

The power of carbon

The impact of CO₂ emissions trading on Nordic electricity prices

A Point Carbon report for Enova SF
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Glossary

A

- **AA and AAU**, see Assigned Amount and Assigned Amount Units.
- **Additionality**
Under the Kyoto Protocol, certificates from JI and the CDM (see explanations below) will be awarded only to project-based activities where emissions reductions are "additional to those that otherwise would occur". The issue has to be elaborated further by the Parties to the Kyoto Protocol, and on the basis of practical experiences.
- **Annex B Countries**
Annex B countries are the 39 emissions-capped countries listed in Annex B of the Kyoto Protocol.
- **Annex I Countries**
Annex I countries are the 36 countries and economies in transition listed in Annex I of the UNFCCC. Belarus and Turkey are listed in Annex I but not Annex B; and Croatia, Liechtenstein, Monaco and Slovenia are listed in Annex B but not Annex I. In practice, however, Annex I of the UNFCCC and Annex B of the Kyoto Protocol are often used interchangeably.
- **Annex II Countries**
Annex II of the UNFCCC includes all original OECD member countries plus the European Union.
- **Assigned Amount (AA) and Assigned Amount Units (AAUs)**
The assigned amount is the total amount of greenhouse gas that each Annex B country is allowed to emit during the first commitment period (see explanation below) of the Kyoto Protocol. An Assigned Amount Unit (AAU) is a tradable unit of 1 tCO₂e.

B

- **Backwardation**
A market condition in which a futures price is lower in the distant delivery months than in the near delivery months. The opposite of contango (see below).
- **Baseline and Baseline Scenario**
The baseline represents forecasted emissions under a business-as-usual (BAU) scenario, often referred to as the 'baseline scenario' i.e. expected emissions if the emission reduction activities were not implemented.
- **BAU**, see Business As Usual Scenario.
- **Bear**
Someone who thinks market prices will decline.
- **Bull**
Someone who thinks market prices will rise.
- **Business As Usual Scenario (BAU)**
A business as usual scenario is a policy neutral reference case of future emissions, i.e. projections of future emission levels in the absence of changes in current policies, economics and technology.

C

- **Cap and Trade**

A Cap and Trade system is an emissions trading system, where total emissions are limited or 'capped'. The Kyoto Protocol is a cap and trade system in the sense that emissions from Annex B countries are capped and that excess permits might be traded. However, normally cap and trade systems will not include mechanisms such as the CDM, which will allow for more permits to enter the system, i.e. beyond the cap.
- **Carbon Dioxide Equivalent (CO₂e)**

This is a measurement unit used to indicate the global warming potential (GWP) of greenhouse gases. Carbon dioxide is the reference gas against which other greenhouse gases are measured.
- **CDM**, see Clean Development Mechanism.
- **CDM EB**, see Clean Development Mechanism Executive Board.
- **CERs**, see Certified Emission Reductions.
- **Certification**

The certification process is the phase of a CDM or JI project when permits are issued on the basis of calculated emissions reductions and verification, possibly by a third party.
- **Certified Emission Reductions (CERs)**

CERs are permits generated through the CDM.
- **Clean Development Mechanism (CDM)**

The CDM is a mechanism for project-based emission reduction activities in developing countries. Certificates will be generated through the CDM from projects that lead to certifiable emissions reductions that would otherwise not occur.
- **Clean Development Mechanism (CDM) Executive Board (EB)**

The CDM EB is accountable to the Conference of the Parties to the Kyoto Protocol (see below). It registers validated project activities as CDM projects.
- **Commitment Period**

The five-year Kyoto Protocol Commitment Period is scheduled to run from calendar year 2008 to calendar year-end 2012.
- **Contango**

A condition in which distant delivery prices for futures exceed spot prices, often due to the costs of storing and insuring the underlying commodity. The opposite of backwardation.
- **COP**, see Conference of the Parties.
- **Conference of Parties (COP)**

The COP is the supreme body of the United Nations Framework Convention on Climate Change (UNFCCC). The last conference (COP-10) was held in December 2004 in Buenos Aires, Argentina. COP-11 is scheduled to be held in Montreal, Canada in November/December 2005.
- **Countries with Economies in Transition (EIT)**

Countries that are in the transition from a planned economy to a market-based economy, i.e. the Central and East European countries, Russia, and the former republics of the Soviet Union.

E

- **EIT**, see Countries with Economies in Transition.

- **Emission Reduction Unit (ERU)**
Permits achieved through a Joint Implementation project.
- **Emissions to Cap (E-C):**
Emissions-to-cap (E-C) is calculated by subtracting the seasonally adjusted cap from emissions (actual or forecasted). This metric gives an indication of whether the market (for a specific period) is producing more or less than the seasonally adjusted cap for that same period. More specifically, if not taking CERs into account, a positive (negative) E-C means that the market is fundamentally short (long), suggesting a buy (sell) signal.
- **Emissions Trading**
Emissions Trading allows for transfer of AAUs across international borders. However, it is a general term often used for the three Kyoto mechanisms: JI, CDM and emissions trading.
- **ERU**, see Emission Reduction Unit.
- **EU ETS**, see European Union Emissions Trading System.

F

- **Financial additionality**
CDM projects have to be financially additional, which means that the projects that Annex I countries support within the framework of the CDM should not be financed by official development aid, but that additional funding is to be made available for such projects.

G

- **Grandfathering**
Method for allocation of emissions, where permits are allocated, usually free of charge, to emitters and firms on the basis of historical emissions.
- **Greenhouse gases (GHGs)**
Greenhouse gases (GHGs) are trace gases that control energy flows in the Earth's atmosphere by absorbing infra-red radiation. Some GHGs occur naturally in the atmosphere, while others result from human activities. There are six GHGs covered under the Kyoto Protocol - carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF₆). CO₂ is the most important GHG released by human activities.

H

- **Host Country**
A host country is the country where a JI or CDM project is physically located.
- **Hot Air**
Excess permits that have occurred due to economic collapse or declined production for reasons not directly related to intentional efforts to curb emissions.

J

- **JI**, see Joint Implementation.
- **Joint Implementation (JI)**
Joint Implementation is a mechanism for transfer of emissions permits from one Annex B country to another. JI generates ERUs on the basis of emission reduction projects leading to quantifiable emissions reductions.

K

- **Kyoto Protocol**
The Kyoto Protocol originated at COP-3 to the UNFCCC in Kyoto, Japan, December 1997. It specifies emission obligations for the Annex B countries and defines the three so-called Kyoto mechanisms: JI, CDM and emissions trading.

M

- **MAC**, see Marginal Abatement Cost.
- **Marginal Abatement Cost (MAC)**
The marginal abatement cost is the cost of reducing emissions with one additional unit. Aggregated marginal costs over a number of projects or activities define the marginal abatement cost curve.
- **Memorandum of Understanding (MoU)**
A MoU is an agreement between two parties that aims to formally recognise a joint desire to ultimately conclude an agreement or to achieve goals jointly. It may or may not have legal backing of sanction, depending upon how it is constructed. MoUs are often used as a basis for CDM/JI projects.

N

- **National Authorities and Designated National Authorities**
The national authority is the official body representing the Government which takes part in the arrangement of CDM/JI projects. For JI host countries, the national authority approves the projects and issues the emission reduction units. For CDM host countries, the designated national authority issues a non-objection letter necessary for the project approval.
- **Non-Annex I countries**
Annex I is an Annex in the UNFCCC listing those countries that are signatories to the Convention and committed to emission reductions. The Non-Annex I countries are developing countries, and they have no emission reduction targets.

P

- **Permit**
Permits are often used for denoting the tradable units under the Kyoto Protocol, i.e. AAUs, ERU or CERs.
- **Project Design Document (PDD)**
Document completed by project developers in order to register their project under the CDM.

S

- **Supplementarity** is a requirement in the Kyoto Protocol stating that emissions trading should be a supplement to domestic action. It reflects the request of the European Union to limit the use of the Kyoto Protocol flexibility mechanisms. It is still not determined how supplementarity should be interpreted.

U

- **United Nations Framework Convention on Climate Change (UNFCCC)**
The UNFCCC was established 1992 at the Rio Earth Summit. It is the overall framework guiding the international climate negotiations. Its main objective is "stabilisation of

greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic (man-made) interference with the climate system".

V

- **Verification**

In order for AIJ, CDM and JI projects to have a formalised validation of an emission reduction stream, a recognised independent third party must confirm that claimed emissions reduction activity has occurred.

1. Executive Summary

The first commitment period under the EU Emissions Trading Scheme (ETS) commenced on January 1 2005. The scheme covers some 10,000 installations in the EU countries, and is linked to some 100 countries through allowing the use of credits from Joint Implementation (JI) and the Clean Development Mechanism (CDM), two project based trading mechanisms for the transfer of emission permits under the Kyoto Protocol.

Allowances (EUAs) under the EU ETS started to trade on a forward basis in 2003, and the liquidity of the market has since increased rapidly to its current level of around 1 million EUAs per day. Prices for EUAs have historically been highly volatile, correlated to the developments in the power markets. The development of fuel prices as well as weather conditions, determining the demand for power, have had a discernible impact on the price for EUAs. Conversely, it has been reported that the EU ETS has had a significant impact on prices for power across Europe. This report seeks to answer the question: **Has the price of carbon been included in the long-term power contracts in the Nordic area?** Our main findings include:

Carbon impacts on power witnessed from January 2005. The impact of EU ETS on the power market is hard to quantify, but can be witnessed at Nord Pool where power prices have broken away from traditional strong correlations with hydrological conditions, and at the German EEX where the prices have been significantly higher than the short term marginal cost of production.

But carbon costs are far from completely incorporated. Overall, our analysis finds that the carbon cost is not being fully passed through into the Nord Pool spot price. Bearing in mind that the carbon market is still in its early days, we estimate the carbon price premium on Nord Pool spot prices to be in the region of 30-60%. Nevertheless, few players in the power market anticipated such a development. On the contrary, the analysis in this report finds that prior to 2005 there was no indication that carbon would be included in the power price.

Expectations of higher carbon prices not reflected in market. In our view many factors indicate that EUA prices in the second phase of the EU ETS (2008-2012) will on average be higher than for the first phase (2005-2007). However, the market appears to assume that supplies of external credits will be higher in the second phase, and that consequently prices will be lower: The price for EUAs is currently in backwardation, with the forward contract for 2008 trading €2.40/t below the forward price for 2007, at just over 10% difference.

Carbon costs an important driver for increased link between Nordic and German power price. As for the future impact of carbon on power prices in the Nordic area, the recent trend is that the Nord Pool forward price is increasingly linked to German power prices, with a correlation as high as 0.99 (i.e. nearly perfect) for the year up to 30 September. The development of a market for EUAs has probably been an important driver of this trend. EUA prices are reflected in the forward contracts for both German and Nord Pool power, and this has caused greater linkage between the two power markets.

Carbon not priced into long-term forward contracts. Currently, the German power market is in backwardation and there is little to indicate that carbon is priced into the long-term forward contracts – at least not at the market EUA price after 2007.

Re-evaluate ENOVA's subsidy model? The mandate of the study has not allowed for discussions on the implications our findings would have for the methodology ENOVA uses for estimating its subsidies for renewable energy and energy efficiency measures. Currently, ENOVA employs the long-term forward prices for power for establishing the level of support. Our report clearly indicates that future EUA costs are not reflected in current long-term power contracts. This might motivate further studies on alternative ways of determining the level of support by ENOVA.

2. Mandate and delimitations

This study has been commissioned by Enova SF, a public enterprise owned by the Royal Norwegian Ministry of Petroleum and Energy. Enova advises the Ministry in questions relating to energy efficiency and new renewable energy.

The introduction of the European emissions trading system has had a significant impact on the spot price development for electricity, an effect which was not anticipated by market participants and thus not priced into the short term forward prices. In light of this one might ask the question: has the price of carbon been included in the long-term power contracts, i.e. the 10 year forward?

This report seeks to answer that question by looking at the following elements in the carbon and power markets:

- How has the carbon price in the EU Emissions Trading System (ETS) developed?
- What will determine the long-term carbon prices, i.e. towards 2020 with a main focus on the period to 2012?
- How will carbon prices impact on power prices in the coming years?
- To what degree are the expected future carbon costs reflected in the long-term power contracts trading on Nord Pool?

The main focus of this report is the interaction between the EU ETS and power prices in the Nordic area, e.g. forward contract trading at Nord Pool. Hence, the report and model simulations do not go into depth regarding the impact on the German market. This is of course an important delimitation as the German and Nordic market have increasingly been interlinked over the last few months – to a large extent driven by the development of the EU ETS.

3. The EU Emissions Trading Scheme

3.1 Formal structure, opportunities for linking

The EU Emissions Trading Scheme (ETS) is the cornerstone of EU climate policy and the key measure for complying with emissions targets set under the Kyoto Protocol. The EU ETS was created by directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a scheme for greenhouse gas emissions allowance trading within the Community and amending Council Directive 98/61/EC. The EU ETS covers all of the EU 25 countries, with a total of some 10,000 installations, receiving approximately 2.1 billion EUAs per year in the first trading period 2005-2007.

The linking directive allowing CERs and ERUs to be used for compliance purposes by installations falling under the EU ETS, was created by directive 2004/101/EC of the European Parliament and of the Council of 27 October 2004 amending Directive 2003/87/EC establishing a scheme for greenhouse gas emission allowance trading within the Community, in respect of the Kyoto Protocol's project mechanisms which at the time of writing might be undertaken in the some 100 countries that have signed the protocol.

The linking directive also allows for establishing formal links to emissions trading schemes outside the EU, e.g. like Norway, Canada and Japan through so-called mutual recognition agreements (Art. 25). However so far no non-EU countries have expressed much interest in such a solution with the exception of Norway (which might in the end adopt the directive rather than establish a linked system).

3.3. Allocation and participants

The EU Commission (EC) has approved in total 6.3 billion allowances to be issued for the period 05-07, excluding allowances set aside for new installations as well as opt-ins and opt-outs, resulting in an average of 2.1 billion allowances to be distributed each year. Comparing this to 2003 emissions, we find that the EU ETS covers 44 % of all greenhouse gas (GHG) emissions in the EU. However, MS' initial applications were for even more. The EC ended up cutting almost 300 Mt of allowances, or more than 4 % of the total volume, from the initial volumes of allowances as submitted in the draft NAPs.

The annual average cap is distributed among the MSs as shown in figures 3.1 and 3.2. Germany is by far the MS with highest number of allowances (488 Mt/year), followed by Italy, Poland and the UK pending around 250 Mt each for the first trading period, and France and Spain around 150 Mt. Together, these six countries constitute 71 % of the total allowances in the market.

Figures 3.1 and 3.2 also show calculated CO₂ emissions for the years 1990 and 2003 in the sectors now covered by the EU ETS. The majority of the countries have had to reduce their emissions compared to their 2003 level, although increases were allowed in some countries.

Fig 3.1 EU member states with more than 100 Mt in aggregated allocations for the 2005-2007 period. Emissions in ETS sectors in 1990, 2003 and allocated in 2005, in Mt CO₂

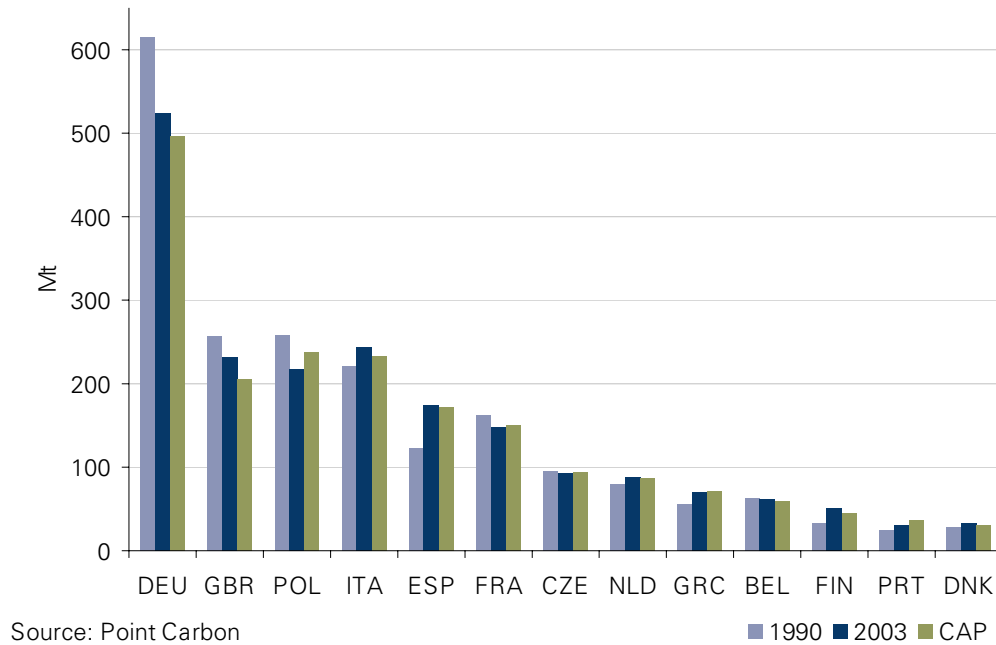
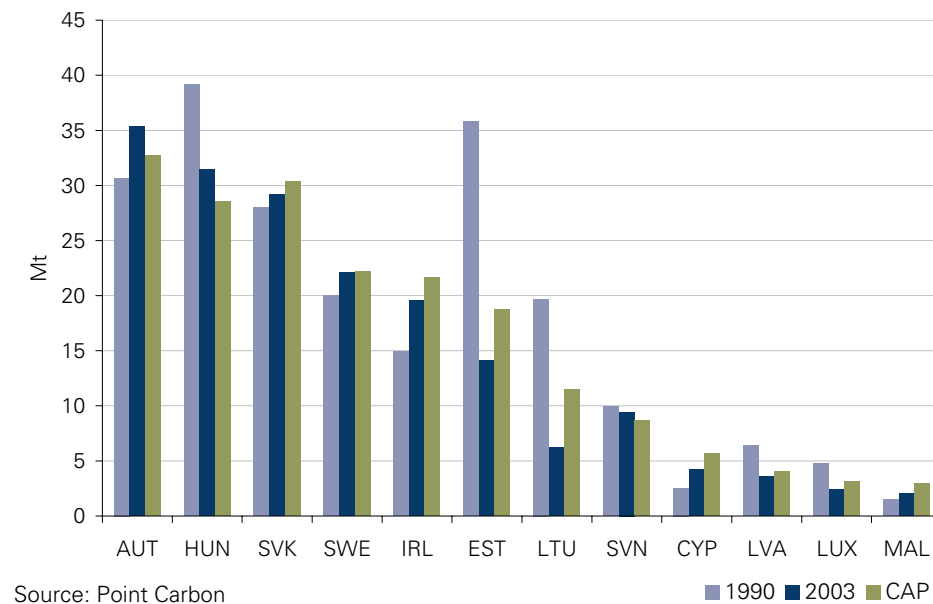


Fig 3.2 Total allocations to some of the smaller EU member states, aggregated for period 05-07. Emissions in ETS sectors in 1990, 2003 and allocated in 2005, in Mt CO₂.

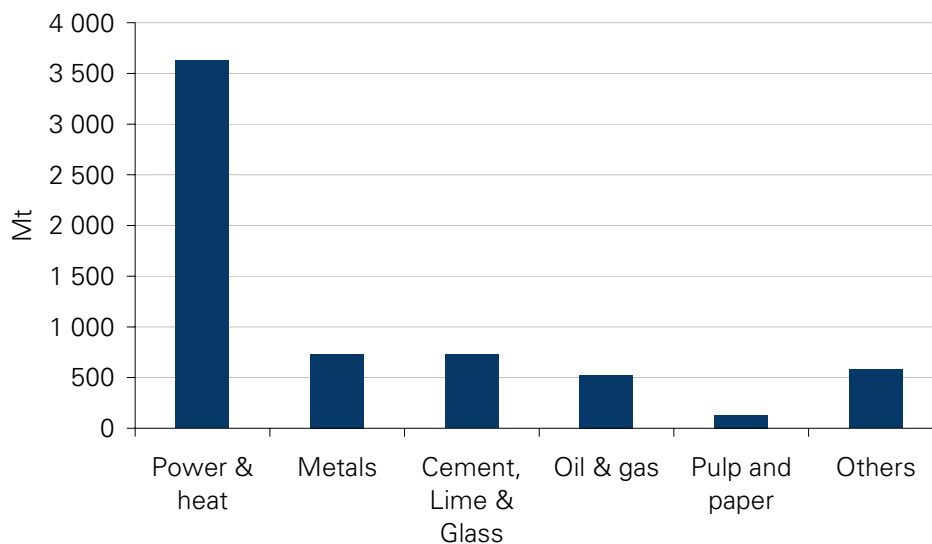


Within each MS the allowances are allocated to existing installations in 5 different sectors, as well as to the New Entrant Reserves (NERs). The following shows the distribution between the sectors, as well as between the smaller and larger installations within the system.

EXISTING INSTALLATIONS

The EU ETS comprises five main sectors, and figure 3.3 illustrates the distribution of allowances between these. The power & heat sector is by far the largest sector, accounting for 55 % of all allowances in the system, making the EU ETS primarily dependant on activities and changes within this sector.

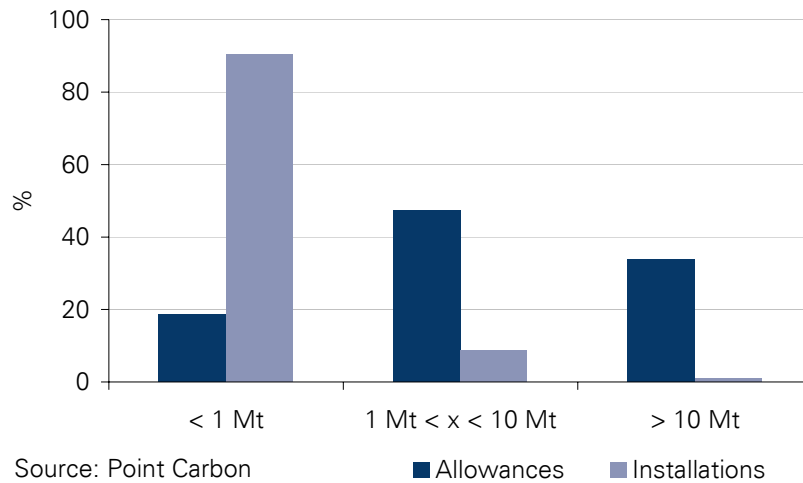
Fig 3.3 Total EU ETS allocations on sector level, aggregate for 2005-2007 period, in Mt CO₂.



Source: Point Carbon

One key issue of the NAPs has been deciding at country level which installations should be covered by the EU ETS. About 10,000 installations now have commitments within the EU ETS. Figure 3.4 illustrates the distribution of allowances and installations categorised relative to the size of the installations. According to the currently available installation lists, there are 92 large installations with an allocation of more than 10 Mt CO₂e in the 3-year period 05-07. Together these account for only 0.9 % of the total number of installations but for a whopping 34% of the total allowances. At the other end of the scale, we find that there are close to 9,000 small installations emitting less than 1 Mt CO₂e, totalling only 19% of the allowances but more than 90% of all installations. However, it is the medium sized emitters, between 1 and 10 Mt, which have the largest amounts of allowances, accounting for 47% of the total amount.

Figure 3.4. Distribution of allowances and number of installations according to size categories for installations; less than 1 Mt, between 1 and 10 Mt, and larger than 10 Mt.



NEW INSTALLATIONS

In addition to allocating allowances to existing installations, the MSs have set aside in their NAPs some allowances for new installations, the so called New Entrant Reserves (NER). Based on the current version of MS NAPs, the total potential size of the NER is around 200 Mt, accounting for 2.35 % of all allowances. However, uncertainty about the potential supply from NERs still remains, most notably as Italy, with a suggested NER of 61.5 Mt, has yet to make a decision on how to distribute the cut of 69 Mt required by the Commission, whether from the allocation to existing installations or from the NER.

The NERs are currently only available for new entrants, but unused NERs might be made available to the market later in the first trading period. There are basically two options for how the NER surplus is dealt with, either by auction to the market or cancellation. From a demand and supply point of view, it does not make any difference whether NERs are made available through new installations or through auctions; they represent net supply to the market in any case.

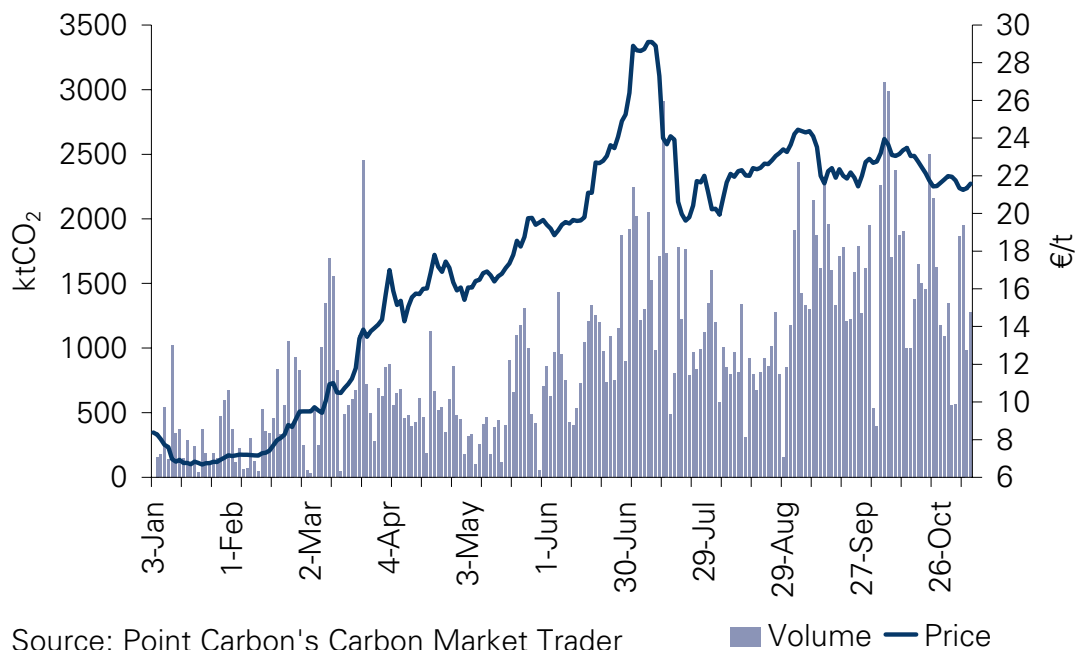
4. Price formation in the EU ETS

In the EU ETS, as in every commodity market, the price is determined by the relationship between supply and demand. In this case, the demand for allowances is determined by the relationship between CO₂-emissions and the cap. Greater distance between these indicates a higher demand. The supply is determined by the amounts of EU allowances (EUAs) and Certified Emission Reductions (CERs) from CDM projects brought to the market. In addition to the EUAs already allocated to existing installations through the NAP process, allowances issued to new entrants and/or through auction of NER surplus will increase the supply.

4.1 Development of prices and traded volumes

So far in 2005, prices have proven to be highly volatile as players have gotten used to dealing with this new commodity. Following a slow start at around €6/t - €8/t in January and February 2005, the EUA prices steadily increased, influenced by NAP-decisions and higher oil/gas prices, to some €20/t in mid-June. The EUA prices then rose sharply and peaked close to €30/t in early July. Since mid-July it has returned to a more stable level in the low-twenties (€21/t – €24/t), with the current EUA price at €22.70/t (11 November 2005). (See figure 4.1 for the price/volume developments so far in 2005).

Fig 4.1. Volume of EUAs traded and price Jan-Oct 2005



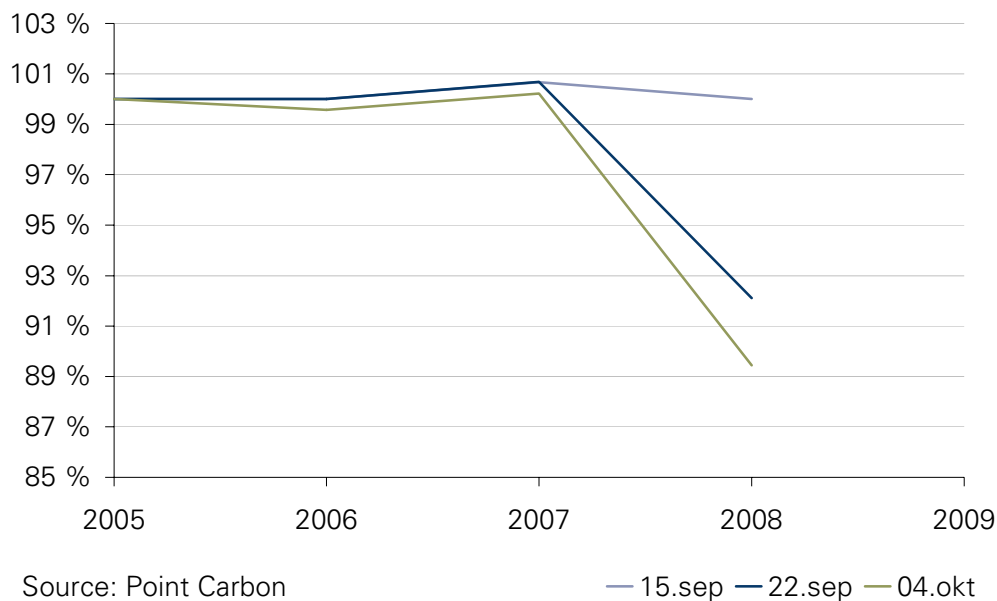
So far in 2005 (year-to-date 15 November 2005) a total of 214.2 Mt have been transacted in the European carbon market. 80% of this has been through the over-the-counter (OTC) market, i.e. through different brokerages. The remaining 20% has taken place through the 5 different

exchanges serving the carbon market: Nord Pool in Norway, the European Climate Exchange in Netherlands, EEX in Germany, EXAA in Austria, and Powernext in France.

4.2 Development of the forward curve

Recently the EU ETS market has been in backwardation on the forward curve to 2008. Figure 4.2 shows the development of the forward curve from 15 September this year to 4 October. It is shown that in this 2 week period the market introduced a discount on allowances for phase 2 of the EU ETS, increasing to more than 10% down from phase 1. This is in contradiction to Point Carbon's expectations for the market, as explained in more detail in Chapter 5.

Fig 4.2. EUA forward curve



4.3 Identification of key price drivers

Market fundamentals in the carbon market, similar to other markets, concern demand and supply. The *supply* of allowances - the right to emit one tonne of CO₂ - is fixed by governments through the National Allocation Plans (NAPs). In brief, governments in Member States will first determine the total quantity of allowances to be allocated (the 'cap'), and then allocate the allowances to installations in energy intensive industries (e.g., production of iron and steel, building materials, pulp and paper) and the power and heat generation sectors. The *demand* for allowances is in turn a function of the level of CO₂ produced by the companies and installations covered by the scheme.

ESTIMATING AND FORECASTING CO₂ PRODUCTION

In order to monitor and forecast the demand side of the EU ETS, Point Carbon has developed a unique set of models that provide continuous updates and forecasts of CO₂ production for all sectors in each of the countries covered by the EU ETS. The models draw upon a wide variety of input data and structural information, including for instance detailed information about

installations in the power and heat sectors (e.g., installed capacity (MW), efficiency, and availability).

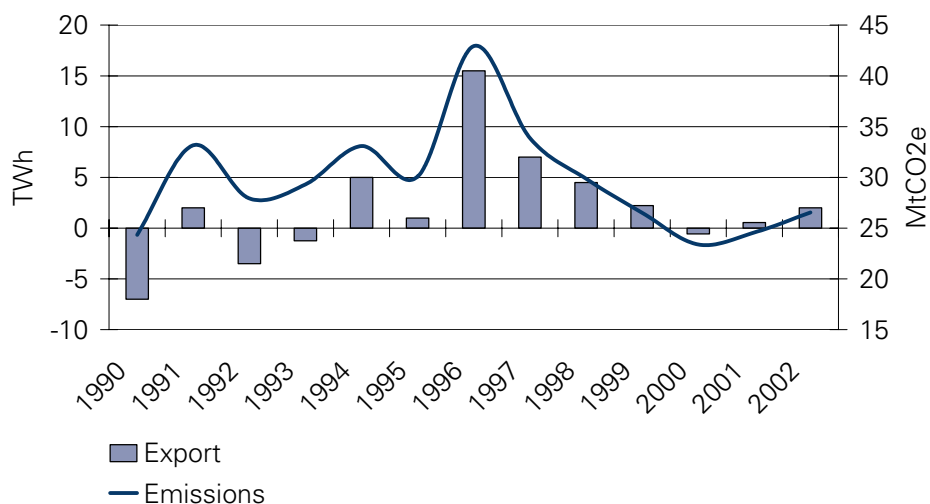
In general, CO₂ production depends on a number of factors, such as weather data (temperature, rainfall, and wind speed), fuel prices, carbon prices and economic growth. Among these factors, weather has a double effect; firstly, cold weather increases energy consumption and so CO₂ emissions through power and heat generation. Secondly, rainfall and wind speeds will affect the share of power generated by non-emitting sources and thus emission levels. This is of course particularly important for countries and regions relying on hydro- and/or wind power to any significant extent.

THE IMPACT OF WEATHER

Consider for instance the Nordic Power Exchange area. During dry years, CO₂ emissions tend to soar along with the price of power, with Norway and Sweden drawing power from the pool at higher levels and coal-fired generation in Denmark and Finland ramping up. The Danish emissions profile is thus a good litmus test for the impact of weather.

As shown in figure 4.3, annual emissions from power and heat generation in Denmark during the period 1990-2003 fluctuated from a low of about 24 MtCO₂ in 1990 to a high of 42 MtCO₂ in 1996, an exceptionally dry year, representing a swing of about 70% from the lowest to the highest level. According to the Danish NAP, the public power and heat sector will be allocated an average of 21.7 MtCO₂ annually in the first period 2005-2007. This is approximately 40% less than projected emissions for the period 2005-2007 and lower than any year during the 1990s. Hence, even under 'normal' circumstances, not to mention what could happen if for instance 2005 proves to be another dry year like 1996, Danish power and heat producers will have to cover a potentially significant short position through the market.

Fig 4.3. Danish power exports (left axis – bars) and emissions from the power and heat sector (right axis – line) for the period 1990-2002.



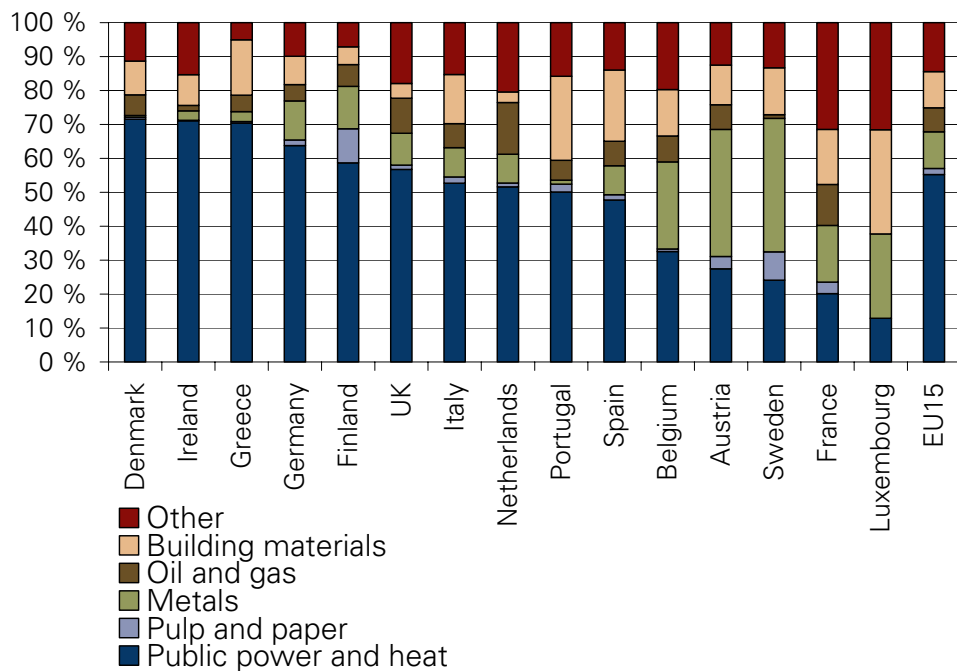
Source: Point Carbon (www.pointcarbon.com) and Energistyrelsen (www.ens.dk)

Hence, the message is clear – weather can cause a swing for power producers and flip their position vis-à-vis its cap from short to long and back during a season. This is similar to the case for the power markets, thus weather could become a key price driver in the short term and possibly increase volatility. For instance, the combination of a cold winter and a warm summer could cause power consumption and emissions to soar, which would provide a clear bullish signal.

THE ROLE OF FUEL SWITCHING

While the marginal CO₂ abatement cost might in the long run direct investment towards abatement projects, fuel switching from coal to gas for power and heat production is probably the single most important measure in the short term. This is firstly because the public power and heat sector is the largest in terms of emissions for most of the current Member States. As illustrated in Figure 4.4, public power and heat represent more than 70 per cent of total emissions covered by the EU ETS in Denmark, Ireland and Greece, and about 60 per cent in Germany and the UK, representing the two single largest emitters.

Fig 4.4 Share of emissions by sector covered by the EU ETS for EU 15 in year 2001



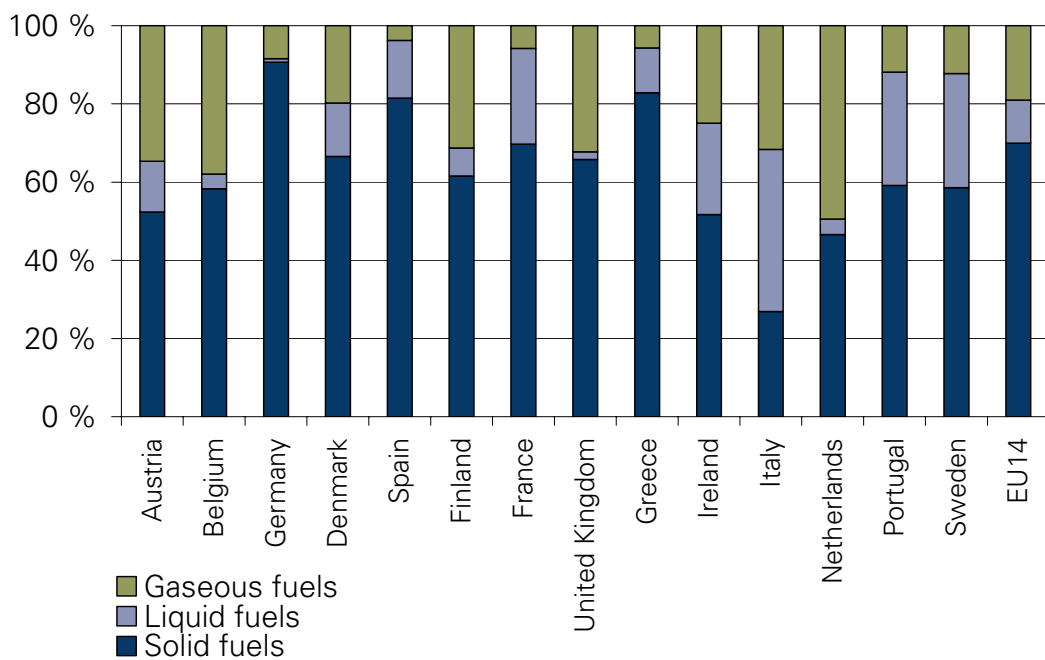
Sources: Eurostat and Point Carbon (www.pointcarbon.com)

Secondly, and even though burning any fossil fuel creates CO₂ emissions, coal causes about two times that of natural gas per consumed unit. Figure 4.5 shows that solid fuels (hard coal, lignite) accounted for about 70 per cent of total CO₂ emissions from public heat and power stations in current Member States (less Luxembourg, EU14) in year 2001. The figure also shows that the share of emissions by fuel varies between countries, depending on factors like resource

endowments, fuel prices and state subsidies/taxation. For instance, solid fuels accounted for almost 90 per cent of emissions from thermal power stations in Germany, but only about 26 per cent in Italy. In comparison, natural gas is an important fuel in countries like the Netherlands, Austria, Belgium and the UK.

There is a considerable scope for switching from coal to natural gas and other liquefied fuels in several Member States, most notably Germany and Spain. Hence, in order to forecast CO₂ emissions into the future, it is also important to monitor developments in fuel prices and assess its potential impact on fuel switching.

Fig 4.5 CO₂ emissions from public heat and power generation in year 2001 by fuel



Source: European Environmental Agency (<http://eea.eu.int/>)

5. Future prospects for the carbon market

5.1 Prospects for the remaining of phase I in EU ETS

At the time of writing, the allocation process is more or less finalised, although a few issues are still outstanding (e.g. the Italian New Entrant Reserve). The next important policy decisions are the treatment of the New Entrant Reserves, or rather whether these allowances will be auctioned or cancelled.

In addition to the result from this policy processes which might significantly change the price level, another important event will be the publication of the 2005 emissions for the various installations covered by the scheme. Whether or not, this data will confirm the overall shortage of allowances currently assumed by the market participants, and hence reflected in the price, could have significant impact on the price level.

However, as has been the case in the EU ETS up to now, shifting fuel prices and weather conditions will probably continue to explain much of the short term dynamics of the price development for EUAs.

Finally, as the final delivery for EUAs approaches, e.g. in first quarter of 2008, market volatility could increase dramatically. E.g. if the market is expecting a shortage towards the end of the period; for example extraordinary weather conditions, could lead to periods with extreme price fluctuations.

5.2 The 2006 review of the scheme: any changes?

Article 30 of the ETS Directive lays down that the Commission will submit a report on the application of the Directive to the European Parliament and the Council by 30 June 2006. This report should include a review and proposals for the further development of the scheme. Furthermore, the Competitiveness Council of March 2004 invited the Commission to provide an assessment of the effect of the scheme on the competitiveness of European industry. This proposal is intended to help the Commission conduct the required review and assessment and provide the Commission with suggestions for the further development of the Directive.

The following table presents the articles that have been scheduled for review.

Articles for review	Issues
Article 30(2)(a) how and whether other relevant sectors, activities and/or emissions should be included	<p>What are the possibilities to expand the scheme?</p> <p>What are the characteristics of the different alternatives (volume, cost curves for abatement, number of participants, monitoring)?</p> <p>Which alternatives can improve the scheme's economic efficiency?</p>

<p>Article 30(2)(c) Harmonisation of the allocation method and the criteria for the national allocation plans</p>	<p>Differences in the definition of installation.</p> <p>The dilemma of coordinating existing climate change policies with the NAP.</p> <p>Differences in national reduction targets.</p> <p>Is benchmarking a feasible methodology across Europe?</p> <p>Can operators incur their Opportunity costs?</p> <p>What impact will auctioning have?</p> <p>Harmonized treatment of cogeneration.</p>
<p>Article 30(2)(d) Use of credits from project mechanisms</p>	<p>To what extent are European companies investing in project mechanisms?</p> <p>How could future credit flows affect the scheme's performance?</p> <p>What would be the effects of various options to amend the Directive?</p>
<p>Article 30(2)(g) The level of excess emission penalties</p>	<p>Development of inflation.</p> <p>Price development of emission allowances.</p>
<p>Article 30(2)(h) The functioning of the allowance market</p>	<p>Is the market functioning effectively?</p> <p>What can be done to make the market more effective?</p>
<p>Article 30(2)(j) Pooling</p>	<p>To what extend is pooling being used?</p> <p>Is the way pooling is organised sufficient?</p>
<p>Article 30(2)(k) benchmarking as a basis for allocation</p>	<p>See harmonisation of allocation.</p>

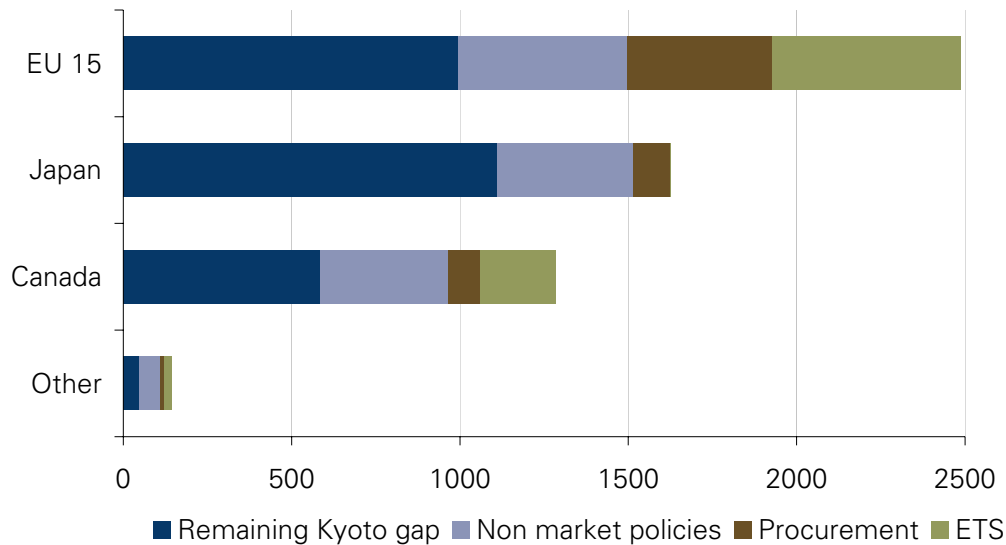
Although this is a fairly long list, Point Carbon does not expect many changes in comparison to today's scheme. The possible exception is that aviation might be included, but then probably from 2010.

5.3 Supply and demand in the Kyoto system

The countries which are expected to be short for the Kyoto period includes Western Europe, Canada, Japan and New Zealand. Countries in Central and Eastern Europe are expected to remain as net sellers in the Kyoto period. Point Carbon has previously conducted a study based on emission projections towards 2012, the estimated impacts of current policy plans, as well as estimates for the use of domestic and international market mechanisms, to see what the overall supply and demand in the carbon market would be.

The business-as-usual emissions for all countries would leave them some 5,540 Mt above their agreed targets for the full Kyoto period, 2008-2012. However, including the impacts of all agreed policies and measures, carbon credit procurement plans, and expected future emissions trading requirements, we find that the buyer countries will be about 2,740 Mt short for the five-year Kyoto period, see figure 5.1. This is 9.5% above these countries' Kyoto targets.

Fig 5.1. Effect of policies and carbon procurement on final gap to Kyoto target in Million tonnes (Mt) of CO₂e



Source: Point Carbon

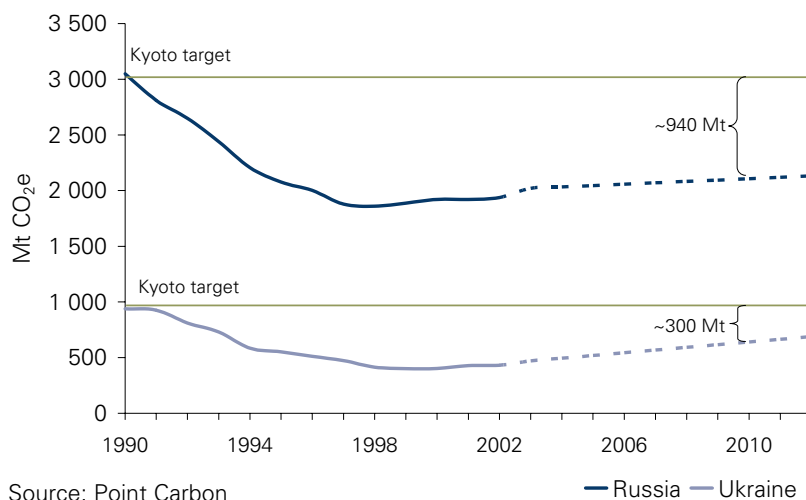
Some Western European countries are on path to meet their targets, but the majority of the countries studied are set to land in non-compliance unless additional measures are introduced. Overall the EU15 bubble is set to miss its target by an uncomfortable 995 Mt on aggregate. Japan and Canada are the individual countries set to have the largest shortfalls in terms of tonnage - with 1,111 Mt and 585Mt respectively - although Italy is a close third with an estimated 526 Mt. Spain, Italy, Canada and Japan are currently going to be out by the biggest percentage, all of them at 20% or above.

Our analysis assumes that it will not be politically acceptable to severely strengthen the EU ETS from 2008, as it will be difficult to allow for much higher carbon prices, in particular due to its expected impact on power prices. Thus, we have assumed that allocations for the next phase of EU ETS will be similar to the 2005 to 2007 period. This should not be interpreted as a forecast for the 2008 to 2012 period, which will involve assumptions on future power demand and relative fuel price development.

Assuming that the total supply of credits from the Clean Development Mechanism and Joint Implementation would be 1,200 Mt by 2012, this leaves a total gap of about 1,500 Mt to fill. This indicates that countries will have to look towards Central and Eastern Europe, and in particular Russia and Ukraine, in order to acquire the necessary emission allowance.

Under Point Carbon’s reference scenarios, illustrated in Figure 5.2, the potential aggregated supplies from Russia and Ukraine (in the five-year 2008-2012 period) are some 3.2 and 2 GtCO₂e, respectively. These volumes can be sold without implementation of any new abatement measures. In addition there is an enormous potential for low-cost reductions. While the Soviet infrastructure was extremely wasteful and inefficient, the reduction potential became even larger during the economic downturn in the 1990s when the carbon intensity of the economies tended to increase. However, in order to be able to participate in emissions trading and JI, Ukraine and Russia will have to meet the eligibility criteria set out in the Marrakech Accords.

Figure 5.2. Point Carbon’s business-as-usual scenarios for Ukraine and Russia



Because of the size of the potential volumes Ukraine and Russia can provide, they are often expected to become key players and price setters in the future carbon market under the Kyoto Protocol. Moreover, since their potential supply, together with the other Central and Eastern European countries, by far outstrips expected demand in industrialised countries, the price of allowances is often assumed to become low. E.g. under a business-as-usual the total potential supply from Eastern Europe is likely to be in the order of some 7.5 billion tCO₂e, while the expected demand will probably be in the order of some 5.5 billion tCO₂e¹.

However, it is far from certain that Russian and Ukrainian supplies will depress prices. Firstly, as mentioned above, it is still unclear whether they will be able to become formally eligible for trading. And secondly, in light of the fairly strange and partly interlinked carbon market that is emerging, assessing the impact on the various market segments from Russian/Ukrainian supplies is far from straight forward.

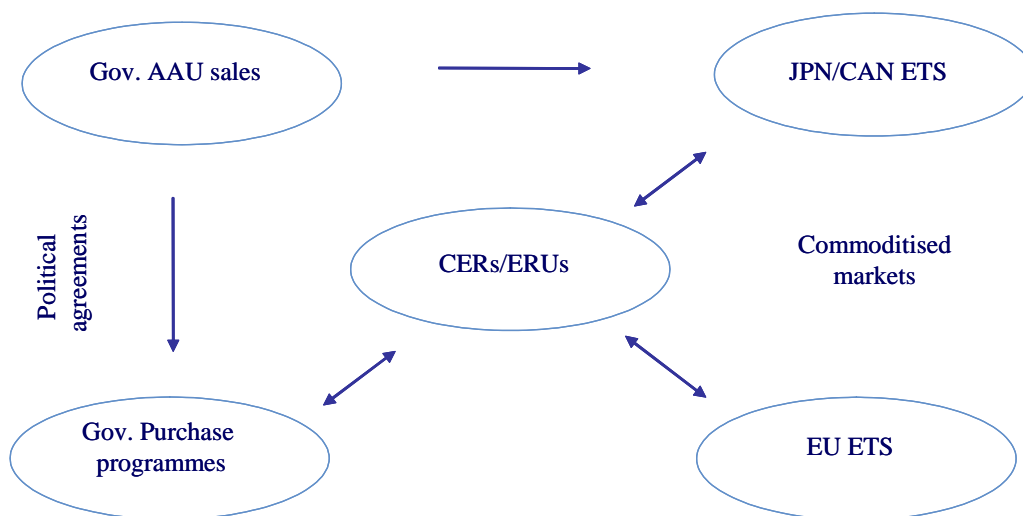
¹ Carbon Market Analyst, September 12, 2005.

5.4 The Kyoto system: linkages between market segments

While the EU ETS today trades for the compliance periods in 2005-2007, the market will in the future depend to a larger degree on the market structures that are established on the international level, in particular the markets for country compliance under the Kyoto Protocol in the 2008 to 2012 period. Figure 5.3 provides an illustration of the various segments in the carbon market, and their possible levels of linkage, in what currently appears to be a fairly realistic scenario. The carbon market is here divided into two main blocks, with the government market on the left hand side trading in Assigned Amount Units (AAUs), the tradable unit under the Kyoto Protocol, and the private sector market, e.g. EU ETS, on the right hand side. The link between the two market 'blocks' is the CDM market, as both governments and companies can use the credits from this market for compliance purposes.

As the figure illustrates, we find it quite unlikely that trading with AAUs will develop into a commoditised market, such as the EU Emissions Trading Scheme (ETS) and future private company schemes in Japan and Canada. Rather, AAU trading will probably be done through large-scale government-to-government agreements where the transfer of allowances will be bundled to various forms of assistance, cooperation and other conditions. Hence, unlike the EU ETS, the AAU market will probably be illiquid and without clear reference prices.

Fig 5.3. Expected future market segments and their links



The largest market segment by far (measured as financial turnover), will probably be the EU ETS. However, it is questionable whether the price development in the segment will be affected by sales of AAUs from Russia and Ukraine. The most important factor determining the price in the EU ETS will be the overall allocation in phase 2, and signals on this will emerge in 2006, i.e. several years before any AAUs can feasibly be transferred. Hence, as Figure 2 illustrates, sales of AAUs will only affect the EU ETS if it means that it increases the supply of credits from the Clean Development Mechanism (CDM) and JI into the scheme.

The current trends indicate that the demand for Certified Emission Reductions (CERs, from CDM projects) and ERUs will by far outstrip the likely supply. Even with the current rapid implementation of CDM projects, and assuming that this trend will continue towards 2012, total aggregated volumes of CERs to be issued before 2012 will probably be in the order of 700-800 MtCO₂e and JI (track 2) is expected to supply an additional 300 MtCO₂e. As a comparison, the credit purchase programmes for which there currently are fairly firm plans, aims to buy some 700 MtCO₂e². In addition, beyond existing policies for internal reductions and plans for external procurement, the big buyers under the Kyoto Protocol will have to purchase another 2.7 GtCO₂e, for which they currently have no plans.

In order to meet this gap, countries will have to utilise the international carbon market, as the potential for internal reductions is limited in the period towards 2012. Government demand will also probably focus on CERs and ERUs as these credits are based on emission reductions that are clearly driven by the Kyoto Protocol, and do not have the connotation of “hot air” trading, as is the case with AAUs. In this case the price of CERs and ERUs will primarily be driven by the EU ETS price, as the main linkage between governmental and private markets will be through CDM/JI. This situation could arise if the supply of AAUs is, for whatever reason, limited, and/or if the demand for AAUs from buyer countries, primarily for political reasons, does not materialise.

In a different scenario, buyer countries focus on the purchases of AAUs rather than CDM and JI. With the majority of carbon demand met through the country-to-country market there will be more CERs and ERUs available for players in the EU ETS, and prices in these markets could experience downward pressure. Here, the price is primarily driven by the extent to which AAU seller countries will make their allowances available on the market.

However, it is also possible that the carbon market remains fragmented, with different credits and allowances trading at different prices. We could well see a situation where all market segments are liquid and clear reference prices emerge, but where each segment operates in relative isolation to the other and price formation (for CERs/ERUs, EU allowances, and AAUs) takes place according to different logic in different segments.

5.5 Implications for EUA price formation in the Kyoto period

While the above analysis focuses on all market segments in the Kyoto period, it does give some indications on how the EU ETS prices might develop in the 2008-2012 period. We find it reasonable to assume that:

- 1) the allocation in phase 2 of the EU ETS will become tighter than in phase 1
- 2) supply of credits from JI and CDM will be limited, and in high demand

Consequently, as long as increased demand for reductions are not counteracted by increasing supply, prices in the EU ETS would in general be higher in the second phase than in the first. There are some developments might change these conclusions, such as:

² Carbon Market Analyst June 9, 2005.

- High supply of AAUs lead the governments to buy AAUs instead of credits from projects, leading to higher supply of credits into the EU ETS and hence lower prices
- Point Carbon has underestimated the volumes of credits that will be issued on the back of JI and CDM projects. This could happen for example happen if a very liberal interpretation of the so-called track 1 for JI projects leads to a massive generation of unexpected credits.
- The EUA prices turn out to have sever consequences for power consumers and as a consequence the allocations for the second phase becomes laxer than in the first phase

However, in our view none of the developments appear very probable, and hence our basic scenario is that average prices in the second phase will be higher than for the first phase.

5.6 Post-2012 and the impact on prices in the period 2008-12

The faith of the on-going negotiations over an international protocol to succeed the Kyoto Protocol, could significantly impact the price development in the Kyoto Period. The Kyoto Protocol allows for banking of allowances, e.g. allowances that are not used in one period can be saved in to the next. Hence, in principle a strong protocol for post-2012 could mean that many countries choose to bank their allowances rather than using them for compliance. In principle the price in the 2008-12 period would then rise to the level assumed for the post-2012 period.

The negotiations on a future climate agreement are scheduled to start this year, with the U.N. climate meeting in Montreal, Canada in November and December marking the first meeting since the Kyoto Protocol entered into force in February. However, it is questionable whether much progress will be seen in Montreal. There are still a number of difficult crunch issues remaining that need to be solved, including: re-engaging the USA in the international climate regime, agreeing on commitments for developing countries, new emission targets for countries with commitments under Kyoto. All of this must be solved while simultaneously avoiding stalemate (and breakdown) in the negotiations.

The current situation regarding post-2012 commitments is that the EU and some likeminded countries favour a continuation of the Kyoto Protocol, perhaps with added technological aspects. The official EU position is to explore pathways that could lead to reductions in the order of 15-30% by 2020. USA, Australia, and Japan have all signalled that they favour a technology solution for the future of the climate regime, and have all signed up to the Asia-Pacific Partnership on Clean Development. While this has been presented by some as an alternative to the Kyoto Protocol, our opinion is that this is primarily a PR effort without any real content so far.

However, the situation might not be as bleak as the analysis indicates. Developments at state-level in the U.S. suggest that emissions trading could become a reality in the future- Also, it is feasible that a federal emissions trading system in the USA could be established without U.S. re-entry to the international climate regime, following increasing state-level regulations and industry pressure for certainty on long-term regulatory frameworks. Furthermore, developing countries have also shown to be getting more proactive on climate change, and this could be strengthened further if policy developments are witnessed in the US.

6. Carbon impact on power prices

6.1 Background

Power and Heat is one of the sectors included in the EU ETS, and installations that emit CO₂, like thermal power plants using coal, are given an upper level (cap) on their CO₂ emissions by the authorities. Generally, around 95 % of the historic CO₂ emissions are allocated for free to the installation as tradable securities (EUAs). Installations must by the end of the first trading period in March 2008 surrender allowances corresponding to their emissions to be in compliance.

The first commitment period of the EU ETS commenced in January 2005, but allowances had then been traded on a forward basis since the spring of 2003. All trades were done OTC (outside exchanges) until Nord Pool opened its carbon market in February. Nord Pool was the first exchange going live with EUA allowances on 11 February 2005. Several exchanges followed during the spring of 2005.

6.2 EU ETS and thermal based electricity generation

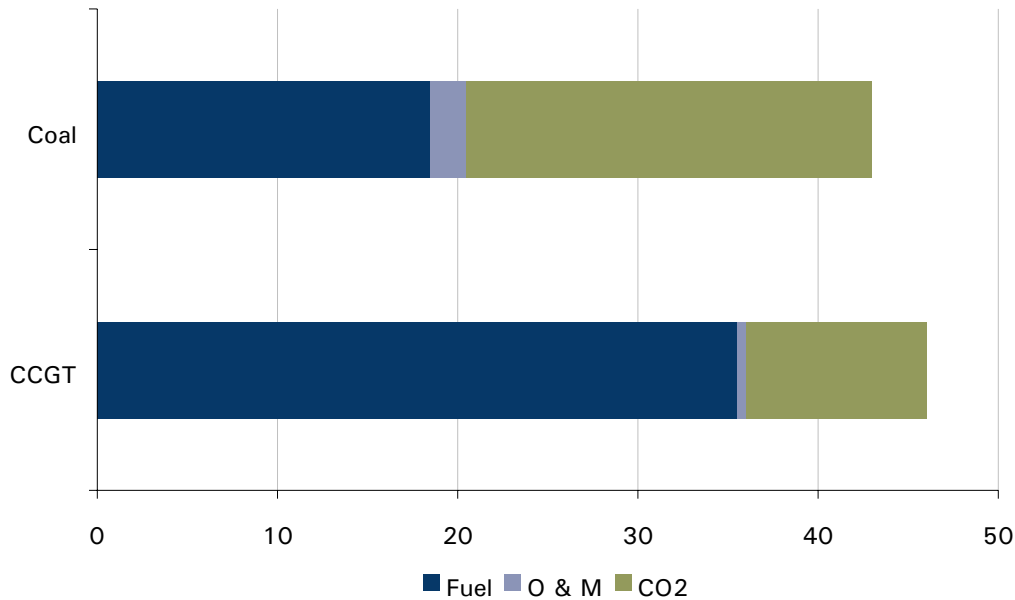
The introduction of the EU ETS has had significant impact on power prices across Europe. The theoretical background for this is that in a competitive environment where producers are maximising their profit, the cost of carbon should be factored into emitter's decision plan. Carbon cost can be regarded as an opportunity cost; it reflects the forgone value of the allowances used for generation that otherwise could have been sold. This is true irrespective of whether allowances have been provided for free or need to be purchased.

For a thermal power plant, the full CO₂ cost is added to the marginal production cost, thus the CO₂ price comes in addition to the cost of fuel and operation/maintenance (O & M). Figure 6.1 below shows how an EUA price of €25/t increases the variable production cost of a coal-fired power plant and a combined cycle gas turbine (CCGT). We have used coal and gas prices from 5 October 2005.

The EUA cost in €/MWh depends on the efficiency rate and the emission factor of the power plant. Efficiency rates for power plants vary, but in this example we have used 39 % and 53 % as standards for coal power plants and CCGTs, respectively. These plants emit around 0.9 tonne CO₂/MWh (coal) and 0.4 tonnes CO₂/MWh (CCGT).

This example explains that the introduction of EU ETS influences the electricity production costs in EU and also the merit order of the different production technologies. The coal power plant in the example is the cheapest technology if the CO₂ cost is disregarded. With an EUA price of €25/t included, the coal power plant is still the technology to prefer, however if the EUA price reaches €30/t, the CCGT plant will be the cheapest technology.

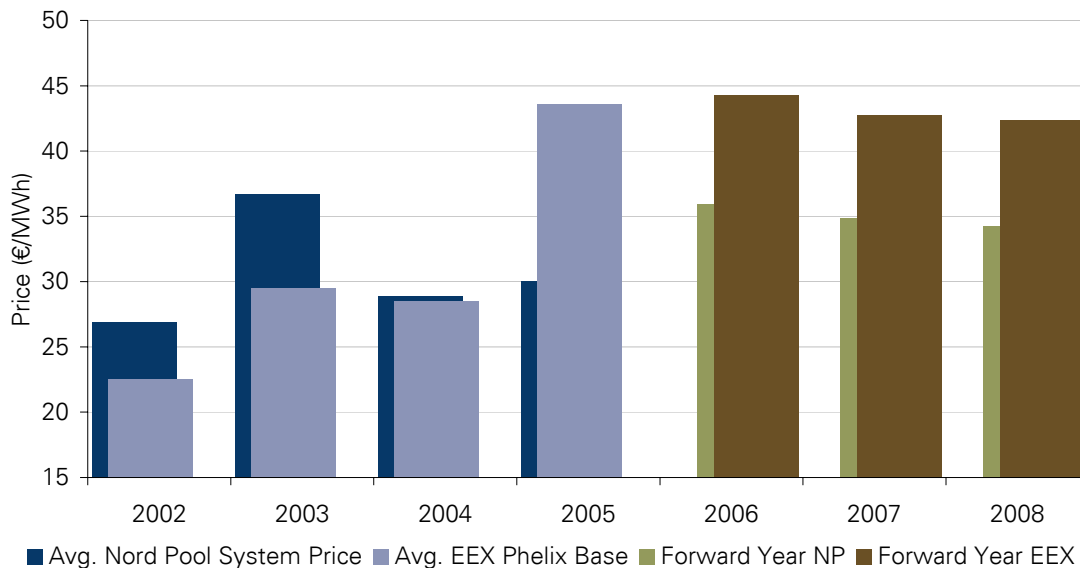
Fig 6.1 Short run marginal cost for a coal and gas fired power plant, EUA price of €25/t



The electricity wholesale prices seen in the German market in 2005 support these findings. Below we have presented the annual spot prices in the Nord Pool market and Germany (EEX) from 2002 and until 2005. From November 2005, the prices in the forward market have been used. The rise in the EEX spot prices in 2005 can to a large extent be attributed to the introduction of the EU ETS; the CO₂ cost has been added to the marginal production cost (thermal coal-fired plants dominate the German supply side). Coal prices have been falling since the middle of 2005 whilst at the same time gas prices have increased, due to the rising crude oil prices, widening the coal-to-gas differential. Even with increasing CO₂ prices, the price hasn't been high enough to make it profitable to switch from coal-fired power plants to CCGT's. The market expects the EEX price level in 2005 to persist in the 06-08 period.

The Nord Pool spot prices in 2005 seem to have been less affected by the EU ETS market. We will discuss this in depth in the following sections.

Fig 6.2 Average yearly spot prices Nord Pool and EEX (€/MWh)



Source: Nord Pool 25.10.05

6.3 Correlation between energy reservoir and Nord Pool spot prices

The supply side in the Nord Pool market consists of 51% hydro power, 13% nuclear power, 31% thermal power and 5% wind power/other renewables. This means that not more than 31% of the total installed capacity is exposed to the EU ETS market and the cap on CO₂ emissions. Included in the 31% are also Combined Heat and Power producers (CHP), where electricity a bi-product of the production of district heating.

The hydrological resources for hydro producers in the Nord Pool area can be defined as Total Energy Reservoir. This is the sum of water reservoirs and snow reservoirs in Norway and Sweden. Official water reservoir numbers are released weekly by the Norwegian Water Resources and Energy Directorate (NVE) in Norway and Svensk Energi in Sweden. Snow reservoirs are estimated during the winter season.

Normal water reservoir levels and snow reservoir levels are estimated by using 30 years of statistical data. In the graph below, we have plotted the weekly average NP spot price (left axis) and the deviation of the total energy reservoir from the normal (right axis), from 1996 until week 44 in 2005. Negative numbers on the right axis imply energy reservoirs below normal. When the NP spot price peaked in week 2 2003 at 750 NOK/MWh, the energy reservoir was 38 TWh lower than the seasonal normal, according to Point Carbon's models.

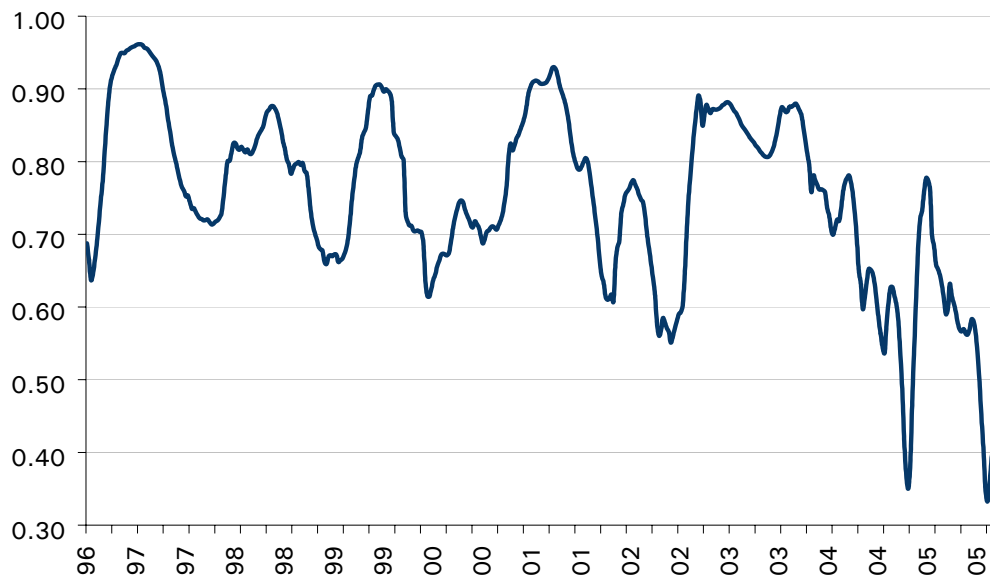
Fig 6.3 Total energy reservoir Norway and Sweden (deviation from normal) and Nord Pool spotprice. 1996-2005. TWh and NOK/MWh



There seems to be a break in the relationship between the total energy reservoir and spot prices from January 2005. The spot prices remained at the 200-250 NOK/MWh level, even when the energy reservoir improved substantially. As the chart shows, such energy reservoirs had previously resulted in spot prices in the 100-150 NOK/MWh area.

The correlation between total energy reservoir, deviation from normal, and spot prices is 0.85 in the period 1996-2004. Water and snow reservoirs below normal levels result in high prices, while the opposite is true when energy reservoirs are higher than the seasonal normal. In figure 6.4 below we have plotted the 52 weeks rolling correlation between the two quantities. The rolling correlation is between 0.6 and 0.95 from 1996-2004. For the period 2004-2005 the correlation dropped to 0.5 which means that only 25 % of the variations in the spot price can be explained by changes in energy reservoir. The increased correlation in the first weeks of 2005 is caused by some extremely wet weeks pushing spot prices down, while the dropping of the annualised correlation from week 7 05 to week 37 05 is mainly caused by rising CO₂ prices (more on this below), maintaining the spot price level. The correlation is increasing again in the autumn of 2005, probably caused by rather stable CO₂ prices and wet weather, the latter having a solid impact on spot prices as the water reservoirs are almost full at the time of writing.

Fig 6.4 52 weeks rolling correlation between NP spot price and Total energy reservoir (deviation from Normal)



6.4 Other reasons for higher than expected Nord Pool spot prices in 2005

In addition to the introduction of the EU ETS market, there are three main reasons for the uplift in NP spot prices in 2005: (1) Higher coal prices for thermal production, (2) increase in Nordic power consumption, and (3) rising German electricity prices.

The coal price has been significantly higher over the period 2004-2005 compared to 1996-2003. The marginal cost for a coal power plant has been 130-195 NOK/MWh for 04-05, disregarding the CO₂ premium and operating and maintenance costs. This limits the downside potential for the spot price. Even in a "wet year" there is not enough power generation capacity from hydro alone in the NP market and the coal power plants will not produce at spot prices below the marginal cost.

The consumption in the NP area has picked up this year, after the downturn caused by high prices in 2002-2003, and is now on the same level as in 2000, meaning well above the 1996-99 level. This results in more hours exposed to thermal power, since the installed capacity in hydro power has remained more or less unchanged since 1996. This also results in Norway being a net importer of power in a normal year from countries mainly dominated by thermal power.

The deregulation of the German market has resulted in more transparent prices for export from the NP area. The higher spot price level in Germany, caused by the added allowance cost, has also contributed to a rise in the NP spot price and the NP forward prices.

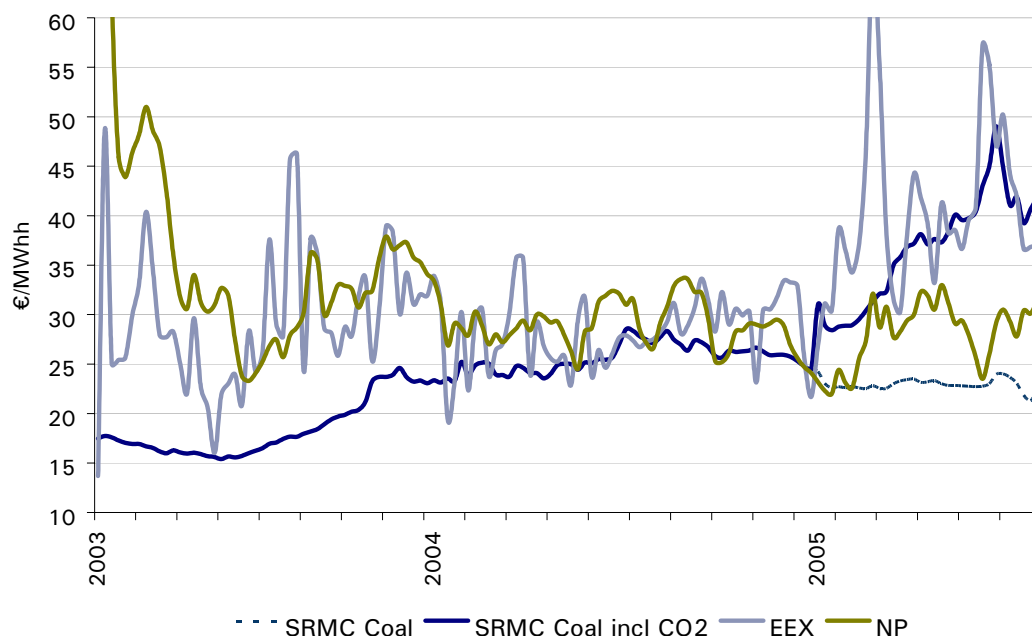
The spot prices are presented as nominal prices in the chart above. If we adjust the prices for inflation and convert them to fixed 1998 prices, the correlation between NP spot prices and total energy reservoir increases from 0.79 to 0.83 for the whole period (1996-05).

6.5 EU ETS and the Nord Pool market

As shown in the previous section, the NP spot price has remained at a high level in 2005, well above the level predicted if the relationship between total energy reservoir and NP spot price had persisted.

The introduction of the EU ETS has increased the short run marginal cost (SRMC) for thermal power production based on fossil fuels. In the beginning of 2005, SRMC was around €30/MWh for a typical coal power plant with efficiency rate of 39% (including fuel cost, CO₂ allowance and operating and maintenance costs). During the summer of 2005, SRMC reached a peak of €50/MWh, due to rapidly increasing CO₂ allowance prices.

Fig 6.5 Short run marginal cost coal, EEX base and NP spot price 2003-2005 (€/MWh)



The blue dotted line for 2005 in figure 6.5 above represents the SRMC for the coal plant with no carbon cost factored into the SRMC. The chart indicates that the carbon cost is clearly reflected

in the German spot price (EEX Base). However, the contribution margin for this coal-fired plant is far lower compared to 2003.

The NP spot price is considerably below the EEX Base and the coal SRMC (incl. CO₂). The reason for this is that 2005 has been a “wet year” in the Nord Pool market, with inflow to water reservoirs 28 TWh higher than normal in Norway and Sweden from January until November, giving rise to low spot prices. Since the total installed capacity in Norway, Sweden, Finland and Denmark is 51% hydro based, spot prices are highly influenced by precipitation amounts. In a “dry year” the NP spot price will have to increase considerably to result in net imports from the German market.

The percentage of power production with zero CO₂ emissions is high in the Nordic area. However, the EU ETS has implications for the hydro power producers too. In the Nordic region, the majority of the hydro producers employ the Sintef model called “Samkjøringsmodellen”. This model is used to define production volumes and assess the value of water reservoirs, i.e. estimate the so-called “water value”. The goal is to maximize profit when defining the spot bids for physical delivery in the next day’s 24-hour period. In the model, the cost of alternative production, typically thermal power production, is an exogenous variable. When the short run marginal cost of thermal power increases, this will in turn lift the water value.

6.6 Carbon price premium on Nord Pool spot prices

In the sections above we have found that the introduction of the EU ETS market has resulted in higher spot prices in both Germany and in the Nord Pool market. Since the NP market is less dominated by thermal power plant installations, which are directly impacted by the EU ETS, the carbon price premium is less obvious in this market compared with Germany.

Nevertheless, a relevant question is how much of the carbon allowance cost is currently reflected in the Nordic system price. The chart in the previous section told us that SRMC for coal was higher than the NP system price for the whole of 2005. This indicates that if coal-fired power plants in the Nordic market have added the full allowance cost to their marginal fuel cost in 2005, they will have had a negative margin for the whole year.

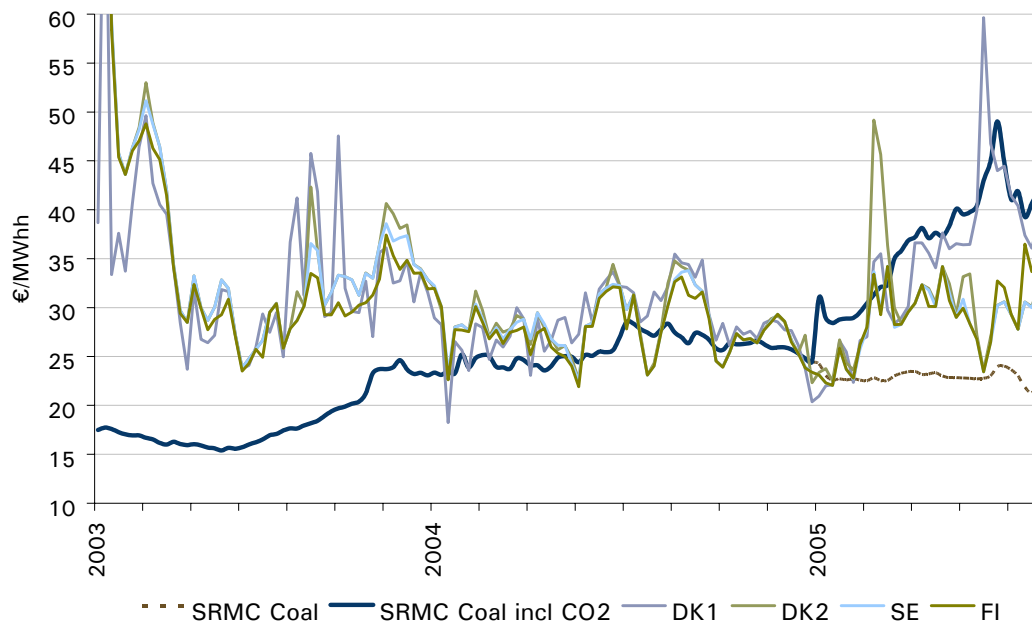
However, more relevant than the system price for the producers are the area prices. These are spot prices in the different parts of the NP market calculated with exchange constraints between areas included.

Figure 6.6 below gives a somewhat more balanced picture. The area price in Western Denmark (DK1) is much closer to the SRMC for coal, with the full allowance cost added. The rather close link to the German electricity market is one explanation for this, in addition to the domination of coal power in DK1.

In Eastern Denmark (DK2) there are also short periods with area prices close to or above the SRMC for coal, however from week 12 2005 the DK2 price, together with the Swedish (SE) and Finnish (FI) price, lies considerably below the SRMC for coal. There are two main reasons for

this: (1) Hydro power is dominating for the particular period, displacing thermal power, (2) the full allowance cost is not added to the marginal cost.

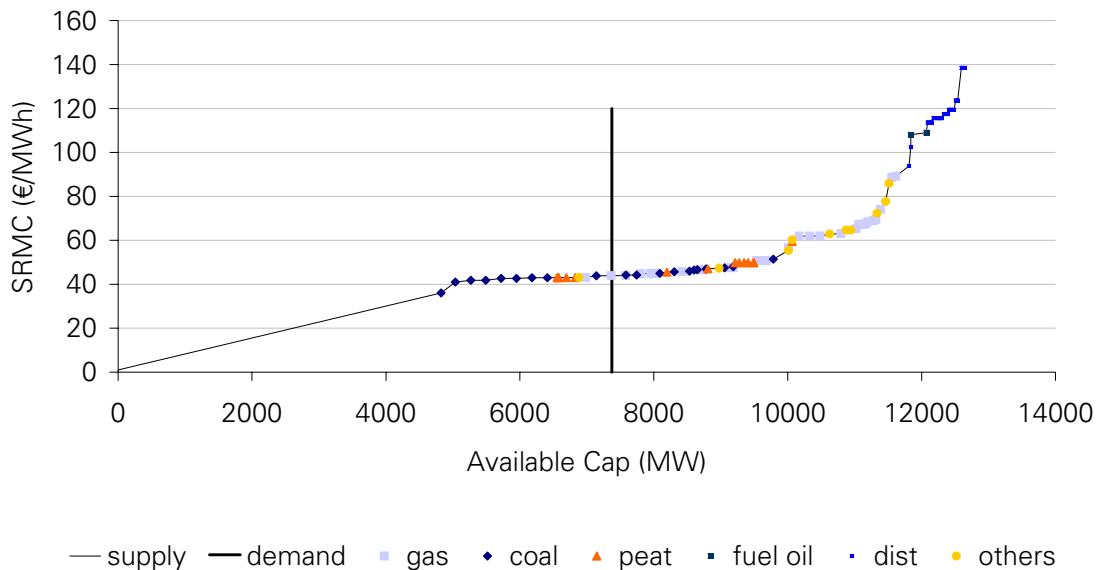
Fig 6.6 Short run marginal cost coal and NP area spot prices 2003-2005 (€/MWh)



We have decided to look at the market equilibrium price in the Finnish power system for a given hour in 2005 to see if we can learn more about the carbon price premium on NP spot prices. For this purpose Point Carbon's Stack model is used with detailed data for each thermal power plant in Finland. The marginal cost for each power plant based on type of fuel, efficiency rate, emission factor and operating and maintenance cost is computed. Then the data is stacked according to increasing marginal cost, and we get a theoretical supply curve. The market clearing price is where the demand (assumed price independent for the single hour) intersects the supply curve. Looking at the production in hour 12 on Friday 29 September, we get the following data:

- Total production volume: 7374 MW
- Hydro power: 1621 MW
- Nuclear power: 2660 MW
- Thermal power: 7374 MW-1621 MW- 2660 MW = 3093 MW

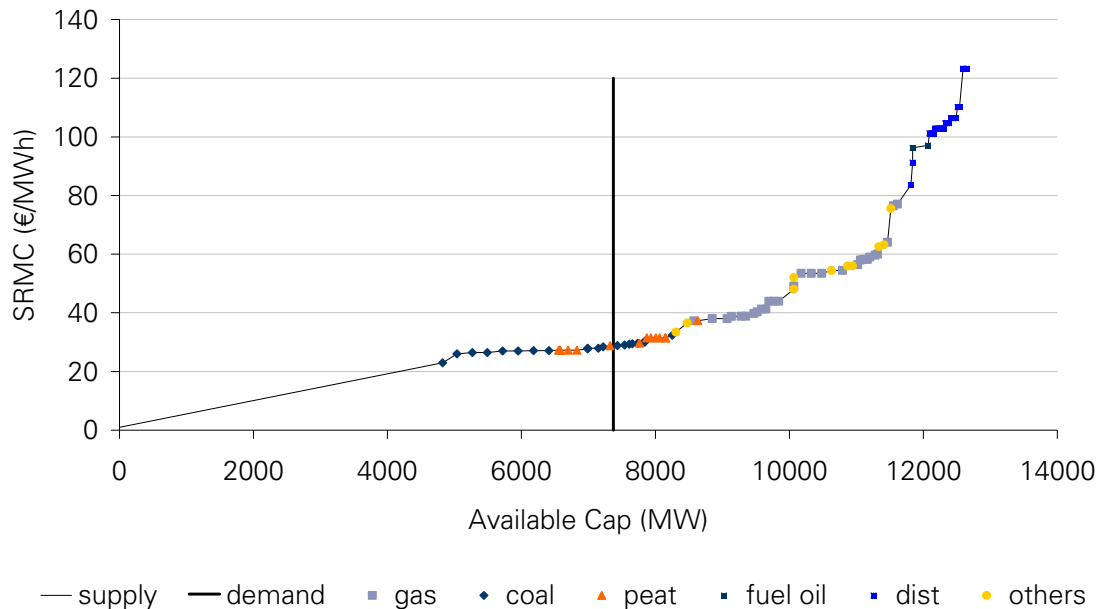
Fig 6.7 The Finnish stack including CO₂ costs at €22/t



In this analysis we have made the assumption that biddings for this hour are made on the basis of marginal costs alone, which is in general not true. Combined heat and power producers (CHP) often have production obligations, and will produce power whatever the price may be, while average prices for several consecutive hours are decisive for thermal power plants. However, from this theoretical point of view, and with a CO₂ price of €22/t, we get a market clearing price around €44/MWh in hour 12. The fuel prices used are front month prices as of Thursday 28 September.

The actual Finnish area price for hour 12 was €29/MWh, and this was in fact the average price for the day as well. This is the price we obtain by adding an allowance cost of some €7/t to the fuel cost (see below). This specific example gives a carbon price premium of around 30%. It is possible however that some CHPs operate with much lower marginal costs than our theoretical calculations show, but this accounts for only a small part of the total production capacity, and will only increase the carbon price premium slightly. Nevertheless, this example illustrates clearly that not all of the current CO₂ allowance cost is reflected in the Nordic system price.

Fig 6.8 The Finnish stack including CO₂ costs at €7/t



6.7 Other assessments of the influence of carbon on Nordic spot prices

Amongst players in the Nordic power market, there seems to be a general opinion that the CO₂ allowance cost could be regarded as an opportunity cost, but the opinions differ as to the extent to which this cost is priced in. In the specialist press this factor has been estimated to be somewhere in the range of 30%-70%. In Aftenposten 19 August this year, Statkraft director Eli Skrøvset claimed that "a carbon price of around €20/t increases the system price by around 50-100 NOK", which equals a factor somewhere between 30 and 65 per cent, given the allowance price level (€22-23/t) at that time.

The theory of allowance price is however questioned by researcher Knut Einar Rosendahl in Statistics Norway. He points out several features of the EU emissions trading scheme to back this. Firstly, the fact that most emitters receive 95% of the allocations needed for free means that, from a cost-benefit point of view, the pricing factor should be closer to 5% than 100%, and the marginal cost will not be reflected in the system price. Secondly, as future allocation at least in some countries depends on actual emissions today, there is no economic incentive to reduce production and sell allowances.

6.8 Conclusions

The EU ETS market has resulted in higher spot prices both in Germany and in the Nord Pool market. Since the NP market is less dominated by thermal power installations included in the EU ETS, the allowance cost is far from being fully incorporated in the NP spot price. Based on the rather short time span with the EU ETS market in place, and bearing in mind that 2005 has been a very “wet year”, we estimate the carbon price premium on NP spot prices to be in the order of 30-60 %. In a normal rainfall year, we would expect the carbon price premium on NP spot prices to be at the higher end of this range given a higher level of generation from thermal sources.

7. Price formation for forward electricity contracts prior to 2005

In this section we intend to give an account of price formation in the Nordic forward electricity market prior to the introduction of the EU ETS. We have focused on the market situation in 2004, when emission allowances were already a relevant issue and trading on a formal basis took place, in order to make an assessment of whether carbon costs were included in the price. We start by an overview of the Nord Pool financial market.

7.1 Background

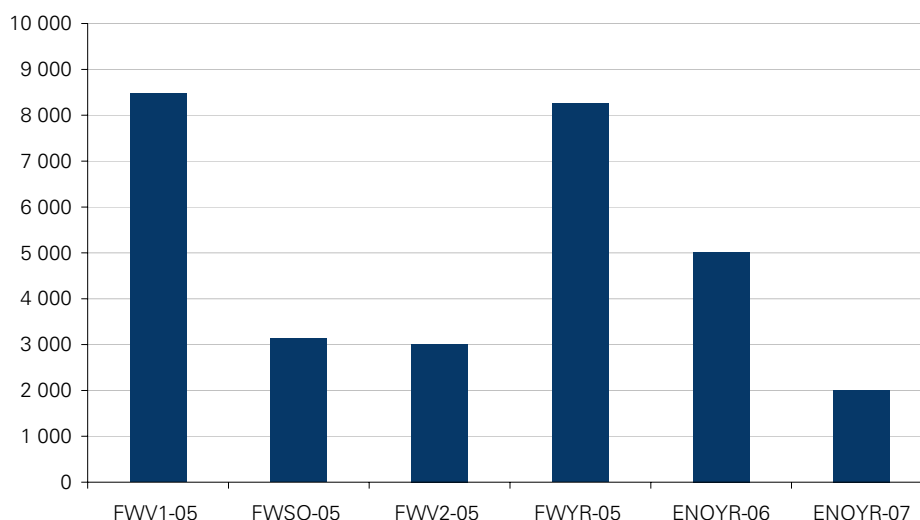
The long-term forward contracts listed in the Nord Pool financial electricity market are the contracts for quarters two years ahead (seasons up until 2005) and annual contracts three years ahead. By the end of 2004, these were:

- FWW1-05, FWSO-05, FWW2-05 (season contracts)
- ENOQ1-06, ENOQ2-06, ENOQ3-06, ENOQ4-06 (quarter contracts)
- FWYR-05, ENOYR-06, ENOYR-07 (annual contracts)

Each contract in the financial market is traded up until the last trading day before the start of its delivery period, and for the seasonal contracts these are January-April (V1), May-September (SO) and October-December (V2). Delivery price for a contract is the average price over the period, without regard to actual volumes.

All forward contracts with delivery date past 31 December 2005 are listed in €/MWh, while contracts with delivery date prior to this date were listed in NOK/MWh. In addition to the change in trading currency, the system price area will from 1 January 2006 include the two Danish regions in addition to Norway, Sweden and Finland, hence the new classification and naming of products.

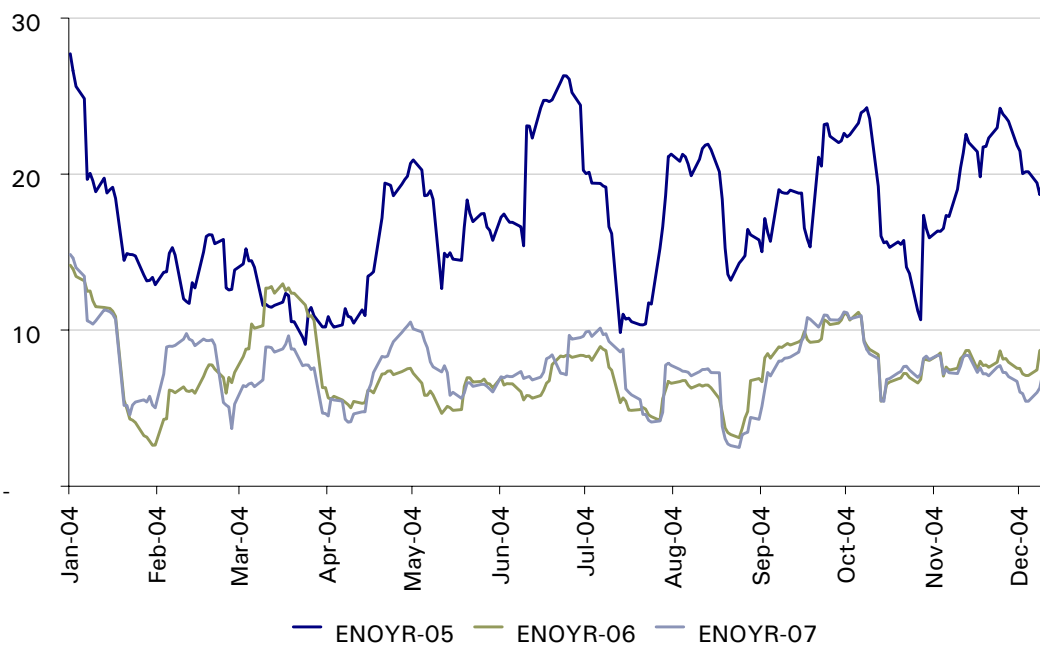
Fig 7.1 Open interest volumes for forward contracts December 2004 (MW)



The most liquid product in the Nord Pool financial market is the nearest seasonal (or quarterly from 2006) forward contract. The chart above shows the open interest volumes for contracts for the nearest seasons and years as of December 2004. Open interest for a specific contract is the net balance of open positions, as registered by Nord Pool Clearing, and is the best indicator for actual interest in a financial contract. We stress that the open interest for the annual contract of 2005 is at the same level as the nearest season (V1), a prevalent feature at the end of each year.

Long-term forward contracts tend to be strongly correlated, but with higher volatility for front products, i.e. contracts for the nearest quarters and years. In 2004, the ENOYR-06 contract had an 89% correlation with the FWYR-05 contract, while the corresponding figure for the ENOYR-07 contract was 88%. This shows that the most liquid and volatile contracts points out the direction for the others. In 2004 FWYR-05 was driven by fundamental signals and gave the direction to follow for the other yearly contracts. Interestingly, we note that the correlation between the '06 and '07 contracts was nearly perfect at 99%.

Fig 7.2 Historical volatility for yearly forward contracts 2004



During most of 2004, the forward curve was in backwardation, which is the technical way of saying that short term price expectations exceed those on a longer term. This corresponds well with the rather poor hydrological situation the Nordic power market experienced during most of 2004, as deviations in energy reservoirs obviously have a larger impact on the system price in the shorter term, since energy reservoirs are expected to approach normal levels over time. Towards the end of the year, when the hydrological situation in Norway and Sweden improved, the front

product slipped down. The forward curve then moved into contango, which is the opposite situation of backwardation, i.e. prices are expected to increase in the longer term.

Fig 7.3 Yearly forwards 2004 (€/MWh)



Price formation for the nearest seasonal forwards in the Nord Pool financial market is a complex issue, but as we have already learned one of the key price drivers is traditionally the forecasted energy reservoir (hydrological balance), which is a good benchmark for where the system price is heading. Important for price setting is also whether spot price turns out in accordance with market expectations. However, this is strongly correlated with other components in the price setting, like weather, commodity prices and exchange prices, and it is by no means obvious how to separate the price impacts of each component.

The situation in the Nordic power market in 2004 was characterised by a poor, but slowly improving hydrological balance throughout most of the year. The market naturally expected the situation to gradually move towards normality over time. However, hydrological balance was negative for quite a while, and the system price remained firm during most of the spring and summer, except for short periods with high unregulated hydro production. As a result, forward prices strengthened despite hydrology improvement, making it difficult to quantify the hydrological impact.

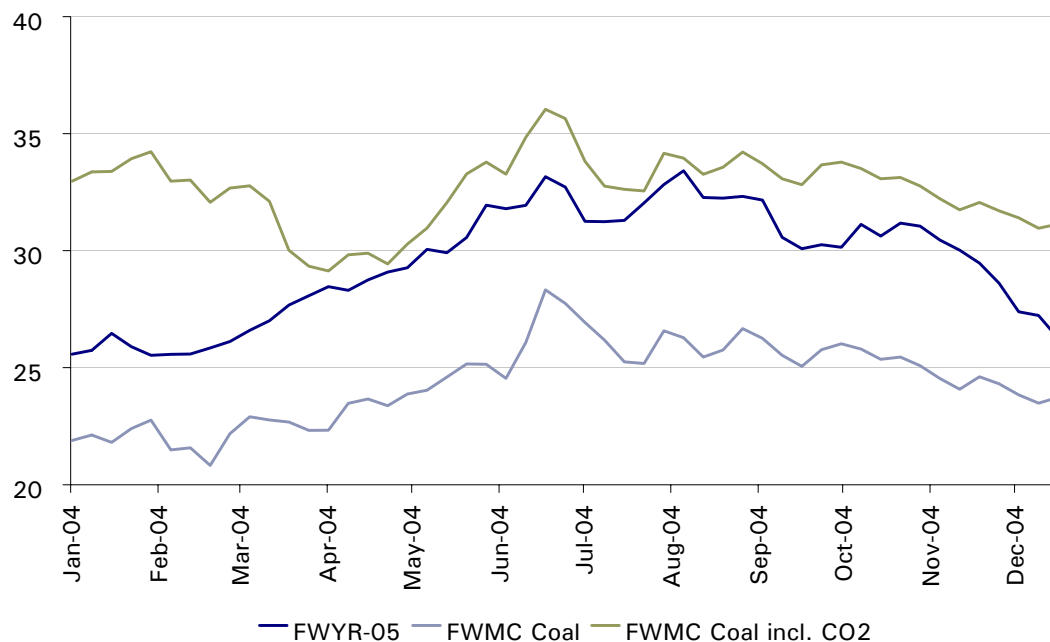
The yearly forwards often have a high degree of correlation with the nearest forward, but with lower volatility. However, since weather impact is rather insignificant in a longer perspective, other factors, like fuel prices and German forward prices, play an important part in price formation for long-term contracts. In 2004, week-on-week changes in the nearest seasonal forward and in the FWYR-05 contract had a correlation as strong as 92%. We consider the

FWYR-05 contract to be the best benchmark contract for understanding the price formation in the Nordic forward market. The contract is less sensitive to short term fluctuations in spot price and weather forecasts than the nearest seasonal forward. Rather, it reflects the underlying trends in the market. Compared to the yearly contracts two and three years ahead, it has higher liquidity and interest. In short, it is the most representative of the yearly contracts.

7.2 Key price drivers

In 2004, the main price driver for the FWYR-05 contract was forward prices in the European coal market. In the graph below, calculated forward marginal cost for a standard coal-fired power plant (with efficiency rate 39%), given closing price for the 2005 annual coal contract and unit costs for such a plant, is plotted together with the FWYR-05 contract. In addition, we have plotted the marginal cost with the CO₂ allowances added on top.

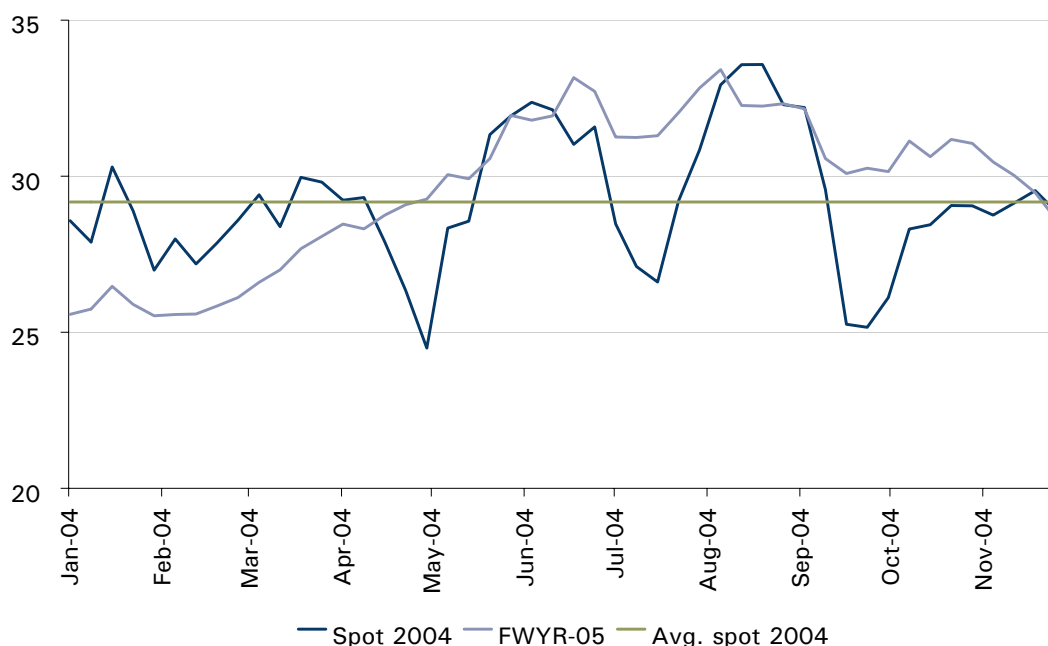
Fig7.4 Forward power price and forward marginal cost (€/MWh)



In 2004, the correlation between the 2005 forward marginal cost for coal (CO₂ excluded) and the Nord Pool contract was as strong as 91%, based on weekly averages of closing prices in both markets. No other identifiable factor shows a similarly strong relation to the Nord Pool price in this period overall. If we add the CO₂ allowance cost to the margin however, the correlation decreases to only 40%. This is the outcome with a 100% inclusion of the allowance price, but the correlation decreases even when adding only a very low percentage of the allowance cost. This is in part a consequence of the market situation during the first six months of 2004, where both power and coal prices increased, while CO₂ allowance prices went south. Nevertheless, it indicates that the allowance cost was not included in the forward market in 2004.

If CO₂ prices were included in the forward price, it is reasonable to expect a certain price rise from the spot price level in 2004. But as shown in figure 7.5 below this was not the case. Keep in mind that we had a poorer than normal hydrological situation giving rather firm spot prices early in 2004, and that this was not expected to last well into 2005. But even towards the end of the year, when hydrological levels improved significantly, YR-05 prices were not much higher than the spot price level. In fact, compared to the actual yearly average spot price in 2004, the expectations for 2005 at the turn of the year were lower. In addition, the forward curve was in backwardation most of the year, meaning that prices in 2006 and 2007 were expected to be even lower despite the introduction of the EU ETS.

Fig 7.5 NP Spot price and FWYR-05 2004 (€/MWh)

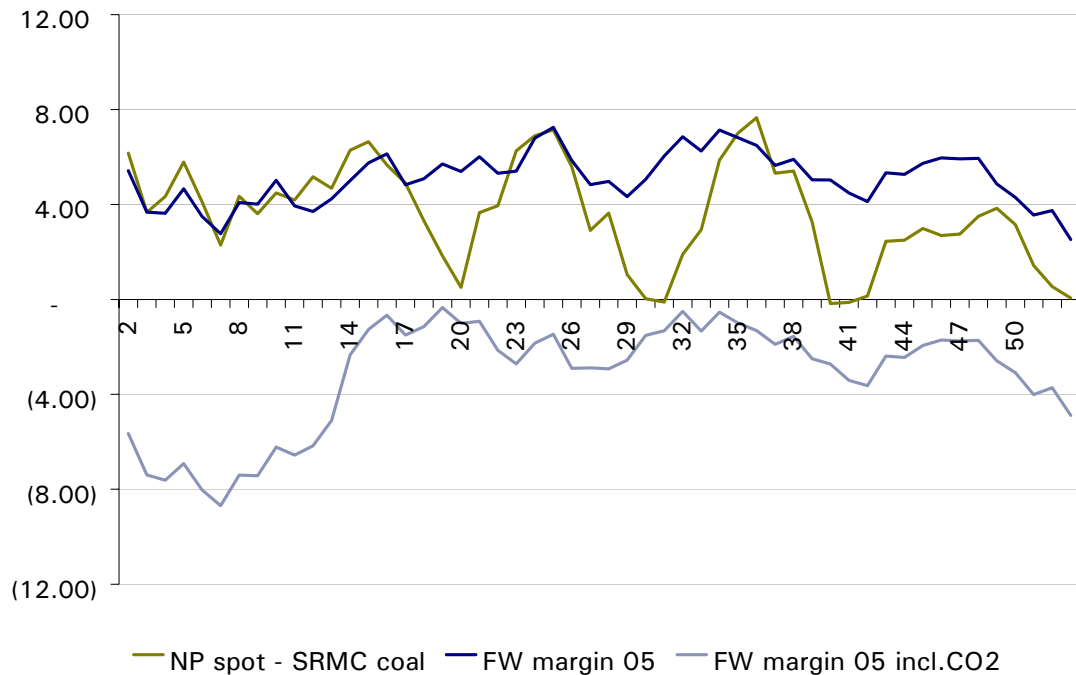


In order to get to gain further insight, we have looked at the operational margin (dark spread) for coal-fired power plants in the Nordic power market. By this we mean the difference between the Nord Pool system price and the short run marginal cost for a standard coal-fired power plant as defined earlier, given coal prices in the European spot market. Coal-fired power plants are inflexible in general; they often have large start up costs and have to produce in both peak and off-peak periods. Thus, we have used weekly average prices in our analysis.

In 2004, this margin was positive throughout the year (see figure 7.6), even in weeks when the system price was put under pressure by a large unregulated hydro production in Norway and/or Sweden. The average margin in 2004 was around €3-4/MWh. For comparison forward margins for 2005 are shown, i.e. the same difference calculated with 2005 forward coal and power prices. It is important to note that this is expectations for the yearly average in 2005, while the spot margin is a weekly average. All the same, we observe that the forward margin corresponds

much better with the level of the spot margin when CO₂ is not included. The forward margin for 2005 without CO₂ varied between €2.5/MWh and €7.5/MWh, while with allowance costs included it was negative throughout the year. This does not prove that allowance costs were not added at all, but it does point to the fact that they were added, it was to a rather low degree, and probably a lesser degree than we have seen in the market so far.

Fig 7.6 Operational margin (dark spread) coal-fired power plants (€/MWh)



Another important price driver for the FWYR-05 contract in 2004 was the 2005 annual contract on the German power exchange (EEX). Price development for these two contracts showed a correlation of around 71%. The EEX market is more dependent on coal-fired power plants, and it is reasonable to expect a higher coal and carbon impact. There are indications in our data for 2004 that the CO₂ allowance prices may have been priced in to some degree in the EEX forwards, but a more thorough investigation would be necessary to say anything conclusive, and this is not within the scope of this report.

A similar analysis for the ENOYR-06 contract hints in the same direction, while liquidity for 2007 contracts was too low both in power and coal markets to conclude.

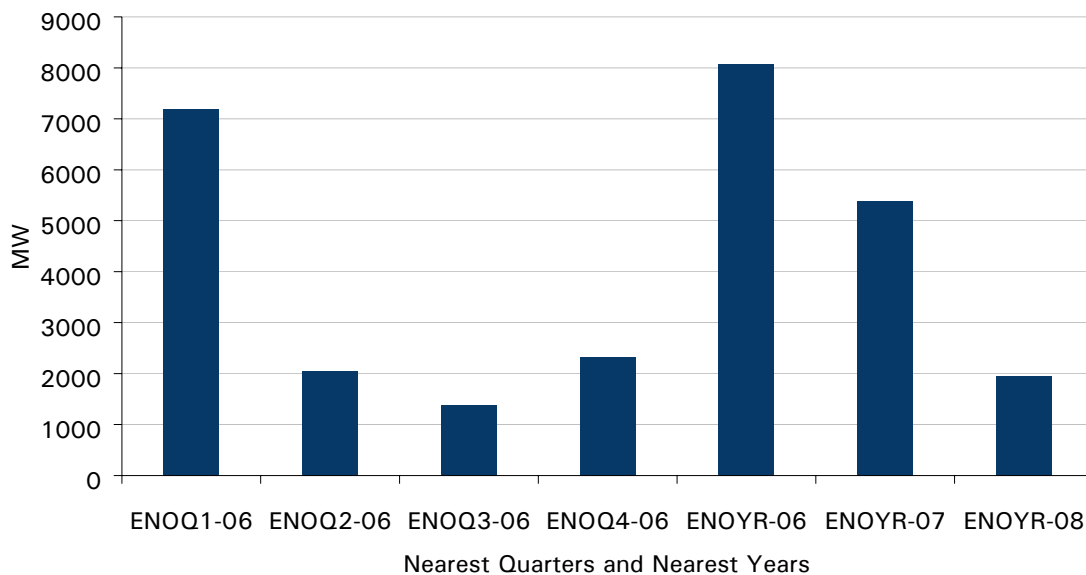
7.3 Conclusions

In 2004, price developments for forward contracts for 2005-07 did not bear any apparent link to changes in CO₂ allowance prices, and no significant price lift seems to have been expected due to the introduction of the EU ETS.

8. Assessment of current long-term forward contracts

The long-term forward contracts listed in the financial electricity market at Nord Pool as of October 2005 are quarter contracts for 2006 and -07, and annual contracts for 2006-08. All the prices for the long-term forward contracts are now listed in €/MWh. Figure 8.1 shows the open interest volumes for the nearest quarters and annual contracts as of October 2005.

Fig 8.1 Open interest volumes for forward contracts quarters and years October 2005

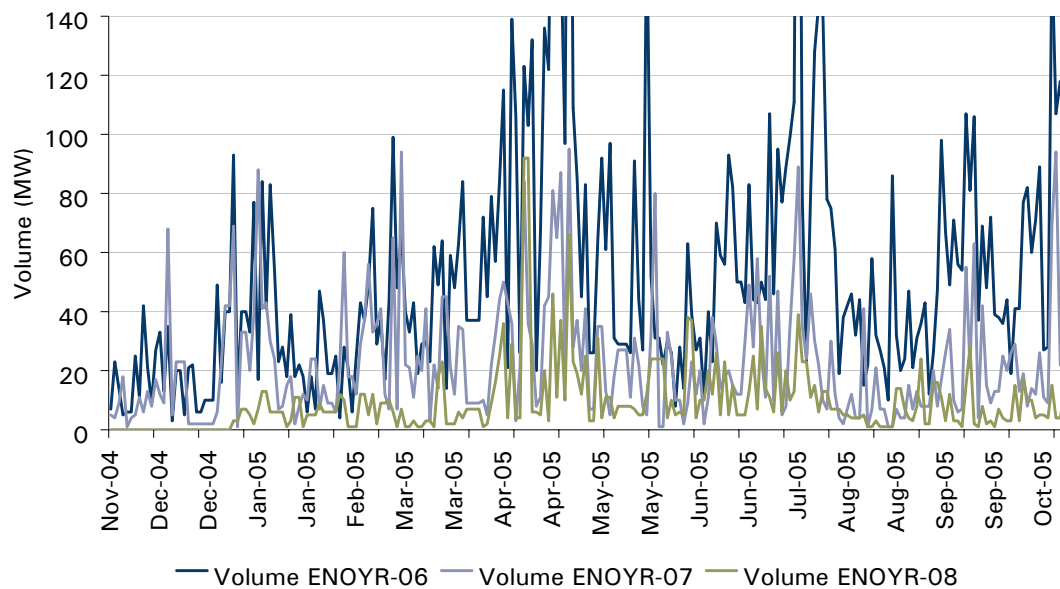


Source: Nord Pool

The traded volumes are clearly highest for the nearest contracts. The volumes for the quarters beyond 2006 are not graphed, but they are all below 1000 MW. The pattern is typical for the behaviour of the long-term forward contracts. The graph below shows the daily liquidity of the current annual contracts from November 2004 to October 2005.

The nearest year is clearly the most liquid contract and the daily volumes for the contract three years ahead are lower. The same is true for the volatility of the annual contracts. The volatility is highest for the nearest year and decreases for the following years.

Fig 8.2 Daily trading volumes for the forward annual contracts at Nord Pool



8.1 Recent price development for long-term forward

The trend for the long-term forward contract in the financial market at Nord Pool was bearish (decreasing) at the end of 2004 and up to mid-January 2005. The ENOYR-06 contract closed as low as €25.3/MWh on 12 January, the lowest closing price for this contract since August 2003. From mid-January until mid-February, the market was ranging and the daily closing values for the ENOYR-06 remained below €27/MWh. Since then there has been a steady bullish (rising) trend in the market.

The annual contracts in the financial market at Nord Pool are closely linked and the current contract that is driving the others is ENOYR-06. The table below shows that the correlation is near perfect for the daily closing prices for the three annual products at Nord Pool. In fact, they are stronger correlated than the corresponding contracts were in 2004. To some extent, this can be explained by the lack of currency risk between the products, but probably more importantly they are now driven by the same fundamental signal: changes in CO₂ allowance prices.

Fig 8.3 Closing prices for the annual contracts at Nord Pool

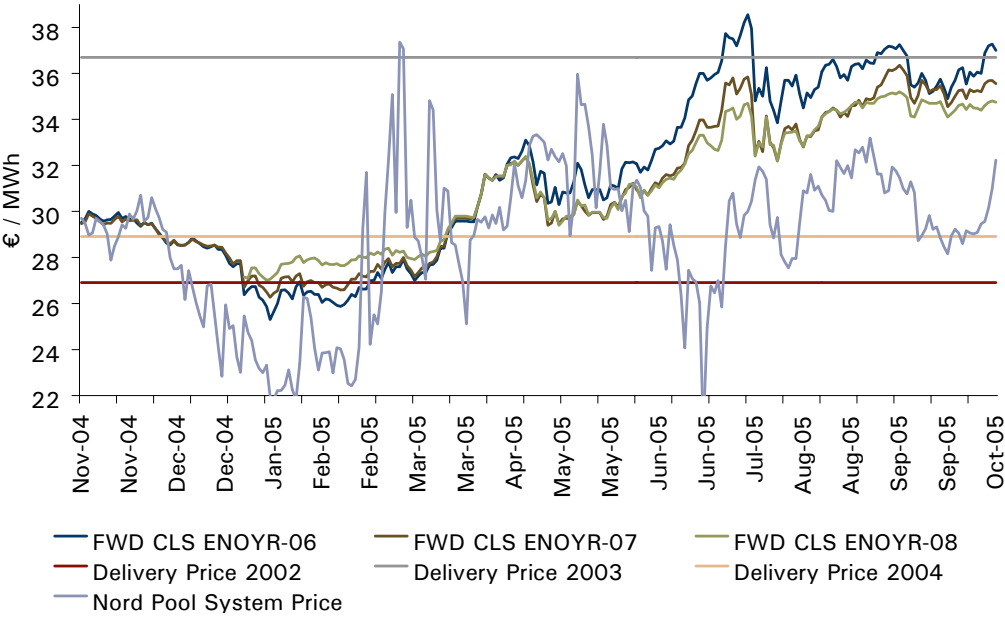


Fig 8.4 Historical volatility for the annual contracts at Nord Pool



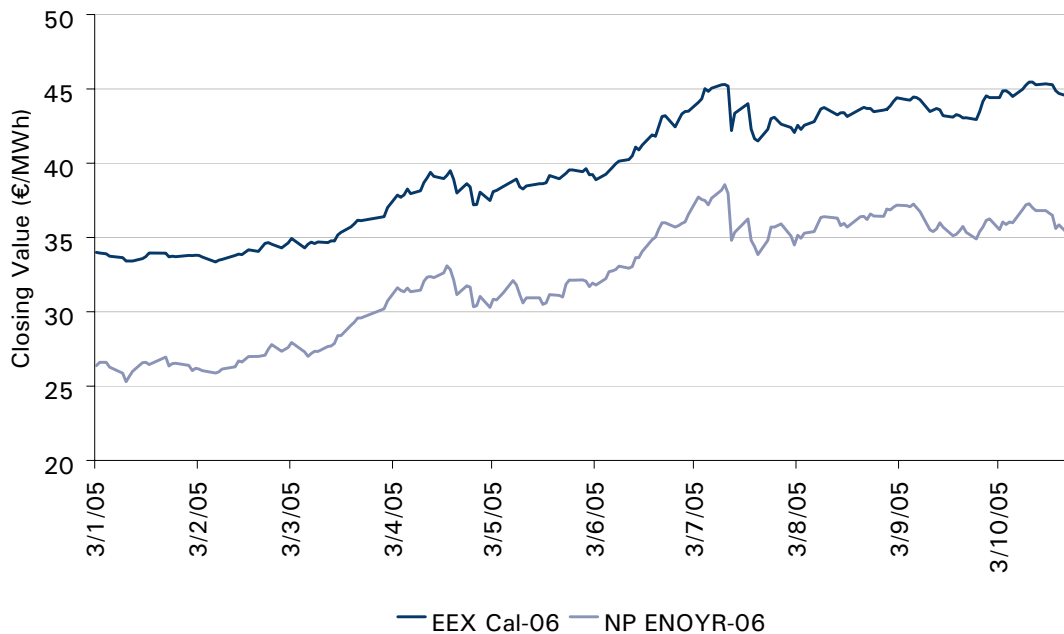
Contracts	Correlation
ENOYR-06 vs. ENOYR-07	0.99
ENOYR-06 vs. ENOYR-08	0.98
ENOYR-07 vs. ENOYR-08	0.99

at the period 02.11.04 - 13.10.05, the correlation between the daily closing values of ENOYR-06 and the Nord Pool system price is as low as 0.45.

Daily closing price ENOYR-06 vs. Nord Pool system price	
Period	Correlation
02.11.04 -18.02.05	0.82
02.11.04 - 01.03.05	0.73
02.11.04 – 13.10.05	0.45

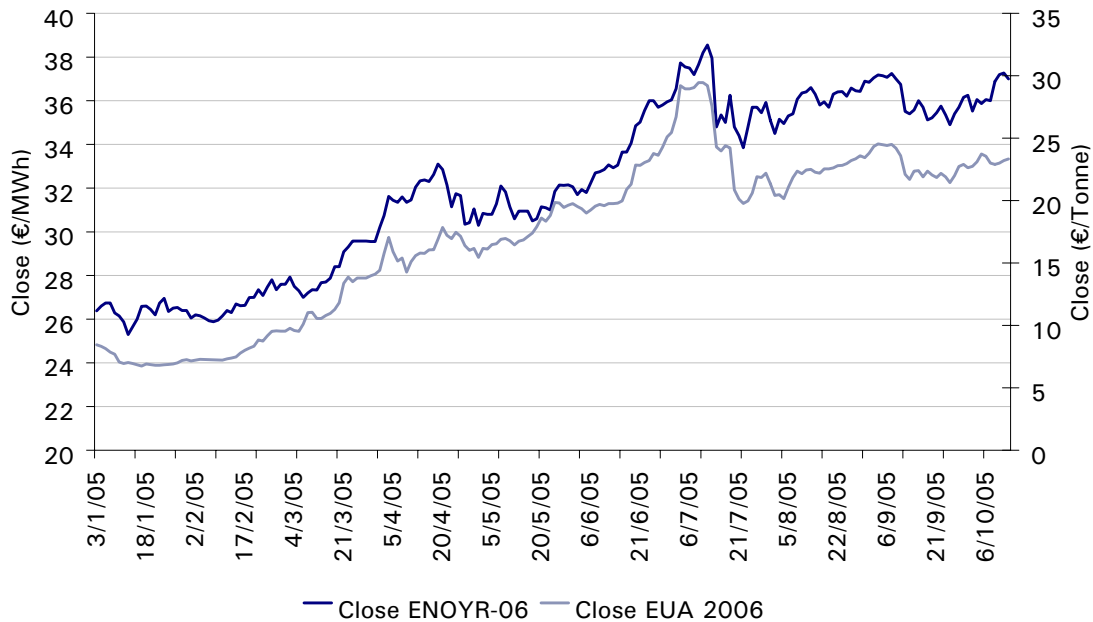
The prices in the forward market climbed steadily in the last half of February while the system price weakened. This happened at the same time as Nord Pool opened its carbon market. The price of EUA for 2005 delivery climbed from around €7/t in the beginning of February to around €9.50/t in the beginning of March. During the spring of 2005 the focus in the market was gradually shifted from weather forecasts and hydrological balance to CO₂ allowance prices and the German forward market. The correlation between the annual contracts in the German and Nordic forward market has increased from January until October 2005. For the whole period from 1 January 2005 until 30 September 2005, the correlation between the daily closing prices of the ENOYR-06 contract and the EEX Cal-06 contract has been 0.99 (nearly perfect).

Fig 8.6 Daily closing prices ENOYR-06 vs. Cal-06



In 2005, there has been a strong link between the German forward prices and the development in EUA. The correlation between the daily closing prices of ENOYR-06 contract and the EUA for 2006 delivery for the same period as above, is 0,97.

Fig 8.7 Daily closing prices ENOYR-06 vs.EUA 2006



One might wonder why such a strong correlation between the German Cal-06 and the Nord Pool ENOYR-06 exists when the spot prices so far in 2005 in the two markets are not correlated. The explanation is that even though the daily variations in the spot prices in the German and Nordic power markets do not correlate in 2005, this is not the same as saying that the average yearly spot prices will not be linked. The strong correlation between ENOYR-06 and Cal-06 reflects that the market participants in the Nordic area either expect the power price level in Germany to influence the average spot level in the Nord Pool area or the same external factors be decisive for spot prices in both markets. The variation in the spot from day to day is a function of local temperatures, wind power supply, holidays, water flow, outages etc. These variables are clearly not necessarily correlated across market borders.

As shown in previous chapters, the introduction of the EU ETS has created a stronger link between the Nordic power prices and the fuel prices. Fuel prices are one of the main price drivers in the German market. The price formation of carbon and power happens in a complex interplay between the two markets. Given the high dynamism of the markets it is still too early to say how this interaction will develop in the longer term. Some facts argue in favor of even stronger links between the Nordic and German power markets in the future, as we will now argue.

From 2006 the Danish market will be fully integrated with the rest of the Nord Pool area. Currently prices in Western Denmark are closer to the German market than the prices in the rest of the Nordic area. In addition, Nord Pool is focusing its efforts on integrating the Nordic and the Continental European power markets further. In October 2005 – KONTEK – a new bidding area

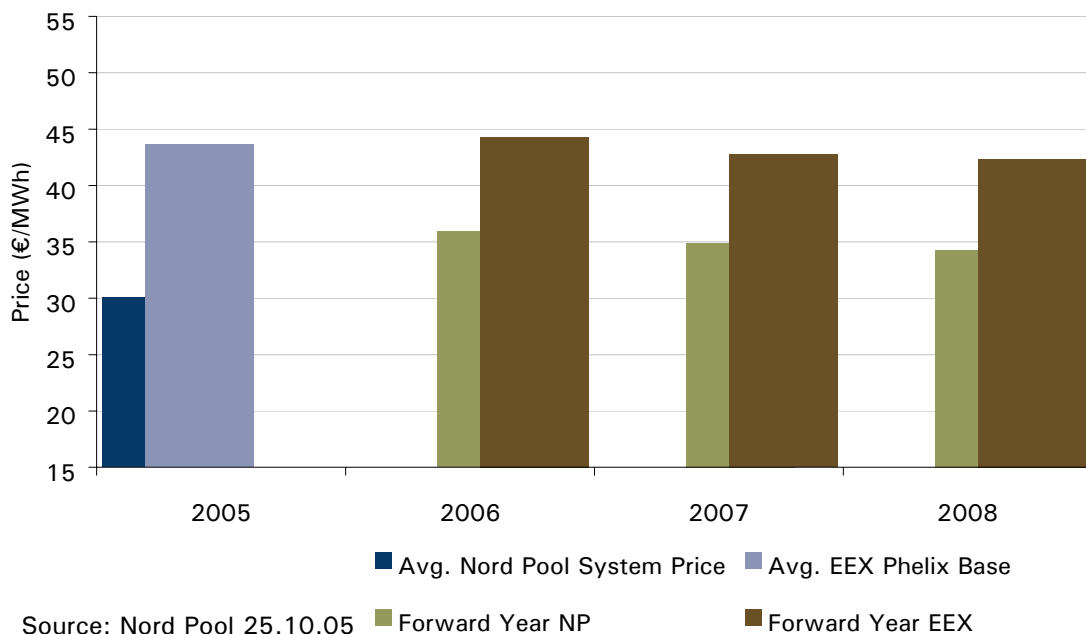
opened in Germany. KONTEK is the Vattenfall Europe Transmission Control area in Northern Germany and gives Nord Pool Spot customers access to spot trading in this area. This assures that the power on the Danish-German borders flows from the area with the lower to the higher price.

Underlying trends in power demand in the Nordic region should be accounted for in long-term price assessments. There are indications that the consumption increases faster than added renewable energy production in the Nordic region. The 52 weeks “rolling” temperature adjusted consumption growth in both Norway and Sweden is positive, meaning that the consumption the last 52 weeks is higher than in the previous 52 weeks. This greatly outweighs the negative trend in Finland. One possible consequence of higher consumption without added emission free production, is that we will have a larger percentage of hours during the year with Nordic fossil fuel plants (mostly coal) working on the margin.

8.2 Carbon cost pricing in long-term forward contracts

Figure 8.8 shows that the market expects a significantly higher average price in the Nord Pool area in 2006 compared with 2005, which might indicate that more of the carbon cost will be priced into the system price in the future.

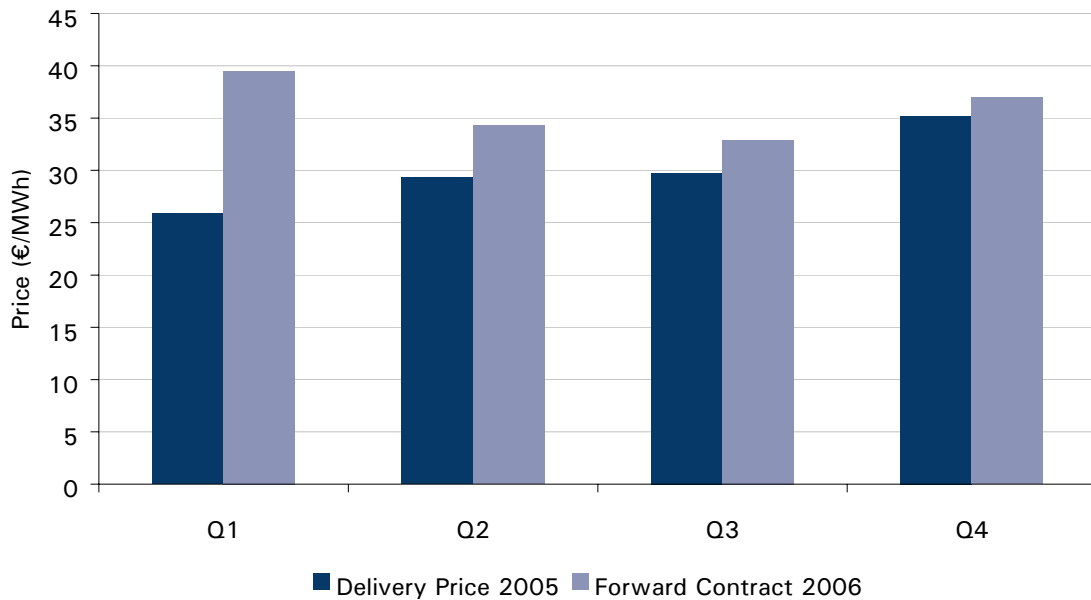
Fig 8.8 Average yearly spot prices Nord Pool and EEX



Looking more closely at the forward prices for the quarters, we see in figure 8.9 that the difference between 2005 and 2006 decreases as the year progresses. The forward price for Q4-06 is only €1.8/MWh higher than the expected delivery price for the fourth quarter of 2005. At

the other end of the scale, the difference between the first quarter in 2005 and 2006 is €14/MWh. The seasonal price variations reflected in the market expectations for 2006 are more typical than the pattern seen in 2005.

Fig 8.9 Daily Nord Pool quarters contracts



8.3 Conclusions

Our analysis indicates that the forward market only reflects the current spot level and does not factor in a substantially higher CO₂ cost in 2006. Another argument pointing in the same direction is the fact that our seasonal model estimated with data from 2000 up to week 20 in 2005 gives a higher price for the year 2006 than the current forward price for the 2006 contract.

Annex 1: Description of used models

To predict future power prices, we have employed two different models.

- A bottom up level called The Stack Model
- A top down model called The Future Price Model

The two models are complementary forecasting tools.

The Stack Model is used to find the market equilibrium on an hourly or annual basis with detailed description of the power system in question. The model can be used to analyse power balance in the long run.

The Future Price Model is a statistical model used to forecast seasonal patterns and give average weekly delivery prices for a time horizon of up to 2 years.

MODEL	Strengths	Weaknesses
The Future Price Model	<p>Easy to implement and re-estimate.</p> <p>Gives good seasonal forecasts for a limited time horizon</p>	<p>The model has clear limitations when it comes to accounting for future structural changes in the power system</p> <p>The model should not be used beyond a time horizon of about 2 years.</p>
The Stack Model	<p>Structural changes in the power system can be accounted for.</p>	<p>Does not give good forecasts of weekly delivery prices. Difficult and very time consuming to prepare input data if the model is to be run with hourly resolution to get the seasonal patterns.</p>

The Stack Model

Point Carbon has carefully collected detailed information about each power plant in the Nord Pool area. Available nuclear, hydro and wind power is added along with the information about each thermal power plant.

The data includes

- Type of fuel

- Efficiency rate
- Emission factor
- Operational and maintenance cost

The stack can be used on an hourly basis with installed capacity or to look at annualized supply and demand data. Based on computed marginal cost for a given fuel price level, the data is stacked according to increasing marginal cost.

Given the annualized or hourly supply of the various technologies and the relevant demand, the market clearing price is found. An underlying assumption here is that the market is transparent and fully competitive.

The Future Price Model

The Future Price Model is an OLS statistical regression model estimated on weekly data from week 1 2000 to week 40 2005. The model is used to forecast spot prices 2 years ahead:

- Main variables
 - Total energy reservoir
 - Precipitation energy
 - Water flow
 - Consumption
 - Coal prices
 - CO₂ Allowance price