the phasing-out of nuclear power.

THE ROLE OF NUCLEAR POWER IN THE REGIONAL POLICY SCENARIO

In a sensitivity analysis we have studied the role of nuclear power in the Nordic electricity generation system. In the scenario presented above nuclear power is phased out when the plants have been in operation for 60 years, which is the assumed life length of the power plants. If we instead assume that all nuclear power plants have a remaining life of more than 40 years, all existing nuclear power plants will be available during the whole analysis period. This will result in lower electricity prices, and as a consequence larger electricity demand and slower growth in renewable electricity generation. The latter is explained by the lower system price of electricity in combination with unchanged European support for renewable electricity generation. This leads to a lower total income for renewable electricity production. The figure below presents the development of Nordic electricity generation up to the year 2050 for the Regional policy scenario, however assuming longer life for existing nuclear plants.

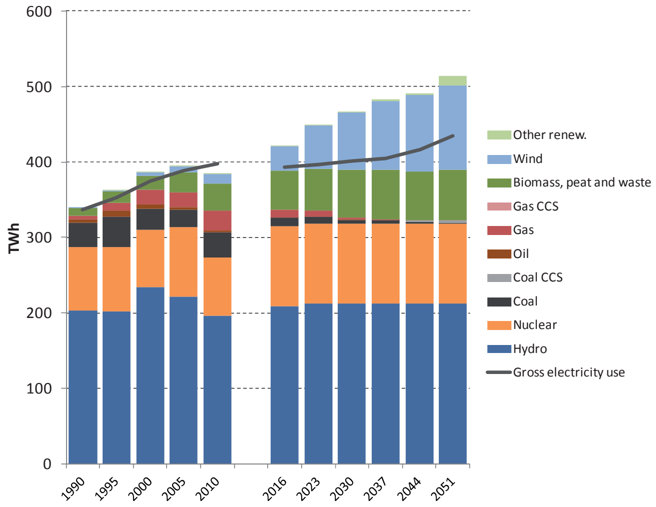


Figure 3.5: Nordic electricity generation, Regional policy scenario

Climate market scenario

The Climate market scenario reaches approximately the same climate targets for 2050 as the Regional policy scenario. In the Climate market scenario however, the dominating policy instrument is an emission trading scheme, "the CO_2-price". There are no specific renewable energy targets after 2020 and, compared to the Regional policy scenario, less efforts to reduce electricity demand through efficiency measures and savings. Electricity demand is not only higher than in the Regional policy scenario but also higher than in the Reference scenario. Electricity can here be seen as an important tool for limiting the CO_2-emissions. Therefore, the European emission-allowance price is assumed to be significantly higher in this scenario than in the previous scenarios, namely 30 EUR/t in 2020 and 150 EUR/t in 2050. Fossil-fuel prices are, however, the same as in the Regional Policy scenario.

SWEDEN

The figure below presents the development of Swedish electricity generation up to the year 2050 for the Climate market scenario. It shows large differences compared to the Regional policy scenario, but large similarities with the Reference scenario, at least in the short term.

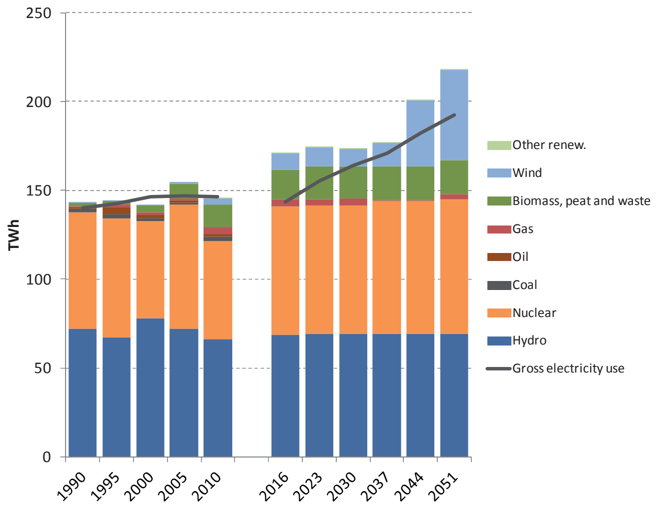


Figure 3.6: Swedish electricity generation, Climate market scenario

Since less renewable electricity generation capacity is "pushed into the system" this scenario results in higher electricity prices than in the Regional policy scenario. This makes it profitable to build new nuclear power, resulting in a yearly production of 70 TWh (as in the Reference scenario).

The development of renewable electricity generation is similar to the Reference scenario up to 2030. After this the higher electricity price of the Climate market scenario leads to considerably larger contributions from renewables. The higher electricity price is related to larger electricity demand and higher CO_2-price.

Here the net electricity export is in the range of 10 – 20 TWh/year. This could be compared to 25 TWh/year in the Reference scenario. This means that larger increase in electricity demand off-sets the increased renewable electricity generation.

THE NORDIC REGION

The same trends as described for Sweden can also be found at the Nordic level. The figure below presents the development of Nordic electricity generation up to the year 2050 for the Climate market scenario.

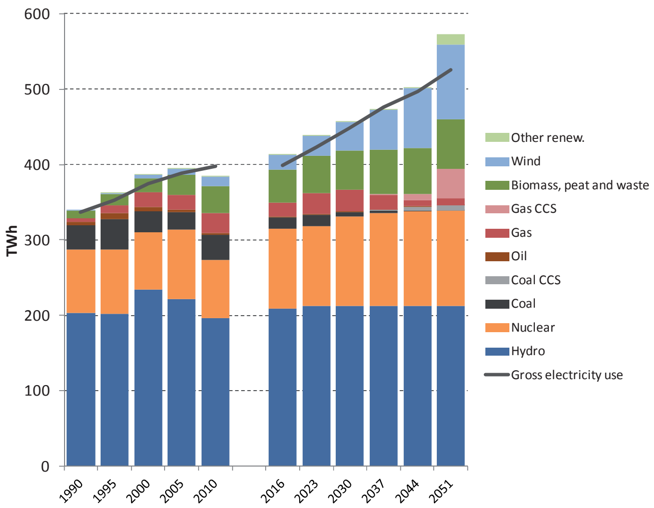


Figure 3.7: Nordic electricity generation, Climate market scenario

Nuclear power develops as in the Reference scenario also at the Nordic level. The high electricity price leads to expansion of renewable electricity generation, but its market share stops at 70 %, since nuclear power remains a large non-renewable generation resource. The high electricity price is not high enough to motivate renewable electricity generation at the Regional policy scenario level, which is reached through additional policy instruments aimed at renewables.

Natural gas based generation grows due to comparatively low gas prices and lack of specific support to renewables. The last periods these gas fired plants will be equipped with CCS due to high CO_2-price.

The rapid increase in electricity demand results in a situation where the Nordic region is in balance between generation and demand. Net export is seen only at the very end of the studied period. Electricity generation based on fossil fuels in combination with CCS is competitive in Germany and Poland due to economy of scale. There is no point in placing such power plants in the Nordic region for export since we have no competitive advantages for such plants.

Green policy scenario

The Green policy scenario is characterized by a very high share of renewables. The main driving force for this is a very high renewable electricity target, supported by a European policy instrument resulting in a support of 500 SEK/MWh (without any differentiation between different types of renewables). All European nuclear power is also phased out, i.e. no new plants are built to replace old plants that are closed due to reached life length. Another reason for the very high share of renewables is that this scenario assumes that CCS will not be an option to facilitate the use of fossil fuels with drastically reduced CO_2-emissions. The reason for not using CCS could for example be political, technological or public acceptance related.

SWEDEN

The figure below presents the development of Swedish electricity generation up to the year 2050 for the Climate market scenario. The results are similar to those presented for the Regional policy scenario.

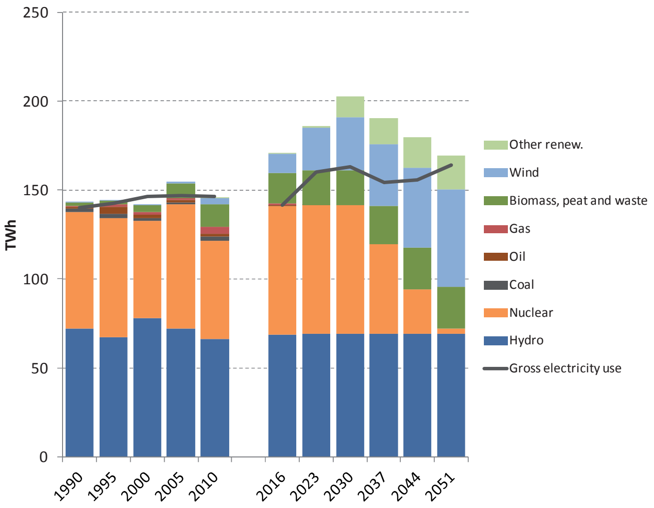


Figure 3.8: Swedish electricity generation, Green policy scenario

As mentioned above this scenario shows more or less the same development for electricity generation. The described potentials for renewable electricity is virtually used to the last MWh. One difference is however, the electricity demand. One reason for this is the efficiency and savings efforts assumed in the Regional policy scenario, which are not as ambitious in the Green policy scenario. Another reason is that the support systems for renewable electricity are even more generous in the Green policy scenario, resulting in lower electricity prices. These lower prices stimulate the use of electricity, leading to higher electricity demand than in the Regional policy scenario.

The larger electricity demand, combined with virtually the same electricity generation development leads to lower net electricity export from Sweden. In spite of the full nuclear phase-out it is still interesting to note that Sweden remains a net exporter of electricity, or at least in balance, as a result of the dramatic expansion of renewable electricity generation.

THE NORDIC REGION

The same trends as described for Sweden can also be found at the Nordic level. For Sweden we found large similarities with the Regional policy scenario. This is true also for the Nordic region, but here the reshaping of the electricity generation system is even more dramatic. The figure below presents the development of Nordic electricity generation up to the year 2050 for the Climate market scenario.

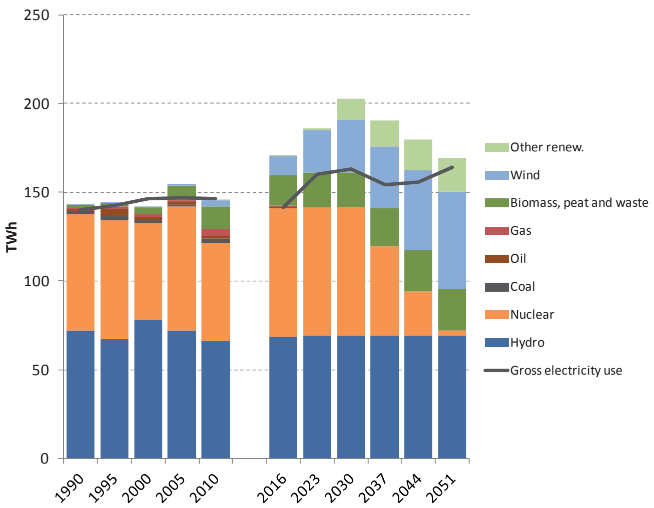


Figure 3.9: Nordic electricity generation, Green policy scenario

In this scenario more or less the full renewable potential is utilized. This results in an increase in renewable electricity generation of 200 TWh to 2050! The Nordic region will therefore act as a major net exporter of electricity despite phasing-out most of the nuclear power during the studied period. (Only the fifth Finnish reactor is still in operation in 2050.) The net export amounts to approximately 70 TWh/year after 2020. This is even more notable since the Nordic electricity demand is comparatively high in this scenario. The reason for the high electricity demand is, as described for Sweden, low prices, as a consequence of very strong support system for renewables, and moderate efficiency and savings targets.

3.3 A few words about capacity

Especially two of the studied scenarios show a development of the electricity generation mix that raises questions. It is above all the Regional policy and Green policy scenarios that are characterized by a decrease in thermal production in favour of variable, and partly intermittent, renewable generation. Examples of such variable renewable generation are wind power, solar power and wave power. These generation sources have a certain lack of predictability and reduced capacity value (relatively low predictable availability when capacity is needed most, e.g. during cold winter days) in common. In the Green policy scenario such generation amounts to 55 % of the total Nordic generation in 2050. This forms certain challenges for the electricity system that is discussed in greater detail in other parts of the NEPP project. The installed capacity for the scenarios Regional policy and Green policy are shown in the figure below.

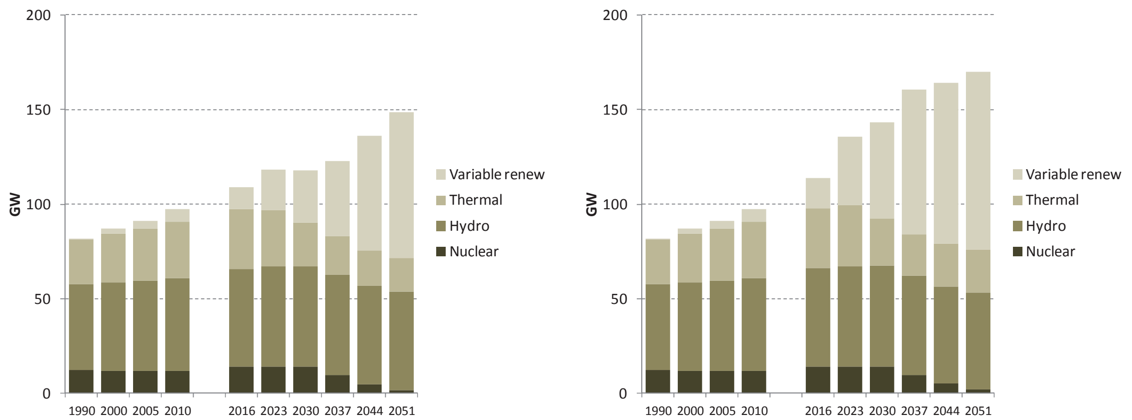


Figure 3.10: Capacity development in the Nordic region (Regional policy scenario to the left, Green policy scenario to the right)

Although the installed capacity increases significantly in both scenarios, the generation resources with high capacity value are shrinking. Moreover, the remaining thermal power changes over time from condensing plants to CHP plants. This is a disadvantage since the electricity generation therefore is linked to the heat demand. However, this disadvantage is small since the maximum demand for electricity often coincides with maximum electricity demand. Furthermore, these CHP plants can often operate in condensing mode, which reduces this disadvantage even more.

The comparatively large share of hydro power is very valuable in this situation. This power generation is capable of balancing this system in a favourable way. The large, rather rapid swings in generation from e.g. wind will however, result in large price differences on the North European electricity market.

The structure of the electricity generation system is problematic from a capacity point of view, especially since we foresee a similar development in the rest of Europe. The speculation among experts is that market prices on an "energy only market" will not be sufficient to give incentives to build the necessary reserve capacity. This could create a situation with reduced delivery security and/or extreme price volatility. One solution to this is to establish a capacity market. This is happening in some European countries. Such a market creates incentives for building and operating plants also with limited operating hours. This is discussed further in the section about different market scenarios.

3.4 Electricity trade between countries and regions

The electricity trade has been discussed in the sections above for each specific scenario. Here we chose to focus on the differences and similarities in electricity trade between the scenarios. The net electricity export for Sweden and for the Nordic region is shown in the following figure.

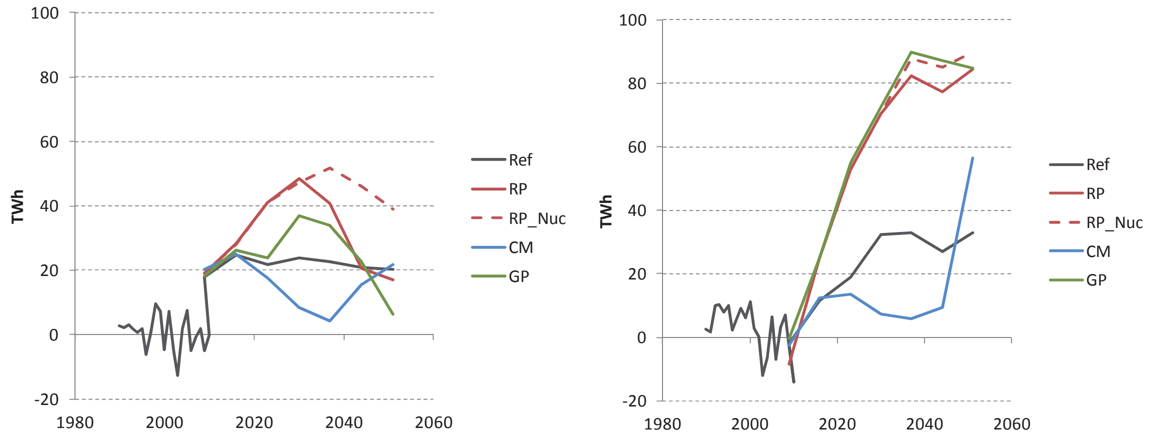


Figure 3.11: Net electricity export in the four scenarios (Sweden to the left and the Nordic region to the right); Nordic figures include a net import from Russia

In all scenarios Sweden and the Nordic region act as net exporters of electricity. At the Nordic level it is interesting to note that the largest net export coincides with the scenarios that assume a phasing-out of nuclear power! The effect of large efforts to expand renewable generation and/or reducing electricity demand is thus more important than the effect of continued use of nuclear power. The scenarios with nuclear phase-out both include strong support systems for renewable electricity generation, and the effect of these policy instruments create more electricity generation than is lost through nuclear phase-out. However, sensitivity runs related to the Regional Policy scenario indicate that for a given scenario, a nuclear phase-out reduces the Nordic electricity export, all else constant.

The scenarios where nuclear power is kept constant at a high level, results in lower net electricity export for different reasons. The Reference scenario is characterized by low electricity demand and a lack of long term support for renewable electricity. The Climate market scenario combines high domestic Nordic electricity demand and moderate expansion of renewables. For different reasons this means that the scenarios with constant nuclear power, surprisingly, stand out as the scenarios with smallest net electricity export. A combination of constant nuclear power and ,strong support for renewable electricity generation and reduced electricity demand would facilitate a very large export. This is indicated in the sensitivity analysis related to the Regional policy scenario.

As shown in the “historic section” of the figures above we have experienced large swings between export and import. The reason for this is different combination of hydrological conditions, temperature, and macro-economic conditions. In the calculations of future export/import we assume average values for such parameters. This means that additional variations, related to such variables, will in reality be superimposed on the shown development.

In the four figures below we present the exchange of electricity in more detail between countries and regions for two of the scenarios; Climate policy and Green policy. These figures show that the electricity exchange is larger than indicated in the “net export figures”.

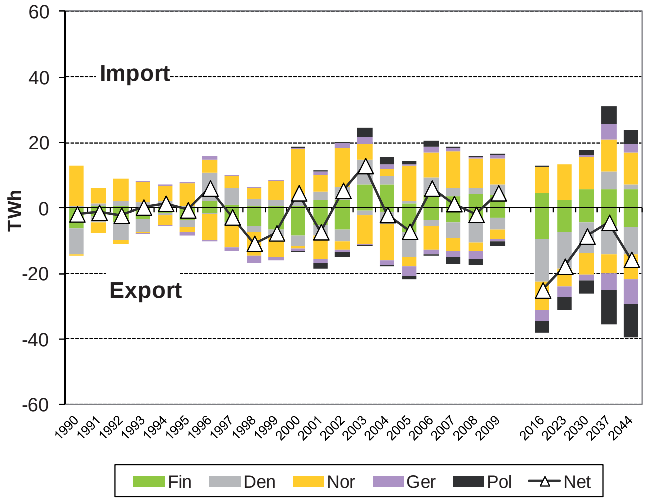


Figure 3.12a: Swedish electricity trade, Climate policy scenario

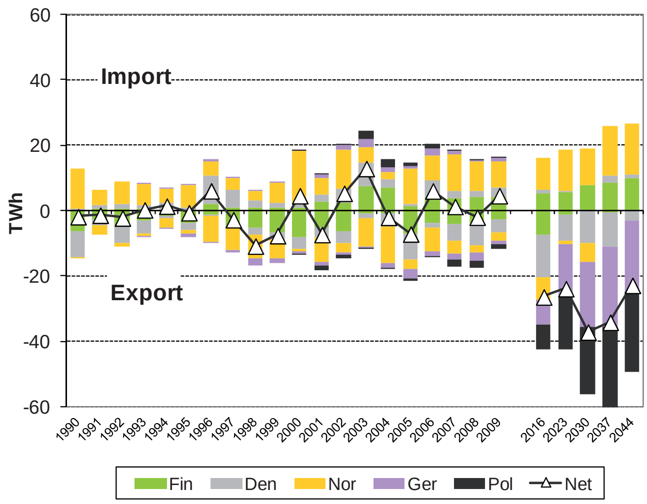


Figure 3.12b: Swedish electricity trade, Green policy scenario

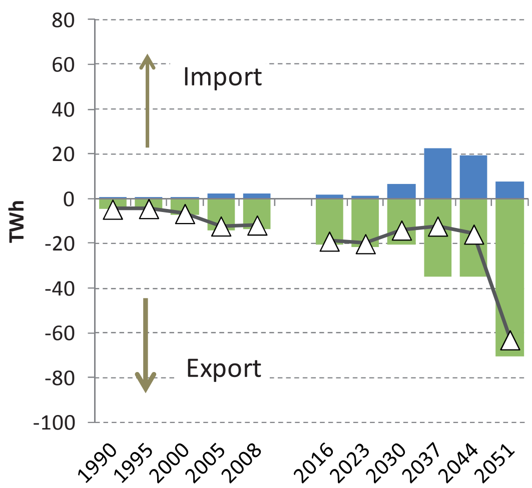


Figure 3.12c: Nordic electricity trade, Climate policy scenario

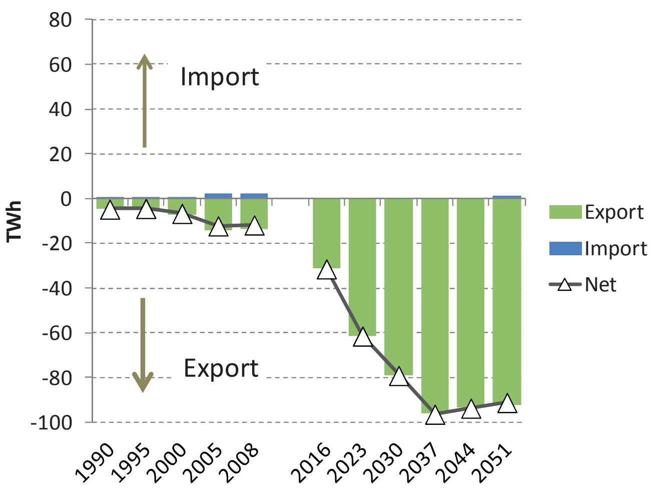


Figure 3.12d: Nordic electricity trade, Green policy scenario

3.5 Electricity prices

The electricity prices have been briefly discussed above. Here we compare electricity prices for the different scenarios. When we discuss electricity prices it is in specific situations important to make a distinction between system prices (wholesale prices) and final use prices (retail prices). The difference appears when we apply an electricity certificate system to support renewable electricity generation. In that case the final users, in addition to the system price of electricity, will have to pay for a fraction of the electricity certificate. The fraction is defined as the quota between the specified renewable electricity generation from plants included in the system and the electricity use for the users included in the system. If the support system is arranged differently this additional price component may not exist. If, for instance, the government offer a specific support related to the renewable electricity generation and where the financing of this system is not related to electricity use, then no price will be added to the system price. Such a design typically results in lower retail prices than in a situation without support. If such a support system however, is financed through a general fee on electricity use the result would be similar to the situation described for the electricity certificate regime.

We begin by showing the development of the system price in the four scenarios.

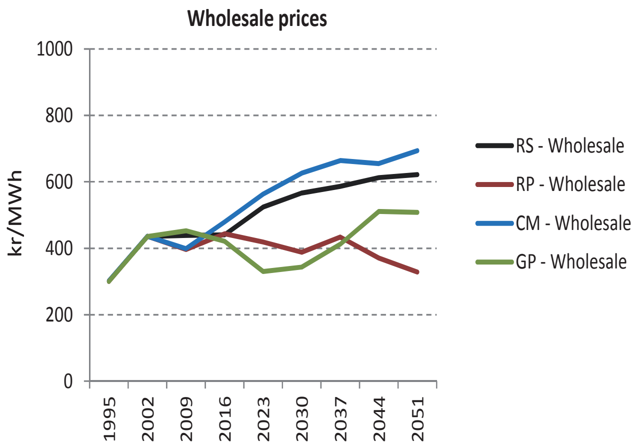


Figure 3.13: Nordic electricity wholesale prices in the four scenarios

As shown in the figure above the scenarios that include specific support systems for renewable electricity generation result in the lowest electricity (system) prices. The lowest price is found for the Regional policy scenario, characterized by large support for renewables and low electricity demand. The Green policy scenario also exhibits low prices, but here rapid increase in electricity demand results in a slightly higher price, at least in the long term.

The highest electricity price is found for the Climate market scenario. Here the desired development is motivated simply through a CO_2price. This CO_2-price increases the costs for all fossil fuelled plants and thereby increases the electricity price.

If we assume that the support levels for renewable electricity generation used in the Regional policy and Green policy scenarios are achieved by means of an electricity certificate system the retail price for users included in the system will increase. If we assume that all users are included in the system and pay a fraction of the electricity certificate price on top of the system price of electricity the retail price increases. The results are shown in the figure below.

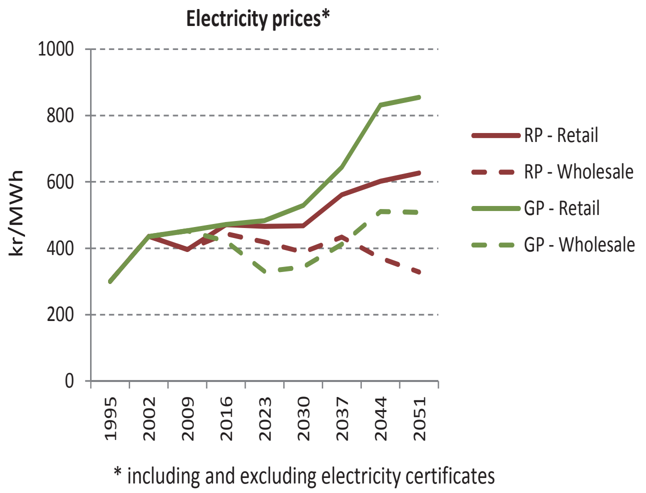


Figure 3.14: Nordic electricity retail prices assuming all users included in the certificate system prices, two scenarios

Here the prices increase to levels similar to those seen for the scenarios without specific support systems for renewables. The Green policy scenario stands out somewhat with higher retail prices. This is also the scenario with the most dramatic transformation of the electricity generation mix in a renewable direction.

If we instead assume that only a fraction, approximately 50 %, of the electricity users would be included in the electricity certificate system and forced to pay for a fraction of the electricity certificates, the retail price for those customers would, of course, increase even further. This situation is shown in the figure below.

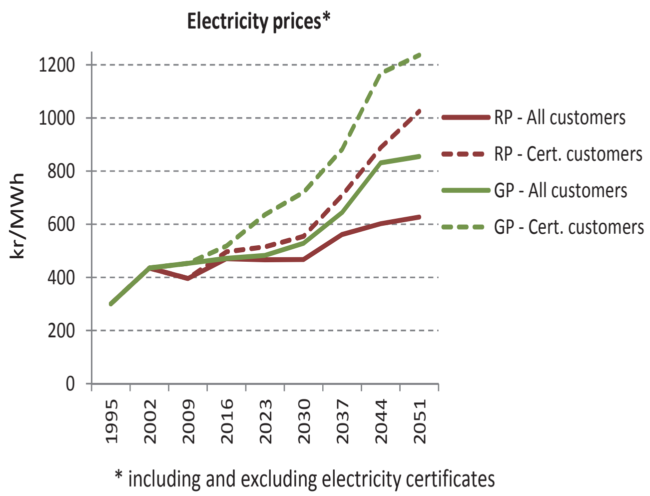


Figure 3.15: Nordic electricity retail prices assuming a fraction of the users included in the certificate system prices, two scenarios

Here the long term retail price reaches 1200 SEK/MWh in the Green policy scenario and 1000 SEK/MWh for the Regional policy scenario. The other electricity users can in these cases enjoy fairly low electricity prices.

In this chapter we have presented electricity system results from model calculations for a number of scenarios. Most scenarios are characterized by relatively large changes of the electricity system. Below we discuss the nature of the changes and the implied adjustments in principal terms. This includes a discussion about the need for reserve capacity, which is found to be less of a technical and more of an economical challenge.

A development characterized by a large introduction of variable/intermittent electricity generation may also lead to a need for changes in the electricity market model. This is discussed in chapter 4.

For more information:
Thomas Unger and Håkan Sköldberg, Profu

3.6 The effect of cross border trading cannot be ignored when effects of new electricity generation in Sweden is considered

In the debate surrounding new investment in renewable generation, especially wind power, it is common to hear statements like "X TWh of additional low marginal cost generation capacity in Sweden will depress Swedish electricity prices by Y SEK/MWh". Often, the effects of cross-border trading are overlooked, but the validity of such statements cannot be properly assessed without considering the impact of cross-border trading.

Because of cross-border trading, the price of electricity in Sweden is determined not by the marginal costs of the most expensive plant needed to meet demand in Sweden, but by the marginal costs of the most expensive plant needed to meet demand in the interconnected system. Therefore, in spite of the Swedish generation mix being characterized by low short-run marginal costs - nuclear, hydro, combined heat and power (CHP), and wind - the price of electricity in Sweden is generally determined by the marginal costs of more expensive thermal generation in neighboring countries, and by how much of this expensive generation can be replaced by cheaper imports to these countries.

Exactly when to displace thermal generators - right now or in the future - is a matter of choice for Swedish hydro producers, as water can be stored and producers can therefore schedule their generation strategically. Hydro generation is therefore valued at its shadow cost, i.e. at the marginal cost of the price-setting marginal plant it could be replacing in the future, subject to water constraints. We are normally assuming that we have a "perfect market" where generators bid at their marginal costs and hydro producers use these marginal costs as input for their bidding based on water values. This assumption is normally used in simulation programs, although some programs also assume some level of market power.

To verify that statements such as "X TWh of additional low marginal cost generation capacity in Sweden will depress Swedish electricity prices by Y SEK/MWh" are true, the usual procedure is to compare the "original" system with the "new system", i.e. the original system + X TWh. The "consequence" of additional generating capacity is then given by the difference between the results obtained by running these two different scenarios. When modeling, the following properties of the Swedish electricity system have to be taken into account:

a) Demand, not being very price sensitive, will be about the same in both scenarios.
b) Electricity generation in the other Swedish units, except hydro power scheduling, remains roughly the same. This is because foreign thermal price-setting units have higher marginal costs than Swedish price-setting units, so any additional cheap Swedish generation will primarily displace foreign price-setting units.
c) Hydropower resources will be scheduled differently depending on whether the additional capacity (X TWh) is wind, nuclear or CHP. Wind power generation is variable, but the amounts generated are higher during the winter, thus lowering the need to reschedule hydropower production from summer to winter. Nuclear output is rather constant throughout the year, which requires rescheduling hydro production from summer with low demand, to winter with high demand. CHP has a rather constant output during autumn-winter-spring.

With these conditions modeling shows that *adding new low marginal cost capacity to the Swedish system will only affect net exports (or net imports)* since the other factors in the energy balance are more or less fixed, and:

Original production + X + import = demand + export

Whether an additional X TWh results in "more export" or "less import" depends on the energy balance in the original system. Moreover, statement 1a is true only as long as the additional X TWh do not depress prices in Sweden to a level below that of the marginal cost of the "original" system. This can potentially happen if nuclear or CHP generation decreases.

What will the impact of an additional X TWh be on prices? This will often depend on the steepness of the slope of the supply curve of neighboring countries. A steep slope means that the price variation of the displaced generation is considerable, so increased Swedish exports will indeed lead to considerably lower prices in Sweden (and throughout the rest of the interconnected system). If slopes are gentler, the decrease in price will not be as dramatic.

It should be noted that Swedish exports could be limited by several factors such as constrained interconnections or low hydropower supply during dry years when Sweden imports. Furthermore, an increased penetration of demand flexibility measures will also affect the impact of additional generation capacity in Sweden.

In summary, the accuracy of the statement “X TWh of additional generation capacity will depress electricity prices by Y SEK/MWh” will depend on several factors, most notably the steepness of the supply curve of the electricity systems to which Sweden is interconnected. This is valid for all additional generating capacity with low short-run marginal costs and is not limited to wind power.

3.7 Is it possible to use existing resources for more balancing purposes or will it be necessary to invest in new reserve capacity?

As the volume of variable renewable generation such as wind power and solar power continues to increase, more flexibility in the form of modified generating schedules for other units or more demand flexibility will be required in order to continually balance the electricity system to match supply and demand.

Concerning the needs of reserve power, one has to consider the definition of “needs” and “reserve power”.
We first start with “reserve power” where it is important to separate between variability and uncertainty:

We first start with “reserve power” where it is important to separate between variability and uncertainty:

1. Variability - which is obtained from load changes and wind power changes. The variability can be studied by just looking at time series of historical true consumption and production. The variability has to be met with regulation, i.e., other power plants that follow the net load, i.e., load minus wind power. Regulation is needed no matter the accuracy of the forecasts, i.e., even if the wind, solar and demand forecasts are 100 percent reliable, the system still needs the continuous balance between supply and demand, i.e. “regulation”.
2. Uncertainty - which is obtained from the difference between forecasts and real outcome for load, wind power, solar power, thermal power (outages) and interconnections (transmission outages). The uncertainty is met with reserves, i.e., power plants that are keeping margins in order increase or decrease its production if there are unforecasted changes in load, wind or outages in power plants or interconnections to other systems.

This strict definition of “regulating power” and “reserve power” is not always applied in different texts, but in order to understand the system challenges it is important to separate between forecasted changes (“variation”, which mainly requires ramp rates but not “margins”) and unforecasted changes which require margins and in some cases these margins are kept for a long time without being used.

This is mainly important in systems with, e.g., coal or peat power, where the ramp rates are comparatively low (range of hours), which means that one in the unit commitment phase of the planning has to heat up some units (at a certain cost) in order to keep them ready if they may be needed, i.e. to “keep enough reserves”. In the Nordic power system most production control is performed in hydro power plants and these can change the production within some minutes from zero to maximum or vice versa. There is, however, a “river inertia” in Sweden (not so much in Norway), where sudden changes in use of water in one station will affect the next station in the river since this will change the amount of water to that station.

Concerning needs of reserve power at larger amount of wind power it is then important to consider the distinction between technical and economic needs.

Technical needs means that if these needs are not met then the power system will be less secure in its operation. This issue can be a challenge in thermal power systems where ramp rates may be a limit, i.e., if wind power decreases at the same time as load increases then there must be capacity enough to follow the net load increase with a certain MW/minute. Another issue is that there must be enough installed capacity (defined as high load reserves). In general: If a “technical need” is not met then one has to disconnect consumers that were not prepared for this.

Economic needs means that there is economically efficient to, e.g., invest in new regulating capacity, e.g., more installed capacity in hydro stations, new gas turbines, investments in higher ramp rates or lower minimum production etc. in thermal power plants.
Concerning the issue of need of more regulating power it is also important to consider that there is a basic competition between three technologies:

A. Production flexibility: This means more capacity in regulating units, e.g. higher ramp rates or new controllable units

B. Consumption flexibility: This means more flexible consumers, so-called Demand Response – DR. There are formally three methods to handle this: B1: consumers have the possibility to react on price which then means that they must have at least hourly measurements and see the price (dynamic grid tariff , day-ahead, intra-day or regulating market prices etc). B2: consumers have a voluntary contract with grid owner/retailer/trader where the consumer's counterpart can send out a control signal to change the consumption. B3: There is in the law stated that the consumers have to be "controllable", e.g. disconnect a certain consumption when frequency is lower than 49,8 Hz.

C. More and flexible transmission: This means that the total need of counter balancing is reduced since all changes over a large area do not vary in the same way so the proportional changes are reduced.

One example of a competition between solution B and C : Assume, e.g., that one in western Denmark (sometimes negative prices) invest in DR, e.g., electric heating of district heating in situation with negative prices. In this situation EU decides to invest in a "super-grid" with strong interconnections all over Europe. Then there may be a very low value in the DR investment since there will not be low prices so often.

Back to the initial question - is it possible for an existing system to be used for higher balancing needs without an automatic need for investments?

Consider four different situations

	High Demand	Low demand
High wind	1	2
Low wind	3	4

First looking at the "variability" challenge:
The real challenge from an investment point of view is situation 3 (low wind, high demand). If there are sufficient investments to cope with that situation it is likely there are enough investments to handle the other three situations. But since the changes in net load can be very fast we also need to consider the ability of the controllable generation to regulate their output fast enough to meet these change. This is usually not a problem in hydro based systems like the Nordic system but a bigger challenge in thermal based systems. e.g. coal-fired power stations, as these need time to heat up and may have limitations regarding the ramping up speed in MW/min. Hydro power often can move from zero to full production in a short time, 5 to 10 minutes, but how short this time is depends on a number of different factors, such as water supply, conditions due to water legislation, current operational mode and technical solutions of the individual plant.

Focus in hydro based system must be on peak load situations. Even if there are available generation in hydro plants to the variability in the system this capacity may be locket in due to network constraints. It is probably here DR has its greatest value.

However, also situation 2 is important for system dimensioning point of view. High wind and low load will lead to low prices, which mean that there is an incentive to increase the demand in these situations and/or have more transmission to neighboring systems. If these solutions are implemented then this implies more flexibility also for other situations.

The second issue is the uncertainty challenge:
As mentioned above this is mainly about the need to re-plan the system due to inaccurate prognosis in demand and wind generation. In a hydro based system this challenge is really limited to a situation with high demand and low wind and when wind power is decreasing even more. Once again the challenge is to have enough generation in the system during peak demand situations.

The studies performed so far for Sweden has shown that there is not a "technical need" for investments in more transmission or more regulating power in hydro power. This is based on a study where up to 30 TWh (total of 12000 MW) is added to the existing Swedish system (i.e. same demand and other power plants as today). The large challenge is what will happen with existing capacity in the system. Will it be kept or will it be decommissioned due to few expected operation hours adding to the need of an increased strategic reserve or other market design initiatives. More wind power will increase uncertainty in the planning of the system and by that increase the need for "reserves", but this will not automatically result in a need for investments. The reason is that the flexibility in existing hydropower. The only critical situation is during situations with very high demand and very low wind and when wind decreases even more.

For more information: Lennart Söder, Electric Power Systems, KTH

4. Four Market Design scenarios

4.1 Introduction

Throughout the European Union, national electricity markets are implementing significant modifications to their market design in order to align with the common European Target Model upon which the single European electricity market is to be founded. The Target Model reflects the prevailing market design in Europe. Nord Pool is the prime example. However, Europe's commitment to deliver a progressively high proportion of electricity generation from renewable energy sources means that a very different energy system than the current is emerging. The prevailing market design in Europe does not necessarily deal with high renewable penetration adequately. Renewable energy sources are often intermittent, have low short run marginal costs and are often located far away from load centers.

Intermittency implies that while renewable generators have the potential to generate large amounts of electricity, it is difficult to rely on them, and greater amounts of total installed capacity are needed to meet a given security of supply. However, in a system with large amounts of renewable generation, renewable generation's low marginal costs will depress the average wholesale price of electricity, making it more difficult for conventional plants to recover their costs. As they will be running considerably less, they will be relying on high but uncertain price spikes to recover their costs. There are growing concerns that this could lead to underinvestment in conventional capacity without some form of intervention.

However, there is still ongoing debate as to how to best respond to this challenge. Will the current market design stand up with only smaller adjustments, or will there be a need for a more fundamental redesign of the market?

In addition to concerns about securing investment both to maintain existing generation and to encourage the development of new sources of capacity, several other issues deserve attention. Large variations in generation over both time and space will further strain the electricity networks, making the efficient expansion and utilization of the grids increasingly important.

Finally the volatility in electricity generation is also likely to lead to volatile electricity prices. Price spikes are likely to be higher under systems with large amounts of renewable generation as conven-tional generators will have to recover their costs during fewer hours. Public opinion and the media have little or no understanding of this fact. Furthermore, price spikes that significantly exceed the marginal cost of the last generator needed to meet demand can lead to accusations of anticompetitive and manipulative behavior and calls for price caps. Price caps are already in place in several countries.

How electricity markets will evolve will depend on the decisions made by investors and policymakers. Will investors be willing to accept (risky) investments based on electricity prices that risk being more volatile and possibly lower on average, or will they be discouraged to invest in generation capacity? Will politicians (and regulators) rely on the markets even if this result in volatile prices, or will they opt for an interventionist approach with more detailed regulation and central planning? Will the scale of the investment challenge simply force politician to interfere?

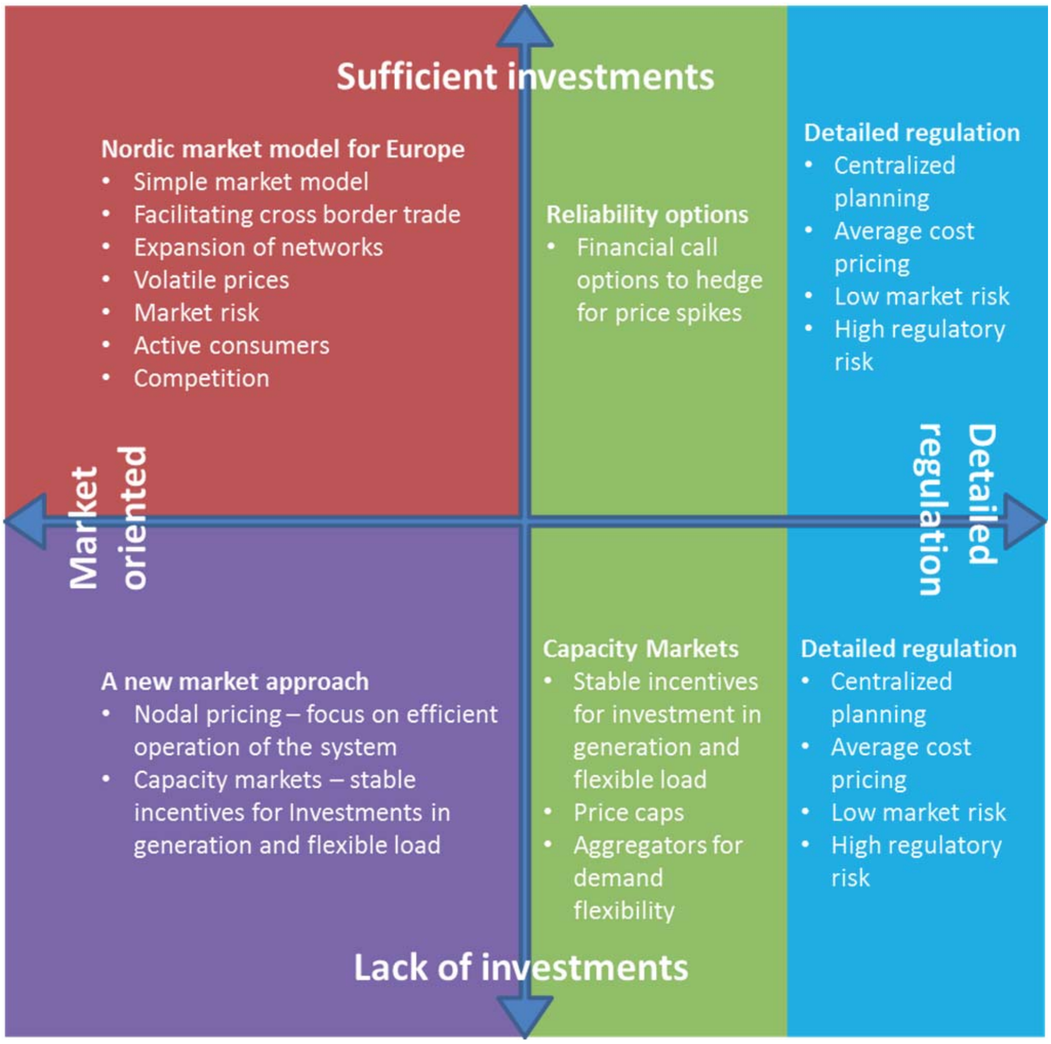
Based on this we see four different market design scenarios:

1 **Energy-only** (the Nordic market model for Europe)

2 **Capacity market** (addition of a separate capacity market creating income for capacity even if not used)

3 **Locational Marginal Pricing** (a combination nodal pricing that incorporates the costs for network losses and network congestion into electricity prices and locational capacity markets)

4 **Detailed regulation** (increased central planning and consumer price based on average cost)



The first scenario is a continuation of the current main trend with implementation of the European target model. This model does to a large extent build on what can be labeled as the "Nordic market model", although there are some differences and the model has already to a large extent been implemented in several different countries. This is a likely model if the model succeeds in attracting sufficient capacity and with a main focus on efficient markets.

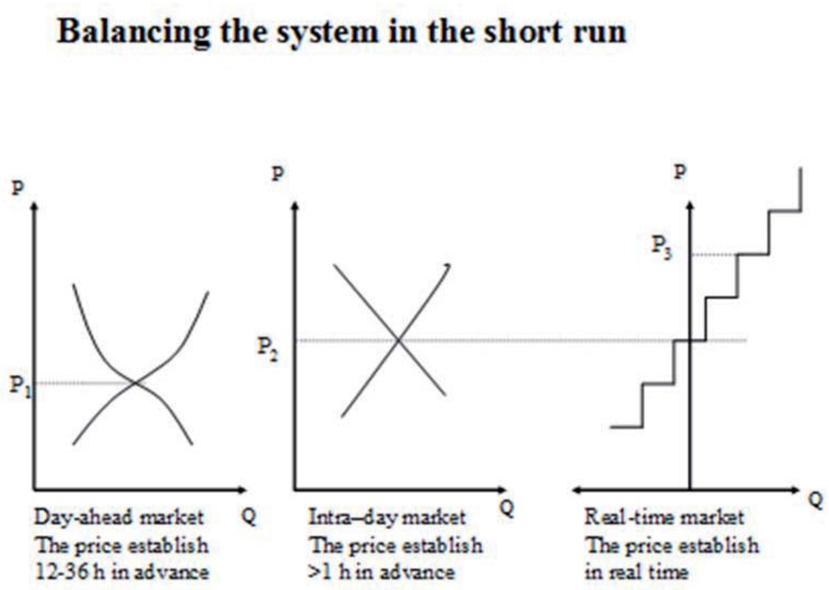
However, even if the market as such is able to attract sufficient new investments, it is highly probable that the prices will be very volatile (and occasionally very high). While this is not a security of supply issue it may lead to problems with market power or simply that the volatile prices are seen as politically unacceptable. A change of the market design may then be triggered. We then see three market design alternatives.

One alternative is the introduction of a capacity mechanism with financial call options that provide a hedge for high prices. This would lead to more stable prices (and support investments). This option still relies to a large extent relying on markets, even if involves more central planning. The third alternative is similar to the second but here we add a locational marginal pricing scheme to encourage efficiency in the location of new generation investment and in the dispatching of all generation. The fourth alternative, detailed regulation, involves increased central planning, long-term contracts for new capacity and possibly a return (or the continuation for several countries) of regulated end-user tariffs. The reason for this approach is not primarily physical security of supply, but rather a reluctance to accept volatile prices, an urge to create a low risk environment for investors and a belief that consumers will gain from regulated average prices rather being exposed to market prices.
If the current market model is unable to attract sufficient investments, and end in a (perceived or real) security of supply problem it is likely that the model will be challenged and replaced. If this is combined with a lack of trust in market solutions the detailed regulation scenario is the likely outcome. The solution may to a large extent be similar as with the detailed regulation in the upper right quadrant, but the underlying motives differ. In this situation it is more important to handle the physical security of supply. With somewhat more trust in the market we instead expect a situation with some type of capacity mechanism.

If we move more towards a policy situation where there is more focus on market solutions, and efficient markets we still expect that some type of capacity mechanism will be part of the solution. In addition, with an electricity system under pressure in combination with a trust in markets and price signals we expect that there will be a willingness to expose market participants (producers and consumers) to the correct local prices. Adopting locational marginal pricing would imply a new market approach for Europe, but one already adopted by a wide range of electricity markets, most notably in the United States.

4.2 Nordic Market Model for Europe

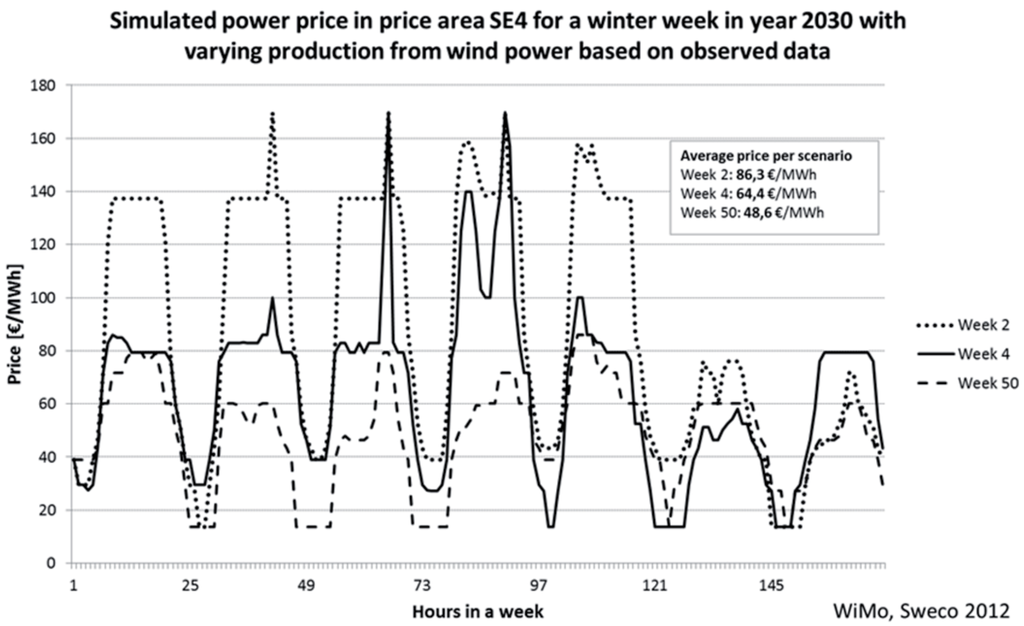
The European Target Model to encourage harmonization of European wholesale market arrangements is basically an "energy-only" market model in which trading takes place in four time-frames: a forwards market, an auction-based day-ahead physical market, an intraday market with continuous trading and a balancing or real-time market run by the Transmission System Operators (TSOs). Its prime example is the Nordic electricity market.



The purpose of the short-term markets is to create incentives and tools for the market players (producers, suppliers, and consumers) to sell and purchase physical wholesale power efficiently through a common platform, and to participate in the balancing of the system. There should be reasonably strong incentives for market players to behave in such a way that there is a balance between power generated or purchased and power sold. A perfect balance is not possible to achieve and that is the reason why real-time markets operated by the TSOs are needed. (Unavoidable) imbalances between contracted volumes and actual load and generation are settled ex post.

In this “energy-only market” generators only get paid when they generate. This is the case for all three markets day-ahead, intra-day and real-time. To make sure there is a minimum level of reserves in the system for the (TSO) to operate the system safely, generators may get paid for allocating resources (standing ready to generate but not actually generating) through special arrangements administered by the TSO. In Sweden these reserves are primary reserve, fast disturbance reserve and strategic reserve. This type of “capacity payment” exists in nearly all markets, even in so-called pure energy-only markets. The important thing is that these reserves don’t affect the market prices.

A typical characteristic for energy only markets is price volatility. Volatile prices are necessary in order to attract necessary investments in peak generation and in demand flexibility.



The day-ahead markets have also a very specific role in the allocation of cross-border transmission capacity and thus facilitate trade between countries or between price areas within countries. The idea is that power flows between countries shall be a result of decentralized decisions made by generators and consumers. Capacity between countries (or regions) is used to minimize the price differences between the markets. From a practical point of view this is done through the use of a common day-ahead-market (like Nord Pool Spot for the Nordic countries) or through close cooperation between market places often referred to as “market coupling” or “price coupling”.

Forward markets are a complement to the short-term physical markets. The forward markets can be based on physical delivery or financial settlement. The forward markets are basically free to develop as seems fit, while the short-term physical markets must have a common design to be able to facilitate cross-border trade.

The Swedish strategic reserve

The Swedish strategic reserve is a good illustration of the importance of defining the TSO’s role in the market, and of the difficulties associated with introducing capacity payments in an energy-only market without introducing significant market distortions.

The Swedish TSO is mandated by an act of Parliament to each year tender for a strategic reserve of up to 2,000 MW, in the form of both generation and demand side resources This arrangement was introduced in 2003 as a temporary solution to address concerns that the market alone would not provide sufficient incentives to maintain reserve capacity. The cost of the strategic reserve is financed by a levy on the balance responsible parties. At present (Winter 2011/2012) the total reserve is 1,726 MW of which 1,364 MW is generation and 362 MW is demand reduction. The plan is to gradually reduce the share of generation facilities and, by the end of the period, only have demand resources in the reserve.

Stimulating demand side flexibility is a supplementary objective for the reserve. The main reason for this is that it is expensive to keep reserve capacity for situations that are expected to occur very seldom – it is cheaper to encourage large customers to reduce their consumption. The other reason is that increased price sensitivity creates the conditions for a more stable and more predictable pricing development in strained situations.
The rules governing the dispatching of the strategic reserve have changed over time. The strategic reserve was originally designed to cover supply gaps. In order not to crowd out pure commercial investments, it was not meant to affect market prices. This design was later reviewed to allow the TSO to bid the strategic reserve into the day-ahead market in shortage situations. The clearing price on the day-ahead market is then set as the price of the last commercial bid plus 0.1 EUR/MWh. Reserves not used on the day-ahead market can be sold into the real-time market, but only after all commercial bids have been used.

During the 2009/2010 and 2010/2011 winters, the Nordic market suffered from significant capacity shortfalls; mostly notably of Swedish nuclear power. Unusually cold temperatures pushed up consumption leading to a difficult supply-demand balance. The strategic reserve occasionally had to be called upon to secure that the day-ahead market cleared, and prices peaked at very high levels. Nord Pool and the Swedish TSO later acknowledged that the fact that the strategic resources were dis-patched after all commercial bids at Nord Pool had been used had been less than optimal. Because demand is inelastic, supply shortages - whether real or due to market power - have the potential of driving prices to levels many times higher than normal level as the cost of the next highest generation to satisfy demand exceeds the market price by increasingly larger amounts. The last commercial bids were very small in volume, and had a disproportionally large impact on the electricity price. Nord Pool and the Swedish TSO concluded that demand reduction reserves should not have been withheld from the market.

From this experience some potential problems were identified:

- The current mechanisms may contribute to withholding capacities from the market that would otherwise be bid into the market on a commercial basis,
- The current mechanism does not contribute to reduce the possibilities for generators to exercise market power. Restricting output can be very profitable, and the risk for market power increases.
- The current mechanism may disincentivize consumers from placing demand reduction bids at high prices as this could contribute to increasing prices.

As a result of these observations, demand side strategic reserves are now allowed to freely bid into the day-ahead market and contribute to price formation. This change does not apply to generators. The motivation is that these generators would not be available without support, while the demand side reserves probably would. Allowing them to bid into the day-ahead market is intended to stimulate the development of an active demand side.

4.3 Capacity Markets

There are several different types of capacity mechanisms, but the underlying common theme is that there is a separate payment for capacity that is paid independently of whether the capacity is used or not. In very broad terms there are two main types of mechanisms. One alternative is to have administratively determined capacity payments and the other is to have centrally determined capacity margins. The first one could thus be seen as a price mechanism while the second is a quantity mechanism. In the remainder we will focus on the quantity mechanism.

With a quantity mechanism a central party (e.g. TSO/ISO or regulator) determines a required margin. This margin is typically determined so that a required loss of load probability is upheld. The margins can either be defined for the current situation or be requirements of future margins based on the expected load growth. The later has become more popular as it facilitates investments in new capacity and increases the competition in the capacity markets as more parties are able to participate in the market.

The reserve margins are distributed to the load serving entities that are required to meet the requirements either through own resources, bilateral contracting or through a centrally administered capacity market. In some capacity markets (e.g. ISO New England) there is also included a call option (also called reliability contracts). This implies that the holder of the call option is paid the difference between the market price and a defined strike price, if the market price exceeds the strike price. This provides a (compulsory) financial hedge for the consumers, but also transforms a volatile revenue/cost stream to a more stable for both producers and consumers.

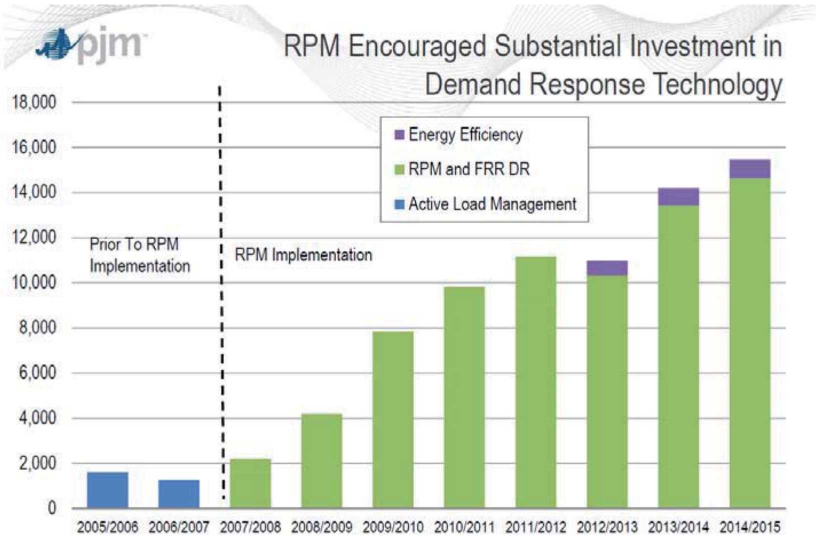
Capacity markets typically include all types of capacity, both different types of generation and demand side resources, but the capacity that can be offered as a share of the installed capacity will depend on the technology (the probability that the resource is not available when called upon). It is also possible to only allow certain technologies to take part in the capacity mechanism. If for instance flexible generation/demand is important one could choose to only include technologies that are flexible (e.g. nuclear or intermittent generation would not be allowed in the system). The risk of choosing that path is of course that it may distort investments.

The table below provides some examples of market areas with different types of capacity mechanisms (not exhaustive). In addition several countries in Europe are planning to introduce capacity mechanisms. Both UK and France have decided to introduce sector wide quantity based mechanisms (by 2015), and Poland is planning to do the same. The discussion is also ongoing in e.g. Germany. In April 2012 a report commissioned by the German Ministry of Economics and Technology advocating a capacity market was presented.

	Administratively determined capacity payments	Administratively determined reserve margin re-quirements with capacity market	Reliability contracts
Variations	• Availability requirements/ penalties	• Future requirements • Locational differentiations • Central market	See reserve margin
Example	Spain, Portugal, Ireland, Italy	Several US markets (PJM, ISO-NE, NY-ISO, Brazil, Greece)	ISO-NE

Essentially the power market offers two products, where one is the energy and the other is capacity. The question whether a separate (and explicit) capacity payment is necessary in addition to the payment for energy has been discussed for a long time, and the debate is ongoing. In theory the energy- only market should be able to function by itself, but it requires a very well-functioning market. For example the demand side needs to be sufficiently active/flexible and there cannot be any price cap. Even if this is fulfilled the risk profile may make investments based only on energy prices risky. This may delay investments or lead to investments in less capital intensive technologies. It also relies on high price spikes to pay for peak load investments.

So even if the energy only market may function in theory a capacity mechanism could be beneficial. A quantity based mechanism will ensure a certain reserve margin, which is likely to lead to increased security of supply. Investment risks could be reduced, leading to reduced capital return requirements and thus lowering the cost of investments. In addition it could allow for more capital expensive technologies. With increased capacity margins price spikes are likely to be reduced, and in addition the possibilities to exert market power in shortage situations will diminish. Experience from markets with capacity mechanisms also indicate that they are fairly successful in attracting demand side resources. The graph below is taken from the PJM market and shows the increase in demand response technology as part of their current capacity mechanism. It shows a very strong increase since 2007/08. However, also before that PJM had a capacity mechanism, which was clearly not as successful in attracting demand side resources. The design of the mechanism is thus crucial.



On the negative side is that capacity mechanisms typically require quite detailed regulation. It is naturally necessary to define reserve margins (or the capacity payment if it is a price-based mechanism). In addition it is necessary to define what technologies can be included and in what way. It can be debated whether it is necessary to control the actual physical backing of the resources or if a financial backing is sufficient, but most (if not all) markets that have such mechanisms have opted for a physical backing, that needs to be controlled. In a quantity-based mechanism the prices can become very volatile, which was the case in PJM before the introduction of the existing mechanism. Support to investment is also facilitated if the mechanism is forward looking, which requires the regulator or TSO to have load forecasts for different load serving entities. There is thus a risk of "micro management" of the sector. The outcome is also highly dependent on the details of the design, which implies a high risk of regulatory failure.

4.4 Locational Marginal Pricing

Locational Marginal Pricing (LMP), sometimes called nodal pricing, is a method where costs for network losses and network congestion are incorporated into electricity prices. The purpose of LMP is to make sure that generation is placed at the right location. It does this by making the costs of network losses and congestion explicit in electricity prices. LMP has been adopted by several markets in the US as well as markets in Australia, New Zealand and Russia.

LMP is based on a marriage between electricity market clearing and system operations. In most elec-tricity markets in Europe these are separate activities - market participants submit bids to generate and consume electricity, and these are then used to compute one equilibrium price and a set of schedules for an area. The schedules are then analyzed by system operators to see if they are compatible with known network losses and transmission grid constraints. If schedules are not compatible with the current state of the grid, system operators perform countertrades, that when added to the schedules received from the exchange, produces a new set of schedules that is compatible with the state of the transmission grid. In the integrated Nordic market, the approach - market splitting – is rather different and resembles a simpler form of locational marginal pricing. The Nordic countries are divided into bidding areas. A System Price that ignores internal congestion is first determined, and if the dispatch schedule is feasible, all bidding areas have the same price, but if not generation units will be redispatched to solve the transmission constraints, and the prices that clear each bidding zone will be different.

As mentioned before, LMP merges electricity market clearing and system operations. An LMP algorithm is based on a complete model of generating capacity, transmission grid capacity, and load characteristics. Given a set of bids and offers and their locations, it computes, for each point on the grid where electricity is injected or withdrawn, a price of electricity that reflects the true cost of satisfying load at that location, given existing grid constraints and network losses. In the absence of network losses and grid congestion, the price at all nodes is the same, but otherwise prices at different nodes will be different. In the presence of congestion, prices in surplus nodes will fall, and prices in deficit nodes will rise, as cheap generation located on the wrong side of a congestion point is replaced by more expensive generation located at points on the grid from which it is actually possible to reach the load.

Generators are paid the price at the location where they inject, and loads pay the price at the location where they withdraw electricity. LMP thus forces consumers to pay for the actual cost of not only the production of the electricity consumed, but also its transport in a possibly constrained grid. In an LMP regime, generators are paid exactly the value that their generation provides given grid constraints. The costs for managing grid constraints are no longer socialized among all market participants, but are instead borne by the individual generators and consumers. It punishes generators that are located far away from consumers, and consumers that are located far away from generators. Locational prices also clearly signal where grid constraints are present, and can thus be used to guide investments decisions in transmission grids.

The fact that LMP involves simultaneous market clearing and system operation implies that one organization should do both. In the US, Independent System Operators (ISOs) are both market places and system operators. ISOs run real time markets that are open right up to delivery time, and the LMP algorithm is applied the whole time. These markets are essentially a hybrid of intraday and real-time balancing markets used in the EU. The day ahead market (in Europe often labeled as spot market) is considered a forward market in LMP markets in the US.

The fact that congestion can cause unexpected and significant price differences between nodes can pose considerable risk for market participants. Market participants can hedge this risk by purchasing Financial Transmission Rights (FTR) that offset the effects of nodal price differences. However, there is potentially very large number of FTRs and few agents interested in any one of these FTRs. For this reason, nodes are sometimes grouped into zones within which there are few congested links, but between which congestion is important. An average price is then computed for each zone. In some LMP markets, zonal prices are used for demand side actors, and nodal prices are reserved for generators. Such systems are usually called Generator Nodal Pricing (GNP). The case for making the market zonal for demand side actors is that complicated loop flows may make independent retailers vulnerable to price volatility during periods of congestion.

Zonal pricing is the currently preferred option in the target model for the single European electricity market. Large price zones are less complex for traders as more generators and consumers face a common price, but the larger the zone the higher the re-dispatching costs of congestion management.

LMP has been criticized for being difficult and expensive to implement. Computing nodal prices at thousands of nodes in real time requires detailed and up-to-date models of loads, power plants, and transmission and distribution grids. Advocates of LMP argue that the information needed to compute nodal prices is the same information that system operators already use to plan the operation of the system, so no new data collection is required. With clever algorithms and powerful computers, the computations become feasible.

A related criticism is that the models that are used are just that – models – not reality. Furthermore, the LMP algorithm assumes that the generation prices that are received from generators are purely cost-based, and in a commercial market this may not be true. These two differences between theory and reality may make LMP-based market less optimal than suggested by advocates.

Another criticism is that nodal prices may not be as beneficial to transmission grid planning as claimed by LMP advocates. Even though nodal prices may indicate where investments are needed, transmission grids are still (for the most part) owned by regulated entities, and LMP does not in itself solve the problem of who should decide on, and pay for, such investments. Furthermore, the price signals in an LMP market may simply not be strong enough to guide transmission investment, even in cases where commercial merchant transmission owners make the investment decisions. Nodal price variations are usually very short term, and may not offer any guidance for investors contemplating investments with a 30-40 year lifespan.

LMP has also been criticized for being vulnerable to market power. In some cases such criticism is based on empirical studies of trading patterns in LMP markets and claims of possible market power are not backed up by an underlying theory. In other cases, a theoretical argument that LMP segments large markets into smaller markets and therefore gives market power to dominant generators in deficit nodes is put forward. Here the counter-argument is that market power is not an effect of LMP per se, but a consequence of real grid constraints. LMP only serves to bring this market power out into the open. The only thing a non-LMP system achieves is to spread the pain of market power among a larger set of consumers. This may be nice for the consumers that are close to the generators with market power, as they no longer have to face these generators alone, but it also hides the market power to some extent. When the pain is shared, the incentive to respond to market power by reducing demand is reduced. The incentive to enter into long-term contracts with new entrants into the generating market is also reduced.

Even though it is unclear to which degree LMP is vulnerable to market power or not, the mere possibility of market power has led to the introduction of price caps in highly constrained areas in some LMP markets, notably in the US.

With its insistence that costs for grid constraints should not be socialized, LMP does not seem to mix well with the idea of priority dispatch for renewables. LMP proponents point out that loop flow may lead to situations where massive injection of low carbon electricity at one location may force compensatory actions at unrelated parts of the grid that lead to overall higher carbon emissions. Proponents of LMP favor renewable support schemes that raise the price of carbon and that reduce construction costs of low carbon plants. Once plants are constructed, they should play by the same set of rules as all other generators.

Finally, LMP advocates claim that demand flexibility can only be truly successful in markets based on LMP with clear and sharp price differences between nodes. Where prices are averaged out over large geographical areas (such as zones), the incentive for end customers to participate in demand-response schemes are weakened according to the LMP advocates.

Capacity markers can be administered separate from LMP markets, but capacity markets can incorporate elements of locational pricing. For instance, PJM’s capacity market - called the Reliability Pricing Model (RPM) - holds a centralized auction three years before every delivery year to contract the capacity it believes will be required to ensure safe operations. Selected generators or demand-response loads receive a capacity payment independent of any actual delivery of energy. There is a locational aspect to the auction in that capacity that is offered at nodes that have traditionally experienced deficits are valued higher than capacity offered at other nodes.

4.5 Detailed Regulation

In the fourth and final scenario, governments return to central planning in order to reach the goals they have set out for the electricity sector. In this scenario, governments have given up on the ability of market forces to deliver the volume of investment in new generation and transmission capacity needed to achieve a low carbon, secure, and affordable energy system, and have conceded that the transformation must be driven by authorities.

While governments are not likely to turn on their heads and undo the privatization of the electricity industry in this scenario, governments have nevertheless accepted that introducing competition has been more complicated than expected, and that the decarbonisation objective they wish to pursue is a public policy objective that requires not only non-market viable investments, but also significant investment in plant to back up non-market viable, non-manageable generation. Governments have finally conceded that relying on commercial decision-making serves no useful purpose to the climate change agenda and merely increases risk, and therefore the costs to be borne by the public.

Governments will therefore resort, under this scenario, to far-reaching measures to steer the electricity sector in the direction they want. The old premise of deregulation, that market forces should be allowed to guide investments, is abandoned in favor of a system where investment is driven by central planning and subsidies. While there will still be commercial actors, their behavior will be largely controlled by governments, resembling times past when governments instructed their utilities to install a preferred portfolio mix.

At the same time, governments will want to ensure that the rules that are laid down will be in force for long periods of time, so that investors that are contemplating long term investments in the electricity sector can assume that the conditions are true when an investment decision is made will continue to remain true for as long as is required to make the investment profitable. Changes to regulation will always be accompanied by grandfathering clauses to protect existing investments.

The overall goal is to create an environment where the risks associated with investments in generation and transmission are reduced to a point where investors will feel comfortable to make the investments that will ensure security of supply and a decarbonized electricity sector. Another goal is that the transformation should be carried out in a manner so that costs to consumers are kept to a minimum.

Already we are seeing clear attempts at market interference, for different reasons.

In France, where nuclear generation enjoys a very high scarcity rent as a result of interconnections to Germany, regulated electricity tariffs that pass on the cost-advantage of France's ambitious nuclear program to consumers are still widespread, and have impeded the development of competitive retail markets. To remedy this situation, the French government has passed a law to reform the electricity market. The Law regulates the price of a significant volume of France's nuclear output by granting EDF's rivals supplying end-consumers the right to buy electricity generated by EDF's nuclear power plants at a regulated tariff set by the Government. In addition, the Law hints that future costs to replace the nuclear fleet, i.e. to build new plant, will be covered by a regulated item included in end-consumers electricity tariffs. It can therefore be argues that only investment in peak generation will be left to market forces. The Law also opens the door for the establishment of a capacity market.

Even the UK, who pioneered electricity market liberalisation, is intervening to de-risk investment by transferring some investment risk to electricity customers. The UK government has concluded that current electricity market arrangements do not provide the long-term market certainty for the large volumes of capital-intensive low carbon generation sources, including nuclear power, needed to de-carbonize the UK, ensure security of supply, and make sure that costs to consumers are kept reasonably low. Unlike the Nordic countries, the UK's share of renewables is low, and demand is expected to increase as the heating sector switches from natural gas to electricity.

The British Government has therefore presented a set of reforms. The key elements are long-term contracts in the form of technology differentiated feed-in tariffs, long-term price signals implemented though a carbon floor price, a capacity mechanism to ensure an adequate security of supply, and stricter environmental legislation to make sure that new carbon-based power plants without CCS (Carbon Capture and Storage) are not built.

The argument for a carbon floor price is that the carbon price of the EU ETS is too low, too volatile, and lacks longer-term credibility. The UK government does not believe that an EU-wide tightening of the EU ETS will come about quickly enough, so it has decided to use taxation to bring the price of carbon in the UK to what it describes as "sensible" levels - required to make low-carbon alternatives more attractive compared to the carbon-based alternatives. In addition, since the wholesale electricity price is set by coal or gas plus the cost of carbon, the effect will be to drive up the wholesale price, so investment in nuclear can happen without easily seen and possibly controversial subsidies.

As the French Government, the British Government is also planning to help nuclear energy into the market. A higher wholesale price and carbon taxation is not long-term enough - taxes that currently make an investment look attractive can be rolled back at any time, thus destroying the conditions on which the investment depends for its profitability. Instead, the government intends to offer long-term, legally enforceable contracts to new low carbon generation projects. The intent is that such long-term contracts that promise regular revenue streams over long time periods will make investments in low carbon alternatives attractive.

The long-term contracts being proposed by the UK Government are feed-in-tariffs based on Contracts for Difference. If the wholesale electricity price is below the price agreed in the contract, the generator will receive a top-up payment to make up the difference. If the wholesale price is above the contract price, the generator pays the surplus back. Because feed-in-tariffs will be technology differentiated, it can be argued that market decision-making is being replaced by the decisions of a central agency. A reminder seems appropriate at this point that a major argument for liberalization was that decentralized investment decisions would deliver the best outcome. However the proposed British system resembles the single buyer model in which a single buyer in the market holds periodic tenders for new capacity, with the winners signing long-term power purchase agreements with the single buyer.

Given the centralized, long-term contracting of all new generation (either through feed-in-tariffs or competitive tenders) the wholesale market price is no longer used as a signal for investment under this scenario. Achieving retail competition is no longer a major goal, and consumers can once again pay regulated tariffs. In a further step, abandoning decentralized contracting in favor of centralized pools might be considered, as several commentators argue that centralized dispatch is better suited to intermittent generation. Gains are made in simplicity, and transparent market prices make it easier to evaluate investment opportunities. However, this would mean abandoning the European Target Model.

4.6 How are different market designs reflected in the power system models used in the NEPP project?

The NEPP project uses several different computer models to optimize or simulate electricity generation in different regions. Examples of such models are: ELIN, EPOD, PoMo, WiMo, MARKAL, DC power flow (mainly grid).
Four important aspects differentiating these models are:

- Deals with investments or not
- Different time resolution within a year and with respect to number of years
- Regional scope
- Level of technological detail

Investment models typically calculate the development of the electricity generation system over a fairly large number of years. In order to keep calculation times reasonable, these models generally use rather simplified time resolutions, often less than 30 load levels per year.

Dispatch models deal with the most effective operation of a given generation system, and typically require a detailed time resolution, often hourly load levels. However, such models generally analyze only one year at a time. In terms of regional scope, MARKAL-NORDIC and PoMo only encompass the Nordic countries while the other models have a European-wide scope.

The models are typically designed to calculate the system and generation mix that satisfies a defined load at the lowest cost. Prices are generally calculated as shadow prices. Most commonly the models do not reflect an explicit ambition to illustrate a certain market situation.

It could be useful to reflect over how different models correspond to the market scenarios we have described in the preceding sections (Energy Only, Capacity Market, Locational Marginal Pricing and Detailed Regulation). Is it possible to say that a certain power system model reflects a certain market situation? Here we discuss this in principal terms.

A typical dispatch model with hourly resolution usually deals with a given production system and it is there for not really relevant to discuss the issue of energy only or capacity market. The set-up of the model can be made with or without the assumption of capacity mechanisms. The results from the dispatch model are prices based on short run marginal cost and in in real-world, marginal costs act as investment signals in energy-only markets.

Investment models used in the NEPP-project[1] use much coarser time/load resolution and in order to reflect realistic demand for capacity and investments, it is generally necessary to introduce some sort of capacity equation that forces the system to build and keep more capacity than the coarse load steps call for. This is not, however, an explicit attempt to describe a capacity market. Nevertheless, the model formulation may very well open up for specific analyses on issues related to capacity markets.

Of the market scenarios mentioned above, NEPP models thus tend to describe a situation that is close to the energy-only market. The model´s shadow price is here a representation of the electricity market´s system price. Depending on the time resolution the shadow price indicates average system price for the applicable time periods.

[1] *There are investment models that generate investments without a specific capacity equation.*

The investment models could, as mentioned above, be seen as prepared for showing a market situation characterized by a capacity market. The capacity equation could here be used to simulate such a market, specifying either a minimum installed capacity or a certain revenue (e.g. €/kW) for installed capacity. Increasing ”weight” of the capacity dimension will result in lower energy prices. The reason for this is that a part of the necessary income for the system to cover the costs is supplied through the capacity market, resulting in less need for income from the energy only market.

Since the dispatch models do not deal with investments they have difficulties in describing a capacity market situation.

The nodal pricing market design introduces much more of the grid and bottle neck dimensions in the market picture. Here one can foresee the use of grid models, e.g. DC power flow, in combination with generation models (including representation of investments) in an iterative process. The reason for the iterative approach is that there will probably not be one model available that represents both generation and grid well enough. The detailed regulation market situation illustrates a case where increased use of central planning is seen as a guarantee for the most effective operation and development of the electricity system. Here the different electricity generation models are still useful tools for calculating this optimal system. There will however, not be a direct link between the calculated shadow price and the market price of electricity. In this market situation the prices will probably be based on average costs. These may, however, be calculated based on the model runs. In conclusion the used models are not clearly related to one certain market situation, but the project´s model tool box is well prepared for analyzing important aspects of all market scenarios.

4.7 How to use models in simulations of the market models, an example

An attempt by Fortum, in collaboration with McKinsey, to model the effect of capacity markets is described in a report dated 31 January 2012 .

The report provides a simplified quantitative assessment of the implications introducing a capacity mechanism in 2014 would have on the European power market by 2020 [2].

The modeling is based on the power model Plexos [3] adopted by McKinsey’s for the European power market. Three cases are presented.

A) A base case that represent a pure “energy-only market”,
B) A European-wide capacity market, with a regulated target of 5% reserve for each country. All firm dispatchable assets get capacity remuneration.
C) Capacity market only in Germany

In the modeling, bids to the capacity market are based on the difference between what a plant is expected to get paid in the energy-only market and the plant’s total cost, including fixed, operational, maintenance and start costs. For new investments, capital costs are included in the bids to the capacity market.

Key results

Implementing capacity markets throughout the EU would result in investments in generating capacity totaling up to 47 GW (from 4 GW in the base case to up to 51 GW in the whole-EU case). The majority of these new investments would be in gas-fired generation. The annual cost to consumers is expected to be up to 10 billon EUR by 2020, implying an electricity bill increase of approximately 5%.

The report expects cross-border trade to decrease with the introduction of capacity mechanisms. In the EU-wide capacity market case, trade between the Nordic market and Germany is somewhat lower compared to the base case. (The effect on power flows on Germany’s southern and western borders will be larger). If a capacity mechanism is implemented only in Germany, power flows between Germany and the Nordic market are reduced by half.

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[2] *European power market design under pressure; Potential implications of capacity mechanisms to European power market development. 31 January 2012. Edited by Merja Paavola and Simon-Erik Ollus, Fortum*

[3] *www.plexossolutions.com*

The reasoning behind these results is that instead of relying on cross-border trade with neighboring countries, on active demand response, and on normal market-based peak load generation, capacity mechanisms will incentivize generators to invest in new capacity. Moreover, old capacity will not retire as early as it would in the base case.

Some comment on the report

The report assumes that a capacity margin of 5% is introduced in every European country. As to our understanding this is done without taking into account the already existing possibility to share capacity between countries (load will not peak at the same time and intermittent generation will not drop down at the same time). We assume that this effect is taken into consideration in the base case calculations. Cross-border trade could replace some investments in new capacity if this is done systematically.

The report also assumes that it is harder to develop demand response in an environment with capacity mechanisms compared to an environment with more volatile prices and price spikes that will characterize the present energy only market. As described above demand response can be successfully developed in markets with capacity mechanisms – examples of this would be the forward capacity markets in the United States where dispatchable demand resources can bid their demand response capability as a forward capacity resource. Indeed, some commentators argue that well-designed capacity markets are a necessary precondition for large volumes of demand response. In a Deliberation dated 29 March 2012 and concerning a the introduction of a capacity mechanism in France, the French regulatory authority states that the planned capacity mechanism is well-suited to solve the problem of how to remunerate demand reductions, as capacity markets provide the economic model that France's current energy-only market lacks and that allows demand response to put a value on its contribution to security of supply.

Finally, capacity markets in the Unites States provide locational capacity pricing, to attract new re-sources to constrained regions. Capacity markets with reasonable locational signals help reduce the pressure on the transmission networks and cross-border lines. This potential benefit is not included in the report.

4.8 Plug-in Electric Vehicle Charging Schedule and its Impact on the Spot Market Price

This section presents different scheduling mechanisms to charge a fleet of EVs and their effects on the market price in a day-ahead electricity market. The analysis is done assuming a future scenario where necessary and sufficient infrastructure is available to centrally control the charging of a fleet of EVs from the electricity network. The effect of EV participation in the electricity market is modeled as a flexible demand using two approaches namely: Joint scheduling and Aggregator scheduling. The most important aspect of the Aggregator scheduling model is that it reflects the structure and working of Nord Pool Spot. The study performed on a modified IEEE-30 bus test system shows that the en masse charging of EV will result in them not being 'price takers' anymore, instead influencing the day-ahead price for electricity. In turn, it also shows that advanced methods of controlled charging of EVs are necessary with their increased penetration level in order to maintain the market price at an acceptable level. Application of the first model to the Nordic market resulted in the market showing high resilience towards integration of EVs in the unconstrained case, with as high as 300% penetration when the system price is increased to the maximum value over the day.

Fixed Period Charging Model

The simplest form of scheduling of EV fleets can be performed by allowing them to charge their batteries during off-peak hours, when the demand and correspondingly the market price, is low. This is shown in Fig. 4.1 where the EVs charge their batteries during hours 1 to 6 when the conventional demand is low. The equally distributed charging of EVs and the effects of their increasing penetration level on the electricity market price is shown in Fig. 4.2. It can be observed that at higher penetration levels of EVs, the total load exceeds the peak of daily conventional load at hour 18.The result is that, more expensive generators are scheduled to satisfy the total load, because of which, the price of electricity increases drastically. This indicates that more advanced methods of control need to be used so that the battery charging of the EVs is scheduled in a way so as to reduce the impact on the price of electricity.

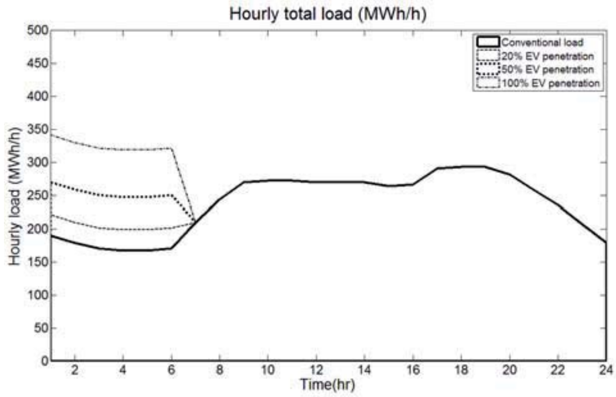

Figure 4.1: Daily load curve with the introduction of EVs

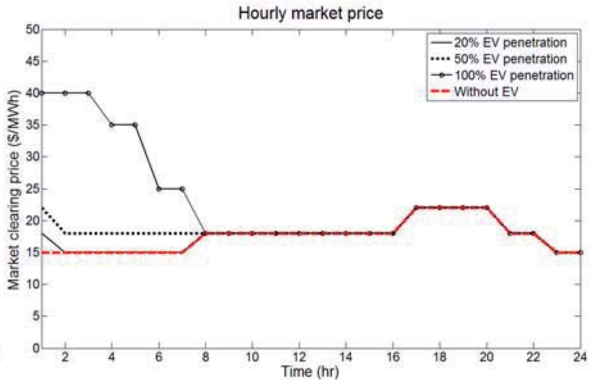

Figure 4.2: Hourly market price with the introduction of EVs

Joint Scheduling Model

In a scenario where advanced methods of communication and control is feasible, charging of EV fleets and generating sources can be scheduled simultaneously in a way so as to minimize the total cost incurred by the system, which is represented by the cost of generating electricity to supply the load over a period of 24 hours. The influence of such a controlled scheduling on the market price for 100% EV penetration in the IEEE test system is shown in Fig. 4.3 and 4.4. Comparing Fig. 4.2 and 4.4, it can be seen that with controlled scheduling of EV charging, the market price is increased to the maximum over the day hence, avoiding the situation where the price is artificially increased due to the limited amount of control available. Interesting to note is that no charging of EVs occurs during hour 24 because the optimization horizon of the problem is restricted to 24 hours and a constraint imposed which states that the EVs need to be charged before they travel.

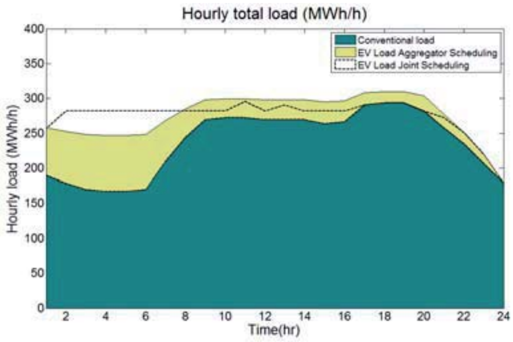

Figure 4.3: Daily load curve comparison at 100% EV penetration

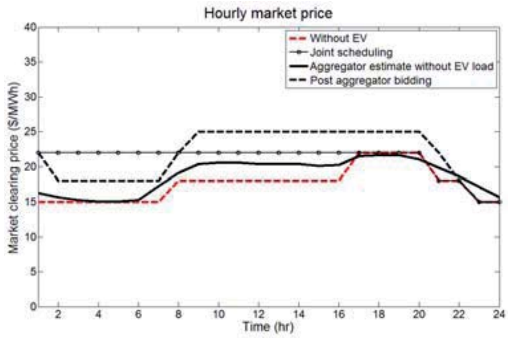

Figure 4.4: Market price comparison at 100% EV penetration

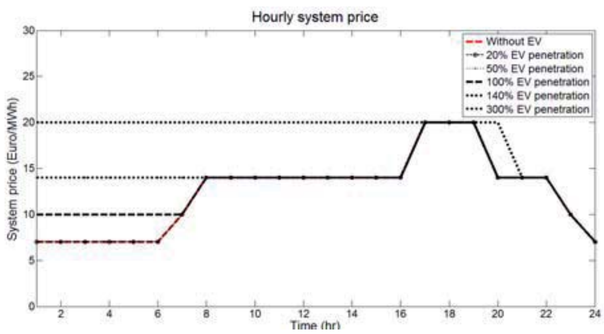

Figure 4.5: System price of Nordic market-Unconstrained case

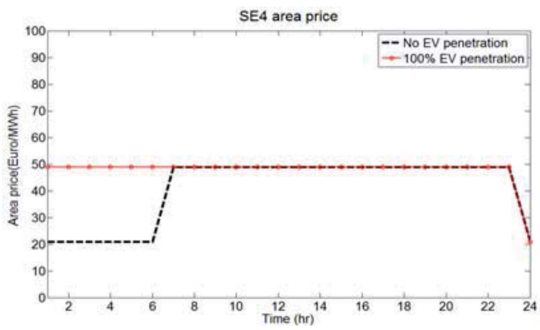

Figure 4.6: Area price of SE4 in Nordic market-Constrained case

NORDIC MARKET (PRELIMINARY) RESULTS

The Joint scheduling model applied to the Nordic market consisting of Norway, Sweden, Finland and Denmark assuming an unlimited amount of power exchange possibility between different bidding areas, shows that the Nordic market can accommodate EV integration levels of up to 300% before the system price increases to its maximum value over a period of 24 hours (Fig. 4.5). Whereas, for a constrained case with limited power exchange possibility between different bidding areas, the results shows that two areas namely SE4 and DK2 limit the increase in EV penetration to 100% at which the area prices attain the maximum value over the day (Fig. 4.6).

Aggregator Scheduling Model

In a scenario similar to the one described in the previous section, another model has been developed which is more representative of the Nordic day-ahead electricity market where the retailers represent individual customers in the market. The Aggregator agent schedules the charging of the EVs to minimize the total estimated charging cost. This charging schedule for a period of 24 hours is then submitted to the market which in turn dispatches the generators while minimizing the total system cost. The result of such a scheduling for 100% EV penetration in the system is shown in Fig. 4.3 and 4.4. It can be seen that the scheduling by the Aggregator agent results in a sub-optimal scheduling of EV fleet charging, thereby increasing the market price during certain hours. This can be accounted for by considering the error introduced in forecast of demand/price function, in which, the market price is considered to vary as a linear function of the total load (conventional load estimate by Aggregator is assumed to be perfect). A more accurate approximation using a higher order function will result in lower forecast errors. However, the complexity of the optimization model does not necessarily provide a solution.

Some concluding remarks

- Market integration of EVs might lead to an increase in market price at higher penetration levels, at which point advanced methods of control are necessary for scheduling EV fleet charging in order to limit the increase in market price for electricity.
- The goal of this study was to model the scheduling of EV fleet charging and observe the effects of the same on the market price. Changes in market price is also affected by a variety other factors such as conventional load profile, bidding strategies by various players, state of the generating units etc. and requires detailed statistical analysis to observe the effects of these factors on a particular system and derive conclusions.
- Transmission network constraints form an important limiting factor on the system level which can influence the actual flow of power, and hence, directly influence the penetration level of the EVs that can be accommodated in the system. A direct example of this can be observed in Fig. 4.6 where net transfer capacity (NTC) limits between different bidding areas was introduced. Apart from this, network constraints within an area also need to be introduced and the results analyzed.

Reference:
P. Balram, L. A. Tuan, L. Bertling Tjernberg, "Effects of Plug-in Electric Vehicle Charge Scheduling on the Day-ahead Electricity Market Price," Innovative Smart Grid Technologies Europe (ISGT), IEEE PES, Berlin, October 2012. Submitted for review.

4.9 Assessment of Electric Vehicle Charging Scenarios Based on Demographical Data

Plug-in Electric Vehicles (PEVs) are seen as one alternative to achieve a sustainable transport sector. However, a massive introduction of PEVs would likely increase the total electricity consumption and may increase the stress on the electrical power system. A recent research study presents an approach to evaluate the impact of PEVs charging on an electrical distribution system in terms of increased peak demand and capacity shortage. Additionally the study presents different methods to control the charging to reduce the peak demand.

The proposed approach

Figure 4.7 presents a flow chart of the approach proposed in D. Steen et. al. The approach can be divided into three parts. The first step is to gather the data needed for the study. From the data, three key parameters can be processed for further analysis: i) the locations of the vehicles (i.e., where can they be charged); ii) when they are parked (i.e. when can they be charged) and iii) technical limitations in the electrical distribution system. The second step is to formulate and implement the optimization models for different charge strategies. The final step is to use the data in the models developed to evaluate the impacts of different PEVs charge strategies on the electrical distribution system.

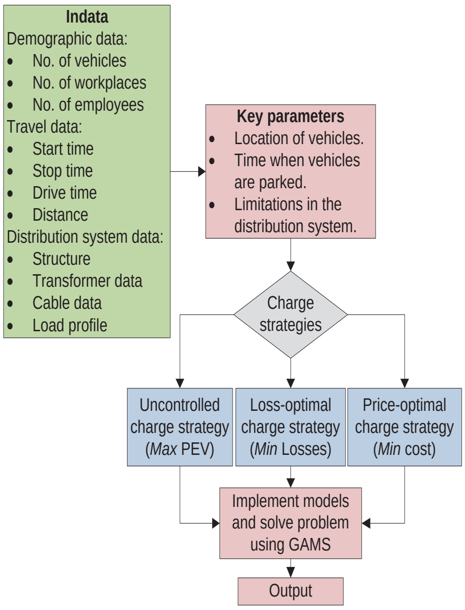

Figure 4.7: Flowchart of the proposed approach.

The models mentioned above are based on an AC optimal power flow framework which is described in e.g., K. Bhattacharya et. al., with the objective functions being: maximization of the number of PEVs, minimization of the losses in the electrical distribution system, minimization of the electricity cost paid by PEVs owners, respectively. These models were implemented in a General Algebraic Modeling System (GAMS), a high-level modeling system for mathematical programming and optimization.

Data and Assumptions

The study uses demographic data and a travel survey to assess the location and usage of the PEVs. The reason for using demographic data is due to that vehicles are used for transportation and may be charged at different locations during the day, if there is a well-developed charge infrastructure in place. The travel survey was used to assess the daily driving distance and the time when PEVs were parked.

A case study, using the proposed approach was conducted on two parts of the real electrical distribution system in Gothenburg, one commercial and one residential part. Additionally two different scenarios were simulated, i.e. charging only at home (scenario A) and charging both at home and at work (scenario B).

Figure 4.8 presents the stop time for commuting journeys, to work (VW) and from work (VH), and for all other journeys (VL), conducted by cars for both parts of the electrical distribution system analyzed in the case study. As can be seen, the number of vehicle is higher for the residential area compared to the commercial except for commuting journeys to work.

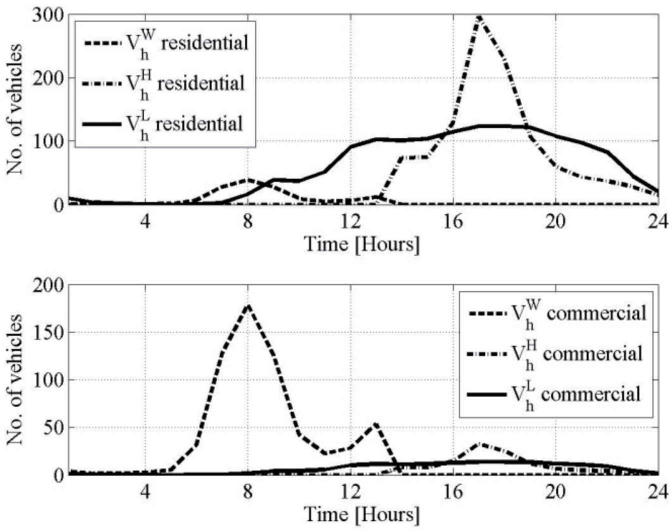

Figure 4.8: Stop time for different journeys for the simulated areas.

The study assumes that the customers in the simulated area have hourly electricity tariffs based on the spot price at Nordpool day-ahead market.

Results

Figure 4.9 presents the load profiles for the different control strategies for a full penetration of PEVs in the residential area. As can be seen, the peak demand would increase for both the uncontrolled and the price optimal control strategy. For the price-optimal strategy the charging takes place during the night but due to the high number of PEVs and since all PEVs start charging simultaneously this would result in a new peak. The loss-optimal strategy would charge the vehicles in such manner that the peak demand would not be increased.

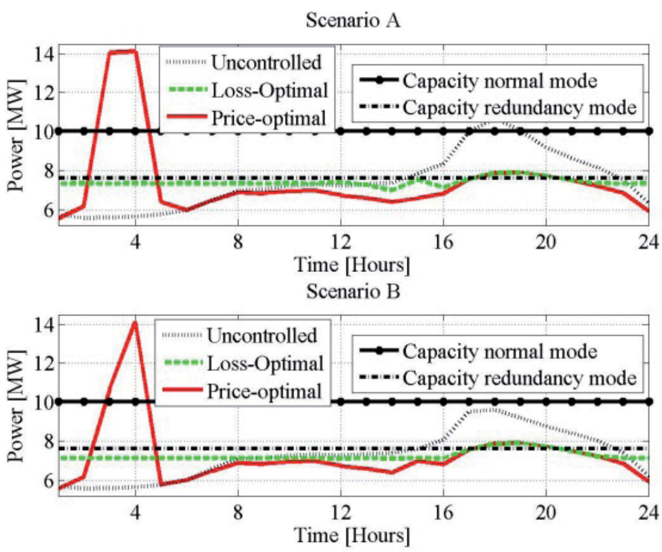

Figure 4.9: Residential load profile with a full penetration of PEVs

Figure 4.10 presents the load profile for a full penetration of PEVs in the commercial area. As can be seen, the impact would be less severe in the commercial part compared to the residential. This is due to the limited number of PEVs charging in this area but also due to that the initial conditions are less stressed. For the scenario allowing charging at work the impact would be more severe for the price-optimal strategy compared to the other two.

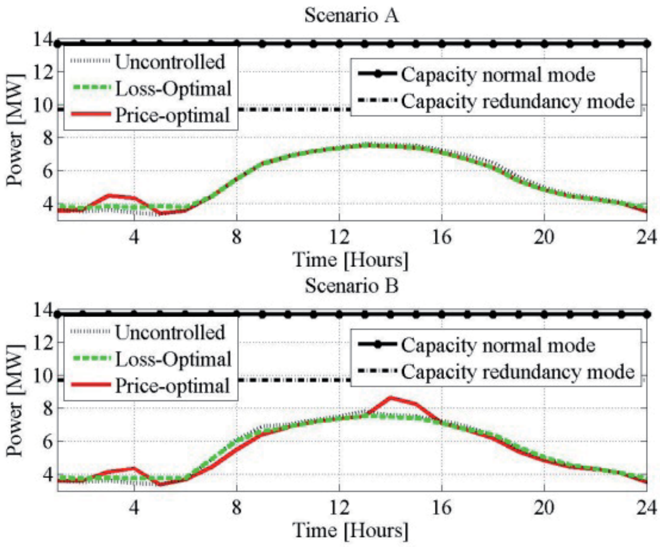

Figure 4.10: Commercial load profile with a full penetration of PEVs

As can be seen in Figure 4.9 and Figure 4.10 the impact varies much between the different areas, both due to the number of vehicles charging but also to the initial conditions in the electrical distribution system. The commercial area can withstand a full penetration of PEVs without causing any capacity problems in the electrical distribution system while, depending on the charge strategy, between 50% - 100% of the vehicles could be supported in the residential area.

The cost savings achieved by charging according to the price-optimal strategy was about 10-15%. However, the savings would vary for different days since the spot price at Nordpool varies.

The losses in the electrical distribution system were reduced by charging according to the loss-optimal strategy. The losses were reduced by about 4% of the total system losses, compared to the uncontrolled strategy.

However, the number of PEVs that could be supported was increased, indicating that the main advantage of the loss-optimal strategy was to reduce the need for reinforcement in the electrical distribution system.

References

D. Steen, T. Le, O. Carlson and L. Bertling, "Assessment of Electric Vehicle Charging Scenarios Based on Demographical Data." Accepted for publication in IEEE Transactions on Smart Grid Technology.

K. Bhattacharya, M. H. J. Bollen, and J. E. Daalder, "Operation of Restructured Power Systems", M. A. Pai, Ed. Kluwer Academic Publishers, 2001

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Chapter 4.1-4.5 and 4.7: Peter Fritz, Niclas Damsgaard, Sweco
Chapter 4.6: Håkan Sköldberg, Profu
Chapter 4.8: Pavan Balram, Tuan Le, Lina Bertling Tjernberg, Electric Power Engineering, Chalmers
Chapter 4.9: David Steen, Tuan Le, Lina Bertling Tjernberg, Electric Power Engineering, Chalmers

5. Evaluation of the challenges facing the change of the energy system

- a new method developed

The NEPP project has developed a methodology to evaluate the scenarios described above and generated synthesis-level results[1]. The methodology has been applied to the following sets of scenarios:

- The EU's Roadmap scenarios
- The NEPP scenarios for the development of the European and the Nordic electricity systems.

In what follows, we will briefly describe the evaluation methodology, and present results from the application of the methodology to the EU and NEPP scenarios.

The methodology is based on a simple scorecard-principle. Results from the methodology are therefore very illustrative – they are easy to understand and easy to present.

There have been discussions in the NEPP project to apply the methodology to new areas. An effort will be made during the autumn of 2012 to identify additional applications. Candidates include:
• Determine how challenging a scenario is, and what measures are required to reach the goals of the scenario. Possibly also estimate the likelihood that the goals can be reached, given a proposed set of measures.

- Estimate which policy instruments will be required to reach the goals of a scenario
- Estimate how the challenges associated with a scenario affect price levels in energy markets, carbon markets, and certificate markets.
- Compare challenges faced by historical restructuring with challenges associated with future scenarios.
- Compare scenarios for different geographical regions such as the EU, the Nordic region, or Sweden.
- Including different types of challenges: technology development, public acceptance, viability of a measure, security of supply, costs, etc.

5.1 The methodology

The methodology is based on the scorecard principle and groups challenges posed by the change of the energy system into three categories denoted by the colours green, yellow, and red. The colours have their usual meanings in that green represents challenges that are easy to overcome, yellow represents challenges that are somewhat harder to overcome, and red represents challenges that are difficult to overcome. In the methodology, challenges are evaluated in an "aggregated" manner by which challenges are assigned points, and are then classified as being green, yellow, or red. Figure 5.1 below shows how challenges can be evaluated using the methodology. The figure first appeared in the first presentation of the methodology in January 2012. During the spring of 2012, the level of detail in the evaluation has been refined, and an example from the transport sector will be shown below. The methodology is also being refined to take into account that challenges may vary over time, and that some challenges are additive.

However, we still evaluate challenges "on aggregate". Over time, the project intends to further refine the methodology so that it takes into account different indicators that identify different aspects of challenges. Such aspects may include technology and systems development, public acceptance, inertia, security of supply, market developments, and so on.

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[1] We bring together results and activities from parallel projects like Pathways, Elforsk's transport project, NETP and a scenario project together with the Confederation of Swedish Enterprise

However, we have currently no plans to incorporate "traditional" system development indicators such as costs in the methodology. The methodology will therefore generate scorecards that should be viewed as complements to evaluations based on traditional indicators such as costs, prices, energy consumption, energy intensity, emission levels, and so on. To what extent such indicators should be included in the methodology remains to be determined.

Red – Very significant challenges:

- Establishment of CCS and CO_2 infrastructure
- Share of wind and solar generation larger than 25%
- Very significant expansion of the electricity networks
- Very significant structural changes in industry and transport
- Very significant efficiency gains on the demand side.

Yellow – Significant challenges:

- New investment and upgrades in nuclear generation
- Share of wind and solar generation larger than 10-15%
- Significant structural changes in the industry and transport sec
- Significant efficiency gains on the demand side.

Figure 5.1: An example of how challenges can be evaluated using the methodology

An example of predominantly red challenges in the NEPP scorecard is challenges related to Carbon Capture and Storage (CCS). One of the greatest challenges facing the restructuring of the European energy system is whether and when Carbon Capture and Storage (CCS) will become viable. For in-stance, citing "insufficient will in German federal politics and lack of CCs legislation" Vattenfall recently cancelled a CCS demonstration project in Germany. Research conducted by Chalmers and others including NEPP, Pathways, and EU-JRC provides a very clear picture of the challenges associated with the establishment of CCS infrastructure (see Appendix 1).

An example of predominantly yellow challenges is challenges related to reserve capacity, for example an increased penetration of intermittency generation, and the expansion and reinforcement of the transmission grid. The second "sheet" in Appendix 1 describes how the EU grid model developed by NEPP reveals how small increases in energy flows cause severe transmission constraints on the German grid – for instance if exports from the Nordic region to Germany should increase.

The restructuring of the energy system will also require significant changes to the transport and the industry sectors – the associated challenges are difficult or very difficult. The third "sheet" in Appendix 1 shows that the energy intense industries in EU will find it very hard to make the necessary changes. In the transport sector, nearly all vehicles, and more or less the whole infrastructure must be replaced. Many of the underlying technologies are close to the point where they are commercially viable, but the challenges to completely transform the transport sector by 2050 are nevertheless huge. In the section below, the difficulties facing the transportation sector will be described in more detail. The section also serves to illustrate the principles for evaluating challenges that underlie the scorecard methodology.

5.2 An example – estimating challenges in restructuring the transport sector

This section describes the principles for evaluating the size of the challenges related to the restructuring of the transport sector. The same sets of principles, appropriately adjusted for sector-specific conditions, were used when the scorecard methodology was used to evaluate challenges in other sectors.

In the transport sector, the main goal is to reduce the use of fossil fuels and their associated emissions. All measures to reduce the use of fossil fuels belong to one of the following categories:

• Energy efficiency measures,
• Measures to reduce the need for transportation,
• Measures to replace fossil fuels by alternative fuels (biofuels or electricity)

Within each category, there are several measures to choose from, so the restructuring of the transport sector can be carried out in many different ways.

We now describe how the NEPP methodology can be used to evaluate the challenges. A number of different scenarios[2] for the Swedish transport sector are used as examples.

1. Measures to replace fossil fuels by alternative fuels dominate
The analysis is based on an assumption that measures to replace fossil fuels by alternative fuels will dominate the set of selected measures.
2. "Business as usual" determines maximal use of fossil fuels.
In the Business-As-Usual scenario (BAU) it was assumed that the transport sector would continue to rely on conventional technology and that historical trends in the demand for transportation would continue into the future. Based on these assumptions, the future needs of the transport sector were computed. In this scenario, the use of fossil fuels increases, and the scenario therefore serves as a reference scenario for the use of fossil fuels – see figure 5.2.

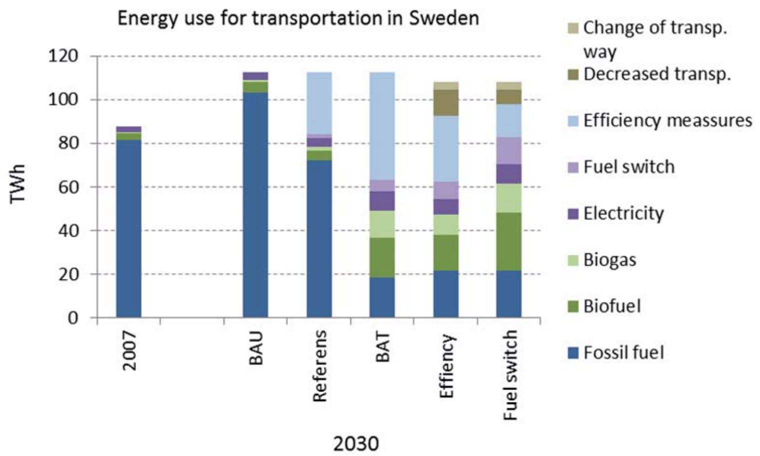

Figure 5.2: Energy demand in the transport sector in Sweden in the base year (2007), in the reference case (BAU) for the year 2030, and in three different scenarios for the year 2030

3. Determine scorecard: Evaluate challenges associated with different measures
Measures are evaluated based on the type of vehicle. As is evident from table 5.1, consumption from ordinary cars makes up the bulk of the energy consumption in the transport sector. In what follows, an evaluation of the challenges related to measures to increase efficiency in ordinary cars is described.

Table 5.1: Categorisation of the transport sector in scorecard development

Vehicle type	Energy use 2007, TWh
Personal cars	50,5
Motorcycles	1,2
Small trucks	8,5
Busses	2,6
Large trucks	17,9
Boats	1,6
Airplanes	2,4
Trains	3,4

[2] These scenarios are also used to model the development of the transport sector in the four main NEPP scenarios.

The estimation of how challenging it will be to increase the efficiency of ordinary cars is based on the EU emission standards. These state that in 2015, new cars may not emit more than 130 g CO_2/km, and the goal is that new cars should not emit more than 100 g CO_2/km by the year 2020. Today, the average car in Sweden emits 190 g CO_2/km, while new cars emit 150 g CO_2/km on average. It is likely that it will be too difficult for Sweden to reach the 2015 target. Furthermore, the average lifetime of cars is 15 years, which means that the effects of measures directed at new cars will be delayed. Based on these facts it is reasonable to assume that by the year 2030 the average car will emit 150 g CO_2/km, absent additional political initiatives. Compared to current levels, this is equivalent an increase in efficiency of 20 %. Since this outcome is “effortless” (no new legislation), we assign the measure to reach this particular level of increased efficiency the colour green.

Achieving emission levels below 150 g CO_2/km by the year 2030 is more difficult and measures to achieve this are therefore assigned the colour yellow. Finally, measures to achieve emission levels of 115 g CO_2/km or below by the year 2030 are assigned the colour red since reaching these levels is considered very difficult. A reduction of emissions down to 115 g CO_2/km represents an increase in efficiency of 39 %.

We have made similar estimates of the difficulties in reaching targets for other vehicle types and other types of measures. These estimates form the basis for the scorecard for the transport sector. Using these values, it becomes possible to construct scenario specific scorecards that contain estimates for those measures that are included in specific scenarios. For instance, Table 5.2 shows the scorecard for a scenario we have named “Efficiency”.

Table 5.2: Scorecard for the Swedish transport sector in the Efficiency scenario

Quantities (TWh)	2030
Green level of efficiency	<18
Yellow level of efficiency	18-34
Red level of efficiency	>34
Green level of transportation decrease	<2
Yellow level of transportation decrease	2-10
Red level of transportation decrease	>10
Green level of biofuel	<9
Yellow level of biofuel	9-20
Red level of biofuel	>20
Green level of electricity	<4,4
Yellow level of electricity	4,4 -6,4
Red level of electricity	>6,4

Use the scorecards for the different scenarios

Figure 5.3 below shows the outcomes for the three different scenarios. In this particular case, the scorecards have been used to illustrate how energy use differs between the different scenarios, but the scorecards can also be used to illustrate other effects. For instance, the scorecards could be used to illustrate how carbon emissions vary across different scenarios.

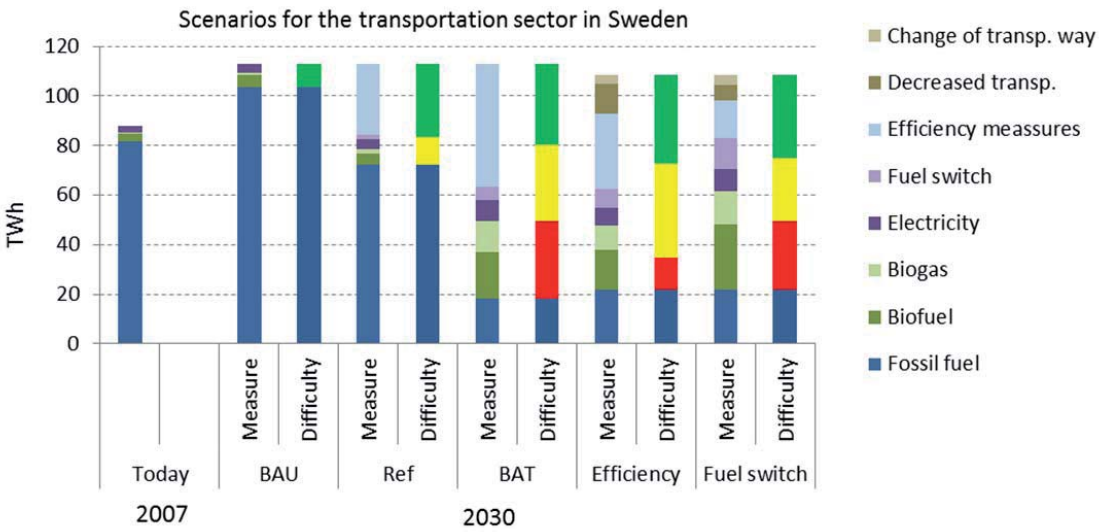

Figure 5.3: Challenges related to the restructuring of the transport sector – three different scenarios

5.3 The application of the methodology to the EU Roadmap scenarios

The EU's "Energy Roadmap 2050" contains 10-15 different scenarios. During our analysis of these scenarios, we also included the earlier "Baseline 2007" scenario to be used as a reference scenario to compare the other scenarios against. The "Baseline 2007" scenario is the base scenario that the EU is using in its work to formulate the 20 % energy efficiency goals included the upcoming Energy Efficiency Directive.

THE SCENARIOS CAN BE GROUPED AS FOLLOWS:

1. **Baseline 2007**
2. **Reference:** The EU Energy Roadmap 2050 contains several reference scenarios and one scenario called "Current Policy". All of these are reasonably similar, and have for this reason been grouped under the name "Reference" in our analysis.
3. **Roadmaps:** The EU Energy Roadmap 2050 contains several scenarios in which carbon emissions are reduced significantly by the year 2050. The overall emission levels are more or less the same in all scenarios – the differences lie mainly in the chosen energy sources and technology. In this report, we have chosen to focus on the following two scenarios:
   a. **Diversified Supply Technology:** This scenario is very similar to the NEPP scenario called "Climate Market". In both of these scenarios, the restructuring of the energy system is largely driven by an ever-higher carbon price.
   b. **High Renewable Scenario:** In this scenario, the restructuring of the energy system is mainly driven by a massive rollout of renewable energy generation. This scenario resembles the NEPP scenario called "Green Policy", the difference being that the NEPP scenario includes energy efficiency measures, which are absent from the EU scenario. In the EU Roadmap, energy efficiency measures are instead included in a special scenario devoted to energy efficiency.

In a first test of the scorecard methodology, the methodology was applied to the two EU Energy Roadmap 2050 scenarios ”Diversified Supply Technology” and ”High Renewable”. The results are shown in the two wedge-diagrams below. In the diagrams, emissions reduction measures have been given the colours red, yellow, or green, based on their assigned values in the scorecard.

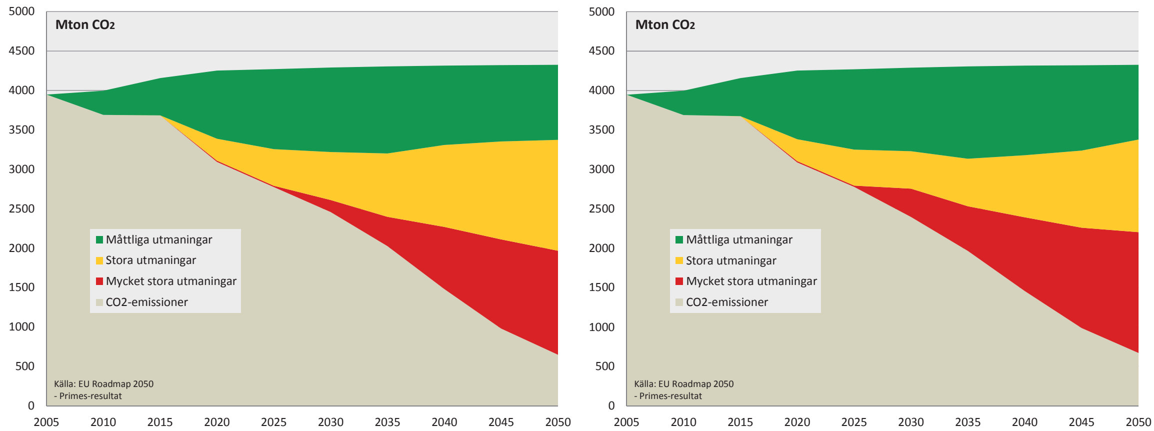

Figure 5.4: Reduction in carbon emissions according to the Scorecard, in the Diversified supply technologies scenario. Modest challenges (green), Significant challenges (yellow), Very significant challenges (red).

The figures show that two thirds of the measures face challenges that are great or very great. The figures also show that the level of difficulty is the same for both scenarios, even though they are based on different sets of measures. This is a very interested outcome, and if further analysis proves that it is correct, an indication that the scorecard methodology can yield results that would otherwise be very hard to find.

Comparison with carbon prices

One natural measure of the difficulties in reducing carbon emissions is the carbon price. All EU Energy Roadmap 2050 scenarios contain information about expected carbon prices. The carbon prices for the two Roadmap scenarios selected by NEPP for closer analysis are shown below:

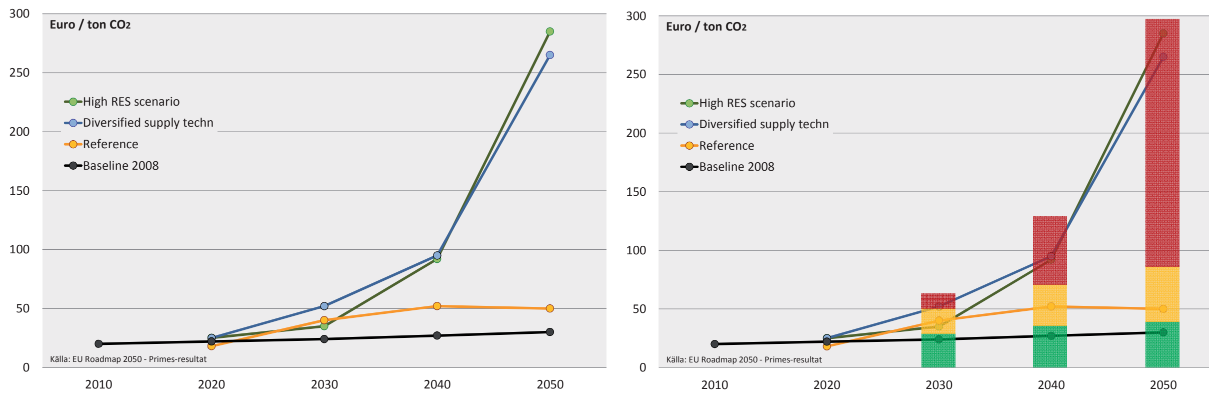

Figure 5.5: CO_2 prices in the EU-27 – according to the EU Energy Roadmap 2050s (left). CO_2 prices in the EU-27 – according to the EU Energy Roadmap 2050s, in comparison with schematic scorecard bars (right).

A comparison of these carbon prices with the challenges associated with different measures as derived by the scorecard methodology yields figures such as the one shown below:

This comparison is very illustrative. When carbon prices reach 250 EUR/tCO_2, it is obvious that the challenges are huge. Furthermore, the results from the Roadmap show that carbon prices are equally high in both scenarios, which confirms the scorecard findings presented above.

Electricity production in the EU Energy Roadmap 2050 scenarios

We have also used the scorecard methodology to evaluate the challenges posed by the restructuring of electricity production in the two Roadmap scenarios we have selected. In the figure below, the results are presented in terms of energy (TWh). Again, the scorecard method shows that the magnitude of the difficulties faced in the two scenarios is very similar, even though the set of measures in the two scenarios are very different (total electricity production in both scenarios is more or less equal)

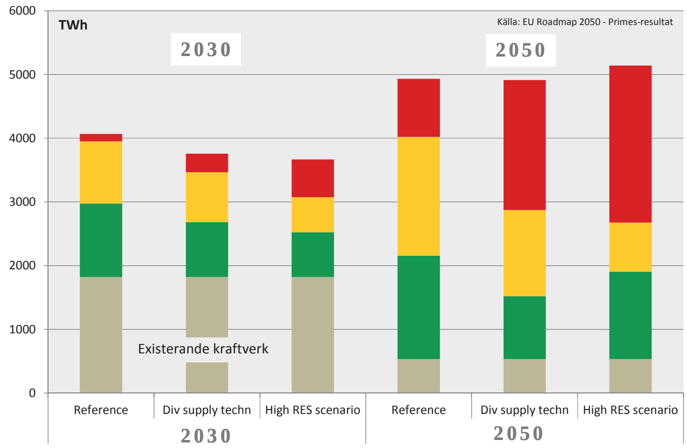

Figure 5.6: Electricity generation in the EU-27 – according to the Scorecard. Existing units in grey.

NB: Electricity generation in the scenarios is of course based on several different generating technologies (nuclear, natural gas, coal, renewable), even though this is not shown in the figure above. The figure only shows how large the challenges are. In Chapter 3 above, the generation mix is described in greater detail (for the NEPP scenarios).

To illustrate differences for different generation mixes, we have below visualized the scorecards based on capacity (GW). This clearly shows the effect of additional renewable generation in the "High Renewable" scenario.

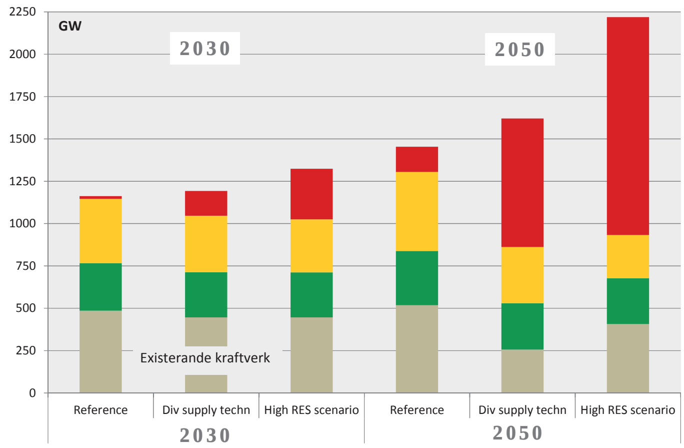

Figure 5.7: Electricity generation capacity (GW) in the EU-27 – according to the Scorecard. Existing units in grey.

5.4 Comparing with history – Swedish decline in oil use since the 1970s

Another way to ”calibrate” a new method is to apply the method to analyse historical data, as we already know the outcome and can learn from it. We have chosen to look at the decline in oil consumption that took place in Sweden over the period stretching from the 1970s to roughly the beginning of this century, or maybe stretching as far as today.

We have only studied the stationary energy sector as the transport sector's restructuring is still in early days. If we plot the reduction in the share of oil in total energy consumption in the stationary energy sector we get the following diagram:

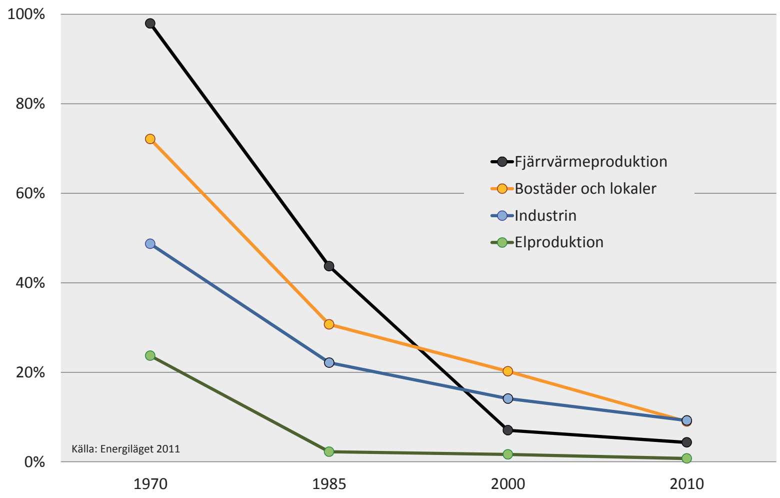

Figure 5.8: Reduction in oil consumption in Sweden. Share of oil in total energy consumption in the energy sector (excluding transport). District heating (black), Buildings (orange), industry (blue) and electricity production (green).

District heating was almost completely oil-based in the 1970s, and it was not alone. However, oil's share in electricity generation was only about 25%, as hydropower was the dominant generation resource in the 1970s.

In the figure below, we have put a value to this reduction in demand for oil. We have done this using the same scorecard that we have used for the EU Energy Roadmap 2050 scenarios. Our scorecard shows that the introduction of nuclear power is the only development in the Swedish energy transformation that can be classified as yellow (we have classified all generation increases after 1981 when the nuclear referendum took place as "yellow", and other generation as "existing"). Every single other changeover in the Swedish energy system has been green. If we remember the energy debate during this time, we also remember that it was very one-sided and pro-nuclear, which can be taken as an indication that out method can trace the biggest challenges.

But it gets even more interesting when we compare the Swedish radical change of the past 40 years (1970-2010) with the EU's planned roadmaps for the coming 40 years (2010-2050). In the figure below we show carbon reductions for the EU scenario "Diversified Supply Technology", but we have also included the levels of carbon emissions under the EU's reference scenarios (as a dotted line). A quick comparison between the two diagrams below shows that our historical transformation has approximately the same "degree of challenge" as EU's reference case.

If we remember from previous sections that the price of carbon in the EU's reference case is approximately 40-50 EUR/tCO_2 and that out carbon tax (as an average over time and over sectors) has been of roughly the same size, we can conclude that even a transformation (in the EU) equivalent to that under the reference case is a significant challenge. To go even further than the reference case would require an effort of a significantly larger magnitude than the effort invested in Sweden since the 1970s to reduce oil consumption.

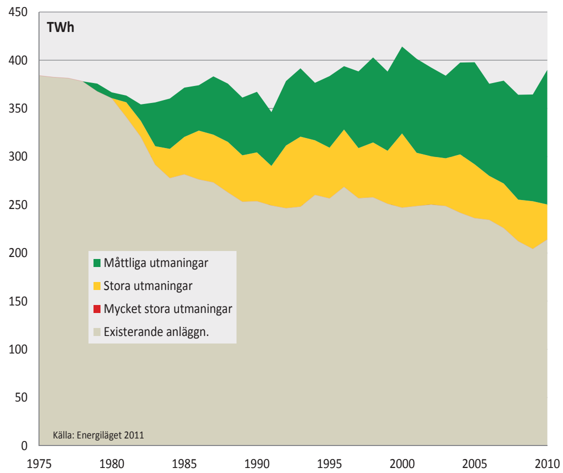

Figure 5.9: Reduction in oil consumption in Sweden according to the Scorecard. Modest challenges (green), Significant challenges (yellow), Very significant challenges (red).

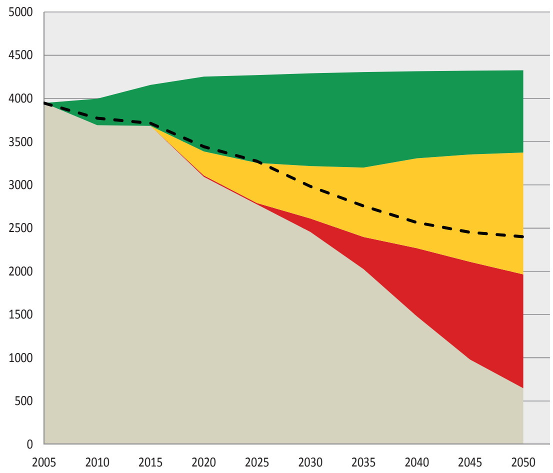

Figure 5.10: Reduction in carbon emissions in the EU-27 according to the Scorecard, in the Diversified supply technologies scenario. Modest challenges (green), Significant challenges (yellow), Very significant challenges (red).

The two scenarios from the study ”Sun and Uranium”

During the 1970s, several future studies were undertaken in Sweden, but few had such a drastic change of the energy system as a starting point as the EU's Roadmap scenarios do. However, the book “Sun and Uranium” published by the Swedish Institute for Future Studies in 1979 contains two scenarios that describe a very radical transformation of the energy system over the period 1975-2015: a “sun scenario” and a “uranium scenario”. In the “sun scenario”, renewable resources supply all energy, while in the “uranium scenario” almost all energy is derived from uranium: 67 nuclear condensing units, 6 nuclear-powered CHP and 10 heating plants.

If we use our scorecard and evaluate the challenges under these two scenarios, we will - at least in the ”Sun scenario” - get a result similar to those for the EU Roadmap scenarios.

However, the result does not yet constitute grounds for scientific “benchmarking” but we consider the similarities between the scenarios thought out in the 1970s and today's scenarios to be of interest. We will study these results further in the second half of the project.

5.5 The first tentative conclusions – and a theory on policy instruments

If we summarize our impressions of our scorecard methodology to date, we can formulate our first tentative conclusions:

- The radical change of the EU's energy system will pose to major challenges!
- These challenges are equally significant, regardless of the Roadmap.
- The challenges posed by the 2010-2050 roadmap of the EU energy system are more significant than those faced by Sweden during the 1970-2010 drive for oil reduction.

We will also point out that our scorecard can help us gain insight into how policy instruments to aid the restructuring of the energy system will be designed (if the restructuring is carried out in full).

A theory we are putting forth – and that will be developed during the remaining half of the NEPP project – is that our conventional policy instruments will be able to deliver the green and (maybe even half of) the yellow measures, but that (the remaining) yellow measures and red measures will require further political intervention. CCS is an example of a red measure. We are of the opinion that, without further support, the necessary investment in carbon storage infrastructure will not take place.

We believe that in the future, our scorecard can help us to reach conclusions similar in nature to:

- A considerable share of the restructuring will require strong political involvement, and very tough and powerful policy instruments.
- Financial policy instruments and other conventional policy instruments, are not enough!

5.6 Applying the scorecard method to NEPP's four scenarios for the Nordic electricity system

We have also applied our scorecard method to our four NEPP scenarios for the Nordic electricity system that we have presented in chapter 3 above.

Carbon reductions and electricity production

The figure below shows the scorecard for carbon reductions in the Nordic region. The result is similar to the one obtained for the EU's Energy Roadmap 2050. An important difference is that the transport sector weighs more in the Nordic diagram than in the European diagram. We can also see that the stationary sectors - including the electricity sector – have red challenges ahead.

The scorecard for electricity production in the Nordic region for all four NEPP scenarios is shown below.

The challenges facing electricity production in Sweden are roughly of the same size as the challenges facing the Nordic region as a whole. Nuclear power accounts for the biggest difference in results, as nuclear power plays a more predominant role in Sweden than in the rest of the region. All other differences are small.

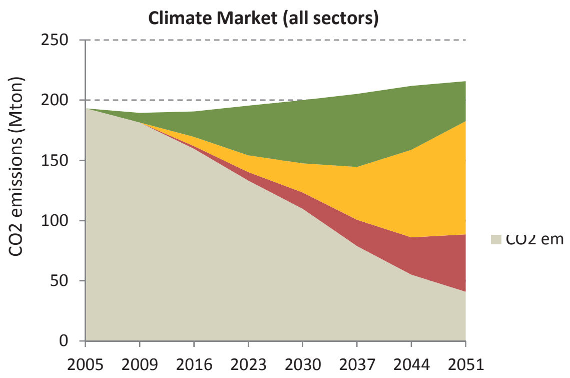

Figure 5.11: Reduction in carbon emissions in the Nordic countries according to the Scorecard, in the Climate Market and Green Policy scenarios. Modest challenges (green), Significant challenges (yellow), Very significant challenges (red).

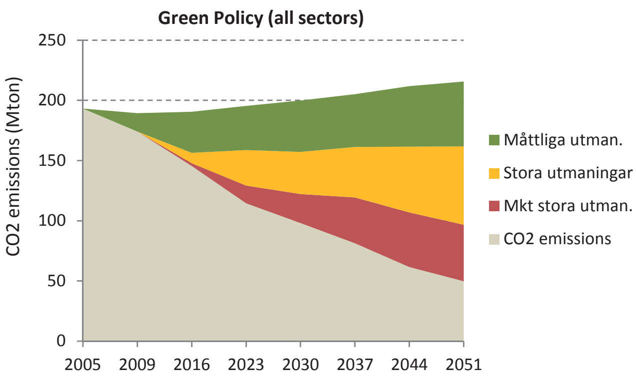

Figure 5.12: Reduction in carbon emissions in the Nordic countries according to the Scorecard, in the Climate Market and Green Policy scenarios. Modest challenges (green), Significant challenges (yellow), Very significant challenges (red).

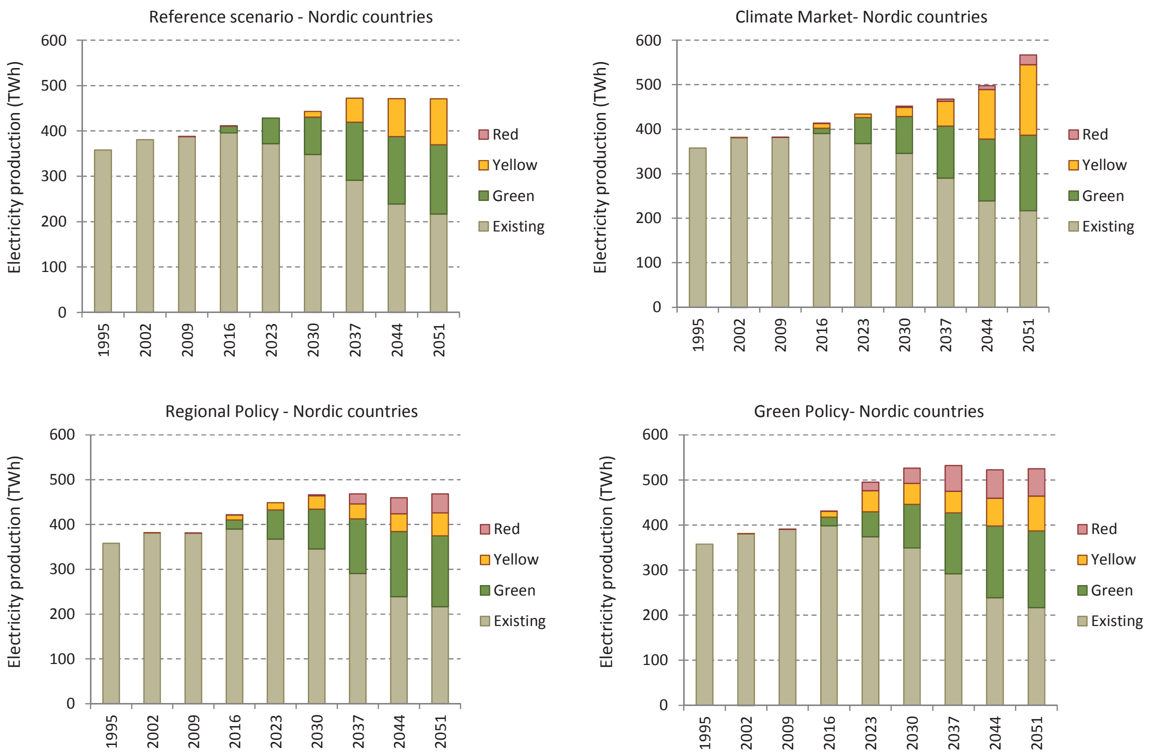

Figure 5.13: Electricity production in the Nordic countries according to the Scorecard, in all four NEPP scenarios. Modest challenges (green), Significant challenges (yellow), Very significant challenges (red).

For more information:
Bo Rydén, Profu

6. In short

In this chapter we present short descriptions of ongoing work.

6.1 Measures in the energy system that reduce non-CO_2 greenhouse gases

IVL will analyze which measures, connected to the energy system, affect the emissions of other greenhouse gases (GHG) than CO_2 and to what extent. The GHGs being analyzed include methane, nitrous oxide (N_2O), and fluorinated greenhouse gases, but also ozone and short-lived climate forces (SLCF). The measures identified so far are presented in Table 6.1.

Table 6.1. Measures connected to the energy system affecting emissions of other GHGs than CO_2.

Methane	Nitrous oxide	Others
• Incineration of biodegradable solid waste instead of disposal at landfills • Reduction of leakage of methane at coal mines and gas and oil production sites • Increased control of fugitive methane emissions from gas distribution systems • Measures to reduce incomplete combustion of fuels • Drainage of peat land	• Combustion modifications in fluidised beds • Consideration of N2O-emissions related to biomass/biofuels (direct and indirect) • Modifications of vehicle catalysts • Avoid drainage of peat land	• Reduce leakage of cooling agents (hydrofluorocarbons - HFC) from heat pumps • Measures to reduce sulphur hexaflouride (SF6) from high-voltage circuit breakers and switchgears • Modifications of air-conditioning plants in vehicles (fluorinated greenhouse gases)

For each measure, based on existing literature and other references, the magnitude of the associated emissions will be analyzed (as kg CO_2 equivalents per energy unit). The information will be compiled in order to assess which measures that have small respectively large impact. To the extent possible and when relevant, the potential for reducing the emissions in the future will also be described. The synthesis will to a large extent be based on data compiled by IVL for Sweden´s international reporting of greenhouse gas emissions (in the scope of SMED: Svenska miljöemissionsdata). One example of how the measures are analyzed is given in the following section.

Leakage of refrigerants (fluorinated GHGs) from heat pumps and air-conditioning plants in vehicles

Fluorinated GHGs include HFC, PFC and SF6 gases. In 2010 the emissions of fluorinated GHGs amounted to 1 million ton of CO_2 equivalents (CO_2e) which correspond to 2 % of the total direct GHG emissions in Sweden. The largest sources of emissions from refrigerants in Sweden are mobile air-conditioning systems (460 ktons CO_2e/year) and emissions from heat pumps (mainly HFC) (21 ktons CO_2e/year). With the approximately 1 million heat pumps in Sweden delivering about 20 TWh of heat this corresponds to about 1 g CO_2e/kWh delivered heat.

A new European directive (2006/40/EG) restricts the use of refrigerants which have a higher GWP factor than 500. Projections from SMED[1] assume that the fluorinated GHG emissions from mobile AC systems will decrease from 463 to 27 ktons CO_2e from 2009 to 2030 (due to the use of new refrigerants with lower GWP factors). Thus, the potential for reducing emissions of fluorinated GHGs from heat pumps is large.

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[1] *www.smed.se /luft/projekt-och-utredningar/pagaende-projekt/1986*

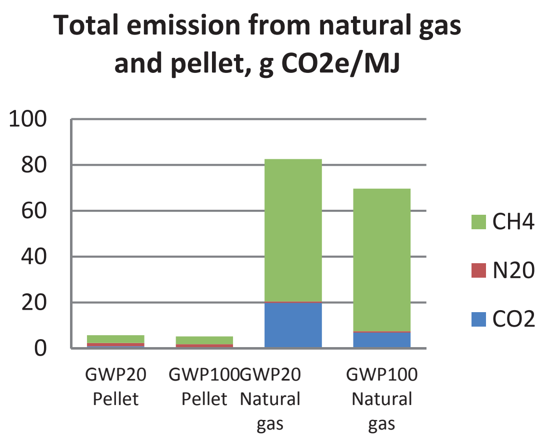
Emission factors of greenhouse gases from fuels and energy carriers

IVL will also compile emission factors for different fuels and energy sources in a life-cycle perspective, i.e. taking into account emissions from extraction, transport and refining of fuels (upstream emissions) and emissions from combustion of the fuel (downstream emissions). The upstream and downstream emissions will be presented separately to visualize where in the life-cycle the majority of the emissions occur and to facilitate integration of data into the energy system models used in NEPP. This section of the project will also discuss and elaborate on Global Warming Potentials (GWP) and their importance in describing climate impacts from fuels and energy carriers. Global warming potential, GWP, is used to compare different GHGs. The GWP describes the ability for a GHG to contribute to global warming. It is measured by the mass of CO_2 corresponding to an equivalent contribution, by any other substance, to the global warming.

GWP is calculated for a specific time interval which commonly is 20, 100 and 500 years and for different time intervals the total emission for fuels will change. As an example, Table 2 shows different values of GWP in two different time perspectives (20 and 100 years) for some greenhouse gases (according to IPCC).

	20 year GWP	100 year GWP
CO_2	1	1
CH_4	72	25
N_2O	289	298

To illustrate the importance of which GWP that is used, Figure 6.1 shows the total GHG emissions from 1 MJ natural gas and pellets with the 20- respectively the 100-year-perspctive (GWP20 and GWP100). The total emissions increase by about 10 % for pellets when 20 years GWP is used instead of 100 years GWP, whereas for natural gas the contribution increases by 18 %. Figure 6.1 (on the right) also shows that with a longer time perspective the contribution from methane is reduced.



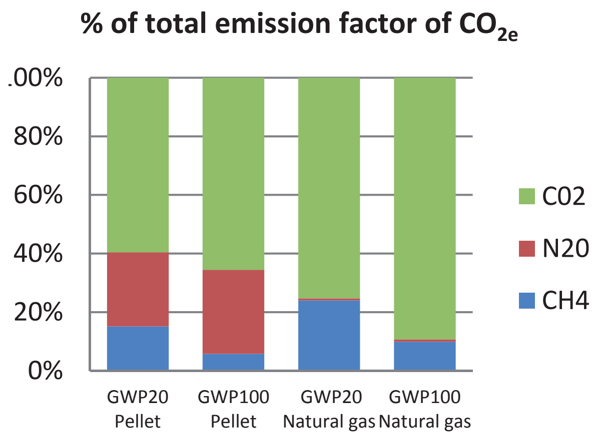
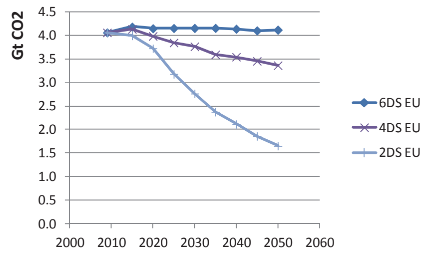


Figure 6.1: The importance of time perspective when calculating climate impacts of fuels. Example illustrating emission factors in g/MJ fuel (left) and percentage of emission factors (right) for pellets and natural gas.

6.2 The climate targets in the Nordic region (and the EU) are more far-reaching than those specified by IEA in ETP 2012



NEPP is the Swedish partner in the IEA project to develop a Nordic ETP – a Nordic subproject of the IEA global project called ”Energy Technology Perspectives”. This cooperation between NEPP and IEA gives NEPP an opportunity to participate in the analysis and modelling work performed by the IEA, and provides NEPP with insights into how the IEA reasons and what basic data they have access to.

The main scenario in the global ETP is a “two degrees scenario” where by 2050 global emissions are reduced by 50 % compared to 2009 levels. The IEA uses its models to compute how this reduction must be distributed among the countries and regions of the world. The IEA also computes the carbon price – from a global perspective – that is associated with this reduction. In the main scenario, the carbon price rises and reaches 110-120 EUR/tonneCO_2 by the year 2050.

ETP 2012 shows that the EU and the Nordic region “only” have to reduce carbon emissions by 60 % by the year 2050

For the EU, IEA calculations point to carbon emissions that in the year 2050 are 60 % lower than in 2009. These levels, and the associated carbon price, are compatible with those presented in the EU Energy Roadmap – the EU believes that with a carbon price of 110-120 EUR/tonneCO_2, emissions will be reduced by 60 % over the period 2009-2050. However, the main scenario in the Roadmap is about an 85 % reduction in greenhouse gas emissions, with a significantly higher carbon price of 250-300 EUR/tonneCO_2.

For the Nordic region, IEA foresees in its main scenario that greenhouse gas emissions will be reduced by 60 % between 2009 and 2050. It should be noted that this reduction is much lower than current national targets. For instance Sweden has a climate goal that states that “Sweden should not have any net greenhouse gas emissions by the year 2050”.

According to the IEA, this difference in the target levels is based on a difference in how the global target is allocated among countries and regions. The IEA allocates less of the total target to the EU than the EU itself does.

6.3 The EU may fail to reach its 2020 renewables target

At present, the official line from the EU and Member States is that the EU will reach its targets to reduce greenhouse gas emissions by 20 % and increase its share of renewables to 20 % by the year 2020. The national Progress Reports on the promotion and use of energy from renewable sources and describing the Member States’ progress in increasing their use of renewable energy show that the renewable sub-targets for the year 2010 were reached. Emissions reduction progress reports were also positive. However, analyses performed by NEPP show that the optimism about the renewables target might be misplaced.

NEPP believes that it is far from certain that the EU will reach its 20 % renewables target by the year 2020. This belief does not stem from scepticism over the renewable energy National Action Plans. It is based on the belief that Member States will not be able to reduce growth of overall energy demand sufficiently to reach the goal. The renewables target is a relative target – the amount of renewable energy production divided by the total use of energy (expressed as final energy).

Several Member States have assumed that they will be successful in reducing growth in energy demand. As a consequence of the financial crisis of 2008 and the current financial turmoil in the eurozone, energy demand growth has slowed, allowing Member States to reach partial targets for renewable use. But it is far from clear that Member States will be able to keep energy demand at these low levels once the financial turmoil subsides. So far only data for a few years is available for analysis. However, developments in the period 2008-2010 give some indications about what may lie ahead. NEPP has analysed energy use and economic development during the 2008-2010 period in several Member States including France, the UK, and the Netherlands, and has found that these countries have not been able to break the connection between economic growth and growth in energy demand. As soon as their economies showed signs of recovery, energy demand rose, and energy demand growth seems to be directly proportional to GDP growth. If energy demand continues to grow with GDP all the way to 2020, these countries will not be able to reach their renewables targets, which will in turn endanger the EU-wide target.

The energy efficiency directive may contribute to goal fulfilment for the renewables target

A new Energy Efficiency Directive is currently being debated in the EU. NEPP intends to perform an analysis of the likely consequences of the Directive once a final proposal becomes available. We will therefore not present an analysis of the Directive in this report.

However, given our analysis of the link between total energy demand and fulfilment of the renewables target, we believe that a new Energy Efficiency Directive may contribute to the fulfilment of the renewables target. It may even be necessary to have a more robust Energy Efficiency Directive in place for the EU to reach its renewables target.

The reserve capacity problem

The Renewables Directive mandates levels of renewable energy use, but does not say anything about reserve capacity to counterbalance renewable intermittency. Member States that plan to introduce wind and solar power on a large scale must make sure that it is possible to actually use all this new capacity – otherwise it will not yield the desired renewable energy.

Analyses conducted by NEPP point to several factors that may limit usage of wind and solar power:

- Transmission grid constraints may make it difficult to transport the electricity generated to consumers. The transmission grids in the EU are already congested, and it is unclear if it is possible to expand transmission grids fast enough to meet the requirements placed by both normal growth in demand and by the introduction of large-scale wind and solar power.
- Aggregate forecasting of wind generation offers a TSO the ability to handle higher wind penetrations, particularly on weaker grids, more securely. However, it is not always possible to place wind generation at locations that facilitate the aggregation of wind farms for forecasting purposes.

In the next phase NEPP will refine the analysis of the capacity problem.

For more information:

Chapter 6.1 and Statement no.12: Lars Zetterberg, Julia Hansson, Jenny Gode, IVL
Chapter 6.2 - 6.3: Bo Rydén, Profu

Appendix 1:
Three NEPP synthesis sheets

EUROPEAN pathways

jointly with

NEPP north european power perspectives

Results

March 2012

Linking techno-economic modeling of Europe's electricity sector to large-scale CCS infrastructure optimization

The following preliminary conclusions can be drawn of the research that has been done so far:

- **Even though being both considerably more expensive and requiring larger systems than onshore storage, offshore storage is the most likely alternative when storing large quantities of CO_2.**
- **Onshore storage of large quantities of CO_2 is associated with substantial difficulties, and is therefore considered unlikely to be realized. This is due to export dependency to a few, very large aquifers in densely populated areas, such as the Paris basin, where both storage capacity and annual injection capacity is highly uncertain, but also on the acceptance among the public and need of pressure reduction due to water production.**
- **The quantity of CO_2 that needs to be stored according to Pathways' Market scenario (for the period up to 2050) is too large to be contained in those offshore sinks that have been identified in the joint research project of CTH and JRC. This is true given the conditions of this project, i.e. use of the conservative theoretical storage capacity value that was estimated in the GeoCapacity project, and a minimum of 45 years injection time in the aquifers.**
- **The same identified sinks are however able to contain the quantity of CO_2 that needs to be stored according to Pathways' Policy scenario.**

The on-going collaboration with the EU Commissions Joint Research Centre (JRC) on large-scale CCS links annual CO_2-flow by country provided by Chalmers ELIN model to a model developed by JRC optimizing a bulk CO_2-pipeline network. The bulk system provided by JRC is thereafter developed into a detailed CCS network with collection and distribution pipelines with use of Chalmers databases on CO_2-sources and sinks. The on-going work develops a CCS system transporting 15.2 Gt CO_2 between 2020 and 2050 as provided by Chalmers Policy scenario. JRC's work indicates significant increases in cost moving from onshore to offshore storage with investments for a bulk system alone more than doubling from € 14 billion to € 29 billion. Chalmers work shows that cost are rising substantially also when the bulk system is developed further into a detailed network of collection and distribution pipelines with total investments for the German system alone reaching € 9.3 billion in the case of onshore storage. Still, specific cost is modest, e.g. calculated to € 5.1/ton CO_2 in Germany. The introduction of a minimum injection period of 45 years in aquifers forces large volumes of CO_2 to be exported to France and Poland indicating that large-scale CCS in Europe will only be possible if substantial part of the CO_2 is stored offshore.

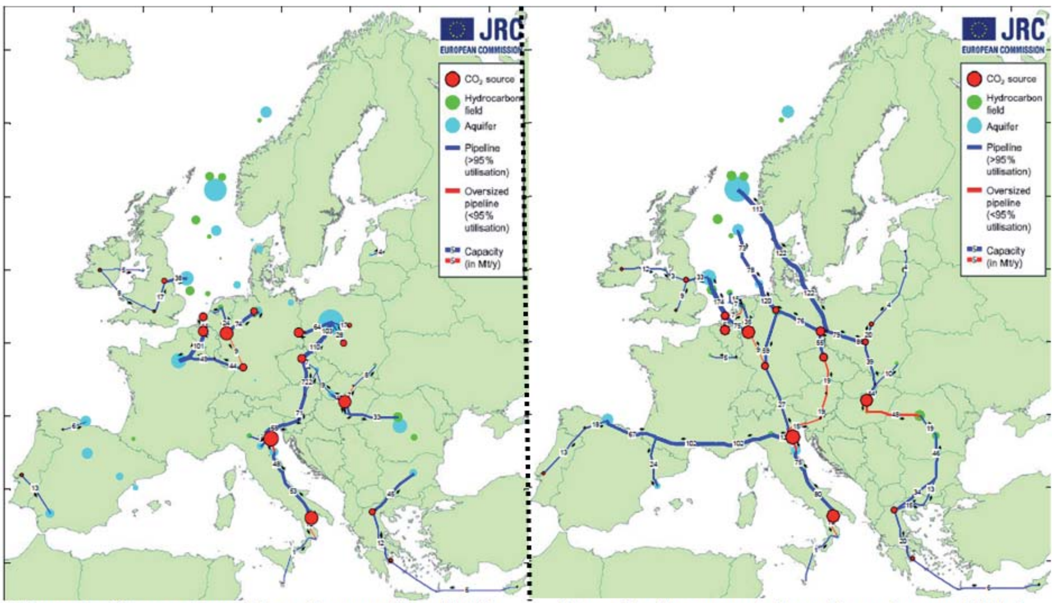


Figure 1a : Storage allowed in onshore aquifiers. Total investments € 14.0 bl, total network length 10,430 km.

Figure 1b : Storage <u>not</u> allowed in onshore aqf. Total investments € 29.1 bl, total network length 15,200 km.

Offshore storage will add significantly to cost

Figure 1 shows JRC's bulk pipeline system in 2050 based on the Policy scenario with Figures 1a and 1b illustrating a case where storage in onshore aquifers is and is not allowed respectively. Onshore storage is allowed in oil and gas fields in both cases since these have proved to be closed reservoirs. The system is based on clustering of sources and sinks (red circles denote cluster of sources, blue denote cluster of aquifers while green denotes cluster of oil/gas fields) with JRC applying the conservative storage capacity given by the GeoCapacity project. In total some 15.2 Gt CO_2 is transported to storage sites between 2020 and 2050 as envisaged by the Policy scenario.

Designing a detailed network requires accurate geographical information

Ongoing work applies the information provided by Figure 1 along with Chalmers databases on power plants and CO_2 storage sites to develop a detailed collection and distribution system. The geographical distribution of CCS plants is done by applying the information provided by ELIN's Policy scenario to replace existing plants according to age. Part 3 has restarted its work several times since initial very sparse information about storage sites in Germany, Italy and Poland have been replaced by more detailed data. Figure 2a shows how Chalmers initially envisioned distribution of aquifers in Germany based on communications with Vattenfall and the German Bundesamt für Geowissenschaften und Rohstoffe (BGR) while Figure 2b shows the actual distribution as provided by Greenpeace based on work performed by BGR. The black dots and lines in Figure 2a shows CCS plants and distribution pipelines respectively while red circles show large gas fields and light yellow circles denote aquifers. Each aquifer was assumed to have a storage capacity of 100 Mt CO_2 with a combined storage capacity corresponding to the conservative estimate provided by GeoCapacity (6.3 Gt). In Figure 2b, aquifers are shown as green circles with size depending on storage capacity and where the largest aquifers are able to store around 300 Mt if a conservative approach is being applied, i.e. 6.3 Gt aggregated for all German aquifers.

The collection and distribution network will add significantly to cost

The different distribution of storage sites and, more importantly, storage capacity, as shown in Figures 2a and 2b has however a relatively limited effect on the system and its costs. While total pipeline length reached 5,116 km in the system in Figure 2a, corresponding length in the system in Figure 2b reached 5,046 km. Investments were reduced by € 1 billion in the system to the right, from € 10.3 to € 9.3 billion while specific cost went down from € 5.98/ton to 5.11/ton. However, the detailed German system will alone require investments corresponding to two thirds of the entire European bulk system as provided by JRC (see Figure 1a).

Large-scale CCS in EU likely to require offshore storage

A second factor that strongly affected the work in part 3 was the proposal by JRC to apply an upper limit on annual injection capacity in an aquifer. This is a highly reservoir specific parameter which is usually not known. However, after contacts with leading geologists (among others Erik Lindeberg, Sintef, Norway and Franz May, BGR, Germany) it was decided to apply a minimum injection period of 45 years. This led to that large amounts of CO_2 had to be exported from, among others, Belgium, Germany and Italy, to large aquifers in the Paris basin and in Poland. This is highly questionable for several reasons; a) the large opposition to onshore storage experienced in other parts of Europe, b) the risk of domestic opposition in France and Poland against storage of large amounts of foreign CO_2 and c) applied storage capacity and annual injection capacity in French aquifers corresponds to the conservative theoretical value given by the GeoCapacity project which is subject to significant uncertainties. Therefore, if France and Poland for some reason cannot (or will not) store large amounts of foreign CO_2, the risk is that offshore storage is the only remaining option for large-scale CCS in EU.

For further information: Jan Kjärstad, Chalmers

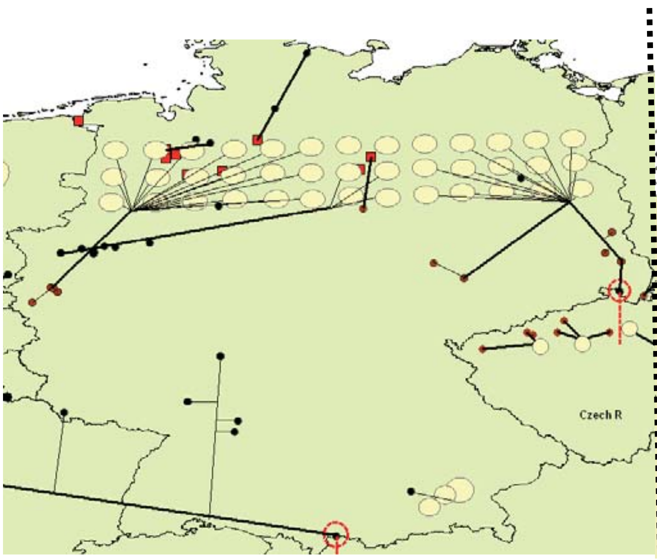


Figure 2a

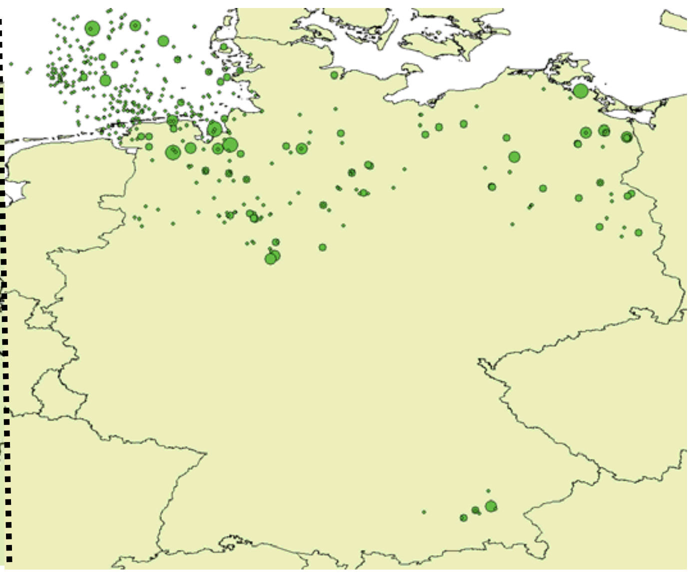


Figure 2b

March 2012

Increased power export from Sweden to Germany due to nuclear phase out policy:

Transmission network considerations

This paper presents the future outlook on the electricity supply system in Germany with the newly effective policy on nuclear power phase out. Nuclear phase-out not only affects the generation mix in the supply system and the trade balance with other countries, but also has a potential impact on the power transmission system. The effects are found to be most severe in the North-South transmission corridors. Furthermore, the strain on the transmission grid is increased in the Western part and reduced in the Eastern part. This would show clearly the needs for internal grid management strategies, both in short-term and long-term in order to minimize the transmission system effects without having to curtail loads and generation. Increased electricity export from the Nordic countries to Germany is possible up to several GW, but will cause bottlenecks in more than 10% of the German transmission lines.

German nuclear phase-out and Nordic electricity export

As a direct consequence of the Fukushima nuclear reactor accident in Japan, the German government agreed in June 2011 on a decision to finalize a complete nuclear phase out by the end of 2022 (BMU 2011). Furthermore, eight of the 17 operational reactors were shut down immediately in March 2011. This had a direct impact on cross-border electricity trade between Germany and the neighbouring countries, where the prevailing net export immediately was turned into a German net import (VGB Powertech 2012). Also in a longer perspective, it is reasonable to assume that Germany has to rely more on imported electricity due to the phase-out. The Nordic countries may supply a certain share of that electricity. Besides phasing-out nuclear power in Germany, ambitious European climate and renewable policies are likely to spur a significant increase in Nordic electricity export to Continental Europe (see e.g. “Increase in Nordic electricity export towards 2030” in this report). The question is, thus, whether the Continental grid is ready for such a significant increase in Nordic electricity export, or not?

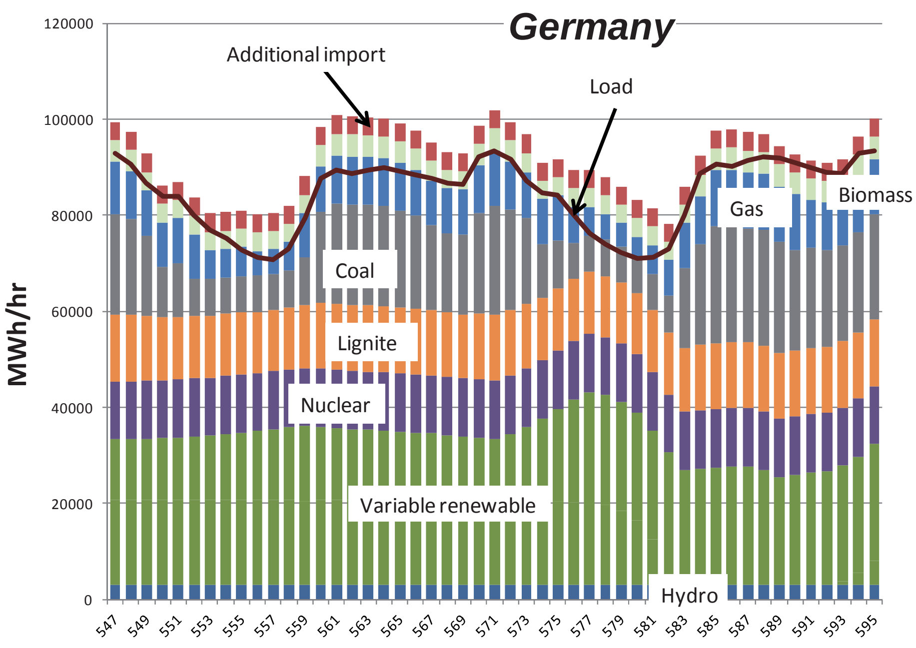


Figure 1: The generation mix for the Nordic import case, model year 2015.

The electricity supply scenarios

Taking into account the plans for nuclear phase out in Germany, the ELIN/EPOD of the integrated model tool box has been run for two cases, i.e., a ”Reference” case and a ”Nordic import” case. In the ”Nordic import” case, the Nordic net export is increased by 50 TWh annually as compared to the ”Reference” case. The description of the Nordic export scenarios can be found in “Increase in Nordic electricity export towards 2030” in this report These 50 TWh are considered as base-load export which is constant throughout the year. Out of these 50 TWh, two third is exported to Germany and the rest goes to Poland. This corresponds to 3.76 GW to Germany and 1.9 GW to Poland. Needless to say, the large amount of power import would have an effect on the supply scenario of Germany and Poland.

Figure 1 shows the supply scenario of the ”Nordic import” case mentioned above. The case also belongs to the overall “Climate Market” scenario as defined within the framework of the Pathways project. In this scenario the german phase-out is delayed.

Implications of the nuclear phase out policy in Germany’s transmission network

In this part, selected results of power flow calculation performed for the transmission network in Germany using DC Power Flow model to evaluate the effects of the generation supply scenarios for different cases as described above. Due to space limit, only the results of the two cases are shown.

Figure 2 shows the results of one case for Germany with the peak load data taken from ENTSO-E statistics for the third Wednesday in January 2011. This case is referred to as ” ENTSO-E Reference”. The generation power outputs from power plants are scaled up from original data of the approximate European transmission network model for the year 2011. Several loading limits of transmission lines are found to be violated. However, to represent a normal operating hour case, the transmission capacity of transmission lines in this system has been adjusted such that no big congestion would occur during this hour. This should be done due to the fact that the network should be managed by one way or another in order not to violate the transmission loading limits of the lines during operating hour. This adjustment corresponds to either operations of power flow control devices in the system or adding new transmission capacity on the lines. Where to put new transmission capacity is a question of transmission investment planning and this is however not the focus of this paper.

To evaluate the effects of the new policy based on our models’ runs, the generation power output of the ”Nordic import” case has been utilized in the power flow model. The results from the model is shown in Figure 3. As can be seen in the figures, about 12% of the total number of transmission lines in the systems get overloaded (as shown with the red circles) with the highest overload area being experienced in the North part of the system where there are power injections from the Nordic imports. The power has to be transferred from North to South direction which gets congested. Also, as compared to the original case with ENTSO-E data, there are more wind power off-shore in this case, which also contribute to the overloading of the network. It is also interesting to note that the power flow from East to West side have been decreased in the Eastern part of the system due to power flow redistribution in the system.

It is noted that the power flow calculation was done for a single hour (i.e., a ”snapshot”) with the intention to show the possible problems in the network in the future generation and load plan. In order to give a complete picture about how often internal bottlenecks would occur in the system, it is important to examine the system more extensively, i.e., using multi-period power flow calculation where the effects of variations in power generation, power exchanges between countries, and the load on the line flows can be captured. This will be further investigated.

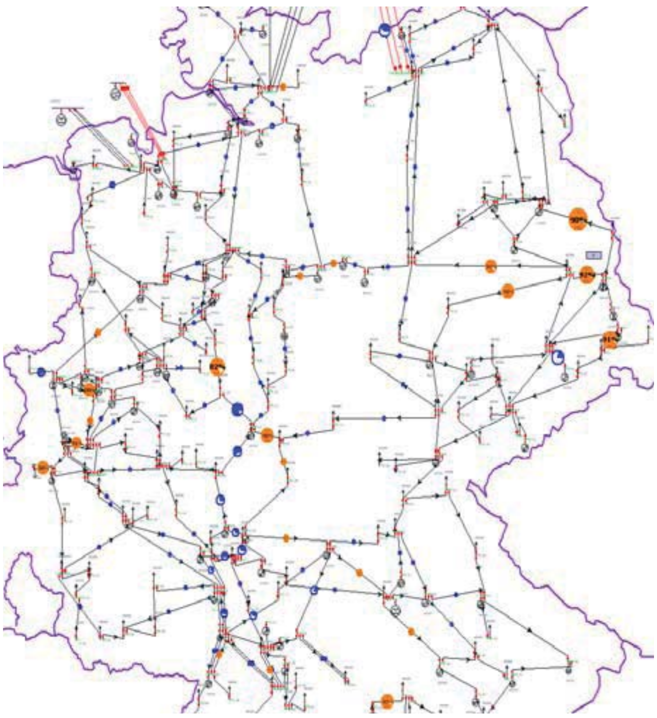


Figure 2: Results of ENTSO-E Reference Case, model year 2015

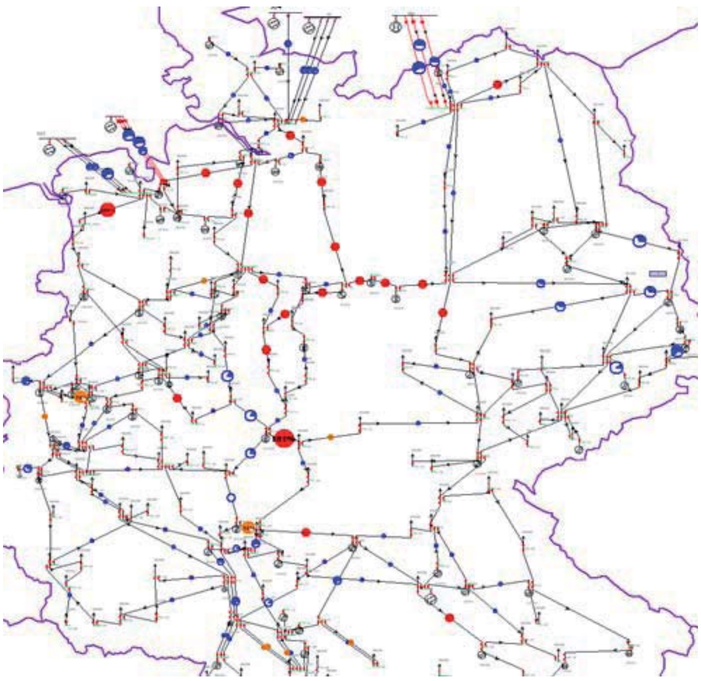


Figure 3: Results of Nordic Import Case, model year 2015

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EUROPEAN pathways

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February 2012

Prospects for radical reductions of CO_2 emissions from large industrial emission sources in the EU

Our analysis confirms that EU:s short-term goal for GHG emission reduction in the sectors covered by the EU Emission trading system, 21% reduction by 2020 compared to 2005, is attainable with abatement measures already available. The 21 % reduction is also manageable for the industry sector as such. However, despite optimistic assumptions regarding the potential for, and implementation of, available abatement strategies within current production processes, our analysis show that the industry sectors will fail to comply with more stringent reduction targets in the medium- and long term. A reduction of 80 % to 2050 is e.g. not possible to reach for the industry sector using present technologies/processes (”BAT”). Thus, to realize the goals of further, extensive, emission reductions, efforts to develop, and deploy, low carbon production processes (including CCS) must be intensified. This is also closely related to the risk of ”lock-in” if traditional processes and technologies are favoured.

Shift towards low carbon production technologies are needed

Many European industries and power and heat plants, still in operation, were commissioned in the period from 1960 to 1980 when most externalities accompanying the use of fossil fuels were ignored. Today there is a relatively broad understanding that to mitigate global climate change a shift towards low carbon production technologies are needed and the EU has committed itself to take a leading role in this process. In February 2011 the European Council reconfirmed the EU objective of reducing greenhouse gas (GHG) emissions by 80-95% by 2050 compared to 1990. To achieve such far reaching emission reductions all sectors of the economy, obviously, will have to contribute.

Explore the limits for CO_2 emission abatement

This study assesses the prospects for CO_2 emission abatement in three of the four major CO_2 emitting activities in the EU stationary sector by applying scenario analysis. The analysis covers petroleum refining, iron and steel and cement manufacturing, in EU27 and Norway. An important element of the analysis has been to consider how factors such as age structure, fuel mix, activity levels, demand structure and the types of production processes applied contribute to facilitating or hindering the shift towards less emission-intensive production. While some abatement strategies are applicable in all branches, i.e., fuel switching and energy efficiency improvements, the specific scenario generation approach has been adjusted to reflect the conditions in respective branch. The general methodological approach involves:

1) A thorough description and characterization of the current industry structure
2) Assessment of key factors and trends relevant to future CO_2 emissions in each branch
3) Scenario analysis; exploring the prospects for short- and long-term CO_2 emission reductions with the emphasis on the role of existing production processes and abatement options.
4) Impact analysis; including a discussion of the relevance and possible implications of the scenario outputs.

The overall aim has been to explore the limits for CO_2 emission abatement within currently dominating production processes. Thus, assumptions on the performances and potentials for specific individual abatement options can generally be described as optimistic. The analysis has been restricted to the technical potentials of available abatement options and, thus, largely neglects possible economical and institutional constraints. By comparing the emission scenarios with indicative emission trajectories for the period 2010-2050 we provide an indirect measure of the importance of new low carbon technologies or production processes.

The major share of the emission reduction occurs in the power sector

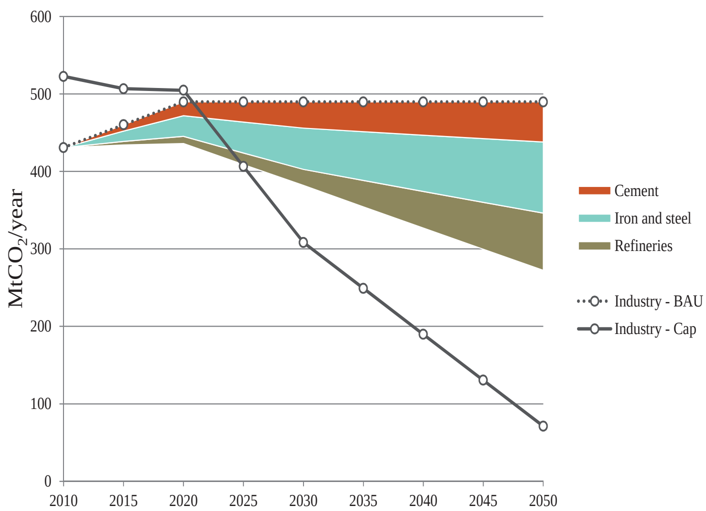
Three emission scenarios have been generated, one scenario for each of the industry sectors. In the iron and steel and cement industries, retired production capacity is replaced with new production capacity in line with the dominating technological designs albeit with improved performances in terms energy efficiency and CO_2 intensity (i.e. technological options that deviate from the existing processes have not been considered). In the refining industry possible new investments are assumed to be directed towards desulfurization units or advanced conversion units, no new investments in primary refining capacity takes place. Table 1 summarizes key drivers and estimated annual CO_2 emissions in each sector.

Table 1. *Emission scenarios and key drivers, by sector (EU27 and Norway).*

		2010	**2020**	**2050**
Petroleum refining	**Internal energy demand** (% of total transformation output)	7,1	7,2	7,5
	Total transformation output (Mtoe/year)	682	625	289
	Total CO_2 emissions ($MtCO_2$/year)	142	133	68
Iron and steel production	**Production structure** (Mt steel/year)			
	Primary steel (BF/BOF), of which - Existing capacity (%) - New capacity (%)	100 100 0	108 61 39	77 5 95
	Secondary steel (EAF) , of which - Existing capacity (%) - New capacity (%)	72 100 0	92 97 3	123 52 48
	Total CO_2 emissions ($MtCO_2$/year)	161	161	96
Cement production	**Total cement production** (Mt cement/year), of which - Existing capacity (%) - New capacity (%)	 190 100 0	 240 64 36	 240 6 94
	Average thermal energy consumption (MJ/t cement)	3770	3492	3093
	Clinker to cement ratio (%)	75	71	60
	Total CO_2 emissions ($MtCO_2$/year)	127	142	108

Industry sector would fail to comply with reduction targets

The estimated aggregate CO_2 emission reduction potential, over the period 2010-2050, amounts to approximately 160 $MtCO_2$/year, corresponding to a 40% reduction. However, despite the extensive measures assumed to be implemented, the results indicate that the industry sectors would fail to comply with the long-term reduction targets. The chart below shows the estimated abatement potential in the industry sector relative an aggregate business as usual scenario (i.e. frozen technology and fuel mix).



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