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Counterproductive environmental policies: Long term versus short term substitution effects of gas in a liberalised electricity market

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Abstract

In Norway, the environmental impact of building gas power in a liberalised market has been the main controversy for over a decade. proponent's of natural gas argue natural gas substitute more dirty sources of electricity generation in the Nordic market, while opponents argue there is no such guarantee and choose to focus on domestic emissions.

Despite several efforts, energy models have failed in resolving this controversy satisfactory. A survey of previous studies using present energy models (EMPS and NORD-MOD-T) for decision support is presented. The models have been re-run and their sensitivity towards specification assumptions examined.

Second part presents a system dynamics model particularly designed to address the short- and long run impacts of energy policies. Results show that gas power will substitute some coal in the short term (as argued by the gas proponent's), but that the substitution effect is modest. When including long-term substitution effects of new investments, gas power also substitute future investments in renewables which results in a *net increase* in CO_2-emissions in the long run. These findings raise serious questions about the environmental benefit of the fuel substitution strategy.

1 Introduction

A remarkable debate has dominated the Norwegian energy policy discourse over the last decade:

> *Will new gas power reduce or increase* CO_2*-emissions in the Nordic electricity market?*

proponent's of gas power argue that natural gas will replace costly and inefficient coal plants in the Nordic market, while their opponent's claim there is no such guarantee and that in fact, the introduction of new renewables will suffer from investments in gas. The controversy already caused the resign of one Government, and continues to hamper constructive dialogues among politicians, NGO's and industry.

Despite several efforts, energy researchers have failed in convincingly resolving this controversy. Though most scientific reports support the conclusion that gas power reduces CO_2-emissions, opinions among researchers diverge. There are two plausible explanations for this:

1. The research question is highly sensitive to the assumptions made
2. The models used do not include all the cause-effect relationships considered to be of importance; therefore their conclusions are not sufficiently persuasive.

In the following, we will examine this controversy in details. Section 3 and 4 of this paper provides a background for the gas power controversy in Norway. In section 5, a simple supply curve analysis is provided. Section 6, 7 and 8 deals with the three electricity market models *EMPS*, *NordMod-T* and *Kraftsim.* The two first are presently used for decision support among utilities and regulators, whereas the latter (Kraftsim) is a new system dynamics model developed for the Nordic electricity market (Botterud et al 2002; Vogstad et al. 2002, 2003 and Vogstad, 2004). Previous simulations are examined and re-run with different specification assumptions. The results support both 1) and 2) for all the three models, but to various degrees.

The paper ends with a discussion on the different modelling concepts, their strengths and weaknesses, and to which extent the CO_2 controversy can be addressed by the various modelling approaches.

2 The Nordic electricity market

The Nord Pool area is a hydro-thermal system with a yearly average generation of 390 TWh/yr, where 200 TWh comes from hydro, 100, 60 and 10 TWh from nuclear, coal and natural gas, and 15 and 6 TWh stems from bio and wind respectively. Renewables play prominent roles in all the Nordic countries' stated energy plans. The abundance of these resources played an important role in industrialising the Nordic countries.

In Denmark, wind energy revived during the energy crisis in the 70ies, and is now the 3rd largest export industry.

Hydropower in Norway gave rise to its energy intensive industry. The paper and pulp industry in Finland and Sweden makes extensive use of bio resources, residuals and options for electricity generation. Nuclear power came into use in Sweden and Finland, but was prevented in Denmark and Norway.

Denmark relies heavily on fossil fuels, but their previous Energy 21 plan (effective before deregulation) aims at phasing out fossil fuels in order to convert to a renewable based energy supply within 2050 (Energy 21). Sweden formulated similar targets for a long-term sustainable energy supply (NUTEK, 1997).

The present situation of the Nordic power supply is summarised in *Table 1*. Scenarios for 2010 are based on several reports (in addition to the above mentioned) according to energy policy goals of each Nordic country.

Table 1 Generation mix in the Nordic countries 1999. The column for 2010 is the future electricity mix according to political targets.

	NOR		SWE		DEN		FIN		Total	
Supply	1999	2010	1999	2010	1999	2010	1999	2010	*1999*	*2010*
Hydro [TWh/yr]	115		63				14.5		*192.5*	
Wind P [TWh/yr]	-	3	-	4	3.5	8	-	1	*3.5*	*16*
Nuclear [MW]			9450	8850			2610	3810	*12060*	*12660*
CHP central [MW]			1280	570	4800	5220	2500	2750	*8580*	*8540*
CHP district [MW]			980	1916	2100	1590	730	2100	*3810*	*5606*
CHP ind [MW]			840	820			1550	1750	*2390*	*2570*
Condense [MW]	0	400	435	-	2400	0	3760		*6595*	*400*
Gas turb.[MW]			195		70		1450		*1715*	
Demand [TWh/yr]	120	123	143	152	34	37	73	85	*370*	*397*

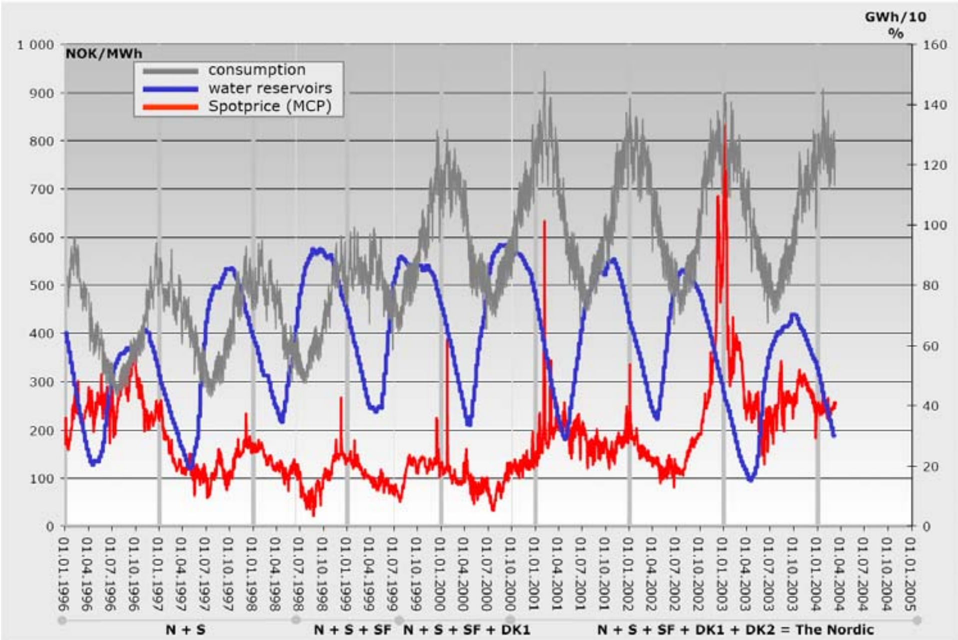
In 1991, the Norwegian electricity sector was restructured into an open market. In 1996, Norway and Sweden formed the first multinational electricity exchange, and the last member (Jutland, Denmark) joined in 2000. The *power balance market, spot market, future-* and *forward market* and *green certificate market* at Nord Pool provide price signals for utilities and consumers for both short-term and long-term planning. The demand side participate in all markets, and so far, the market has turned out to be a liquid, well working competitive market. *Figure 2* shows the historical development of electricity demand, prices and reservoir levels since 1996. Yearly variation of hydro inflow (up to 30%) may cause large price variations from year to year.

3 The Norwegian CO_2 controversy

Natural gas for electricity generation is usually considered to be environmentally beneficial in most other countries, where more dirty sources of generation is substituted. We will refer to this energy policy as *fuel substitution* or *carbon substitution*. In the Norwegian case, the environmental impact of adding gas power is more ambiguous. If we look at the national level, domestic emissions increase, as the Norwegian supply comprise 100% hydropower. But since Norway is a part of the Nordic electricity market, we must consider, at least, the impact of the Nordic electricity supply. In a liberalised market, investment in new capacity will indirectly lead to some substitution of units in the short run, through changes in the spot price that impact the operation of the marginal units. proponent's of gas argue that the marginal units in the Nordic market are the old and expensive coal fired power plants located in Denmark and elsewhere.

Since Norway struck oil in the 70ies, oil and later on gas has been the main export for Norway. It has also been a goal to develop more land-based industry as a spin-off from the

Figure 2 Historical development of consumption, reservoir level and spot price for the Nord Pool market 1996-2004. (Source: Nord Pool)



offshore industry, especially domestic utilisation of natural gas.
In the Norwegian white paper (NOU, 1995), it is a goal to increase the domestic use of natural gas. On this background, several companies looked into the possibility of developing gas power plants in Norway.

Naturkraft owned by Statoil, Statkraft and Hydro was given the first construction permit by Ministry of Petroleum and Energy (OED) in June, 1997. Prior to this decision was an intense debate, and the application process for the emission permit was delayed until after the Parliament election the same year. The emission permit was granted by The Norwegian Pollution Control Authority (SFT) in 1999, which was litigated by NGO's until the final permit was given by Ministry of Environment (MD) in 2001.

March 9th, 2000 the Bondevik Government resigned after losing 81-79 in a Parliament vote of confidence over denying permit for Norway's first gas power plant, being the first Government resigning from disagreements on the Kyoto protocol and the issue of CO_2-emissions[1].

To this date, the permits given for natural gas plants have still not been utilised. Firstly, strict environmental requirements were imposed by SFT after the permits were given, which has been delaying the process. Secondly, the electricity market has not made natural gas profitable yet. Thirdly, infrastructure investments are needed for some of the projects, and fourth; liberalisation of the European gas market does not give Norwegian

1. CNN news, 09.03.2000

developers significant advantages over European developers for gas power plants.

We will now look into the arguments made on this controversy that has dominated the Norwegian environmental discourse for over a decade. Energy models have played a crucial role, in trying to resolve this issue. Despite several efforts, energy researchers have failed in convincingly resolving this controversy, and we hypothesize the reason being that 1) the research question is highly sensitive to the assumptions made and 2) the models do not include all the cause-effect relationships believed to be of importance.

3.1 Gas power proponent's point of view

The basic argument first put forth by *Naturkraft*, was that within the Nordic market, building gas power would substitute coal in other Nordic countries by the operations of the market. Thus, gas power will in the end reduce Nordic CO_2-emissions from a regional perspective. In the processing of the applications, NVE reached the same conclusion. Their conclusions were based on model simulations using the EMPS model and probably NORDMOD-T. In the next round of complaints, OED reaffirmed the conclusions, but admitted there were some uncertainties related to the results.
In the application from Industrikraft Midt-Norge (IMN) of a gas power plant in Skogn, SINTEF Energy Research analysed the impact on CO_2-emissions. The SINTEF study concluded that CO_2-emissions in the Northern European countries (Nordic countries + Germany) will be reduced as a consequence of building gas power. Their analysis was based on the EMPS electricity market model.

In October 2000, the new Stoltenberg Government presented their evaluation of the CO_2 controversy, changing focus from Nordic countries a European level. The Government concluded that CO_2-emission reductions were the most likely outcome from building gas power plants, while this view was contested by the opposition. In addition, the authors that had provided analyses, criticised the Government for misinterpreting their material[1]

3.2 Opponent's point of view

While proponent's argue gas power will substitute coal, opponents argue there is no such guarantee, and that gas power will come in addition to coal power. Opponents also seem to focus on national emissions and international obligations. They argue that gas power will increase demand, and that coal power plants elsewhere is not likely to shut down their plants as a result of the introduction of gas in Norway. They emphasize statements from SFT[2], where it is said that gas power also will delay the necessary transition to renewables such as bio and wind power.
During the new Governments presentation of the issue in October 2000, an IEA report showed that development of new gas plants will continue to grow in EU, without replacing existing coal plants. The EU minister of Environment, Domingo Jimenez-Beltran, rejected the Norwegian Minister of Environment's statement[3] that claimed Norwegian gas power substitute European coal power. No models were involved in the NGO's anal-

1. Interview with T. Bye (Statistics Norway) in Dagbladet, 31.10.2000
2. National Pollution Authority

yses.

From the above discussion, it appears that the proponent’s focus on short-term effects, such as short term substitution coordinated by the operations of the market. Comparative static economics and detailed production scheduling models such as the EMPS model provide tools for analysing these interrelationships. The opponents however, seem to focus on the longer term aspects, and tend to ignore the short-term effects. They consider replacements of investments when speaking of new developments, and even in the longer term about technology progress. There were no model studies however, that incorporated these effects.
None of the groups seem to consider both the short term and the long term aspects (i.e. both substitution effects of generation scheduling, substitutions in investments decisions and so forth). Furthermore, geographical system boundaries are inconsistent in the discussions and in between the model studies. Opponents focus on national emissions, while proponent’s usually consider the Nordic countries plus power exchange with Germany.

4 A simple analysis of supply curve and market prices

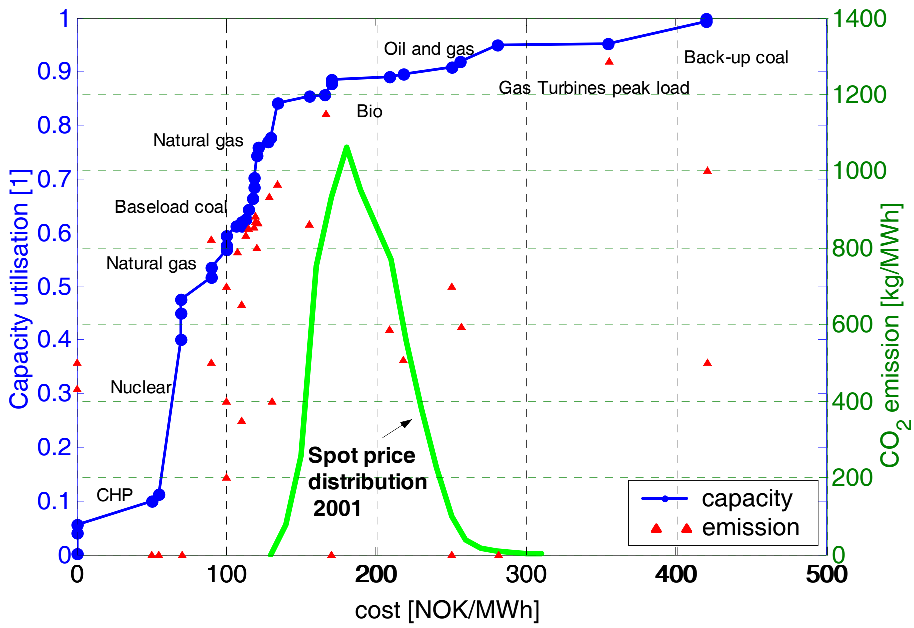
In the Nordic market, electricity generation is scheduled in the short term by short run marginal costs. This information is not readily available in a competitive market, so any information on costs is guesstimates afflicted with uncertainties. *Figure 3* shows the supply curve of the Nordic electricity market that has been used in our EMPS simulation runs and earlier versions of the Kraftsim model (Vogstad et al., 2002). Hydropower, wind power and exchange are not included in the supply curve. Nord Pool’s spot price distribution for 2001 is shown in the same graph. Held together with the supply curve, the data shows a picture that does not quite match the assumptions of coal being the only generation technology replaced by gas. From the supply curve, coal serves as baseload well below the average spot price level. Among baseload units are also CHP (including bio), nuclear and natural gas units operating at marginal costs below spot prices. In the range of the spot price distribution, we find some coal, oil, bio and gas. Peak load gas turbines and backup-coal can be found well above the price distribution range, suggesting that the inefficient and costly coal fired units are not frequently in use. The picture is thus more complex than assuming coal to be marginal generation. Rather, inspection of the graph and the production data (see Appendix 1) indicates that new gas power replaces existing gas power (as well as coal and oil) in the Nordic market.

This supply curve analysis does however not provide the complete picture. Firstly, exchange is not accounted for, and capacity constraints for transmission between countries are not included. Furthermore, hydropower with reservoirs is not adequately represented in a supply curve as the water values change with changes in reservoir level content. On a yearly basis however, hydro schedulers try to schedule generation in order to maximise profits while avoiding spillage. To include such considerations, electricity market models have been developed that simulate the behaviour of the market. These models have also been used to address the CO_2 controversy. In the following we will examine simulations analyses by the EMPS model and NORDMOD-T. The new system dynamic model Kraftsim, is meant as a complement to existing decision support tools, both

3. Interview with Domingo Jimenez-Beltran, (EU Minister of Environment) in Dagbladet 25.10.2000

Figure 3 Supply curve, emission intensity and spot price distribution in the Nordic electricity market. The spot price distribution was calculated from hourly time series for the Nord Pool market in 2001.

a)



for utilities and regulators. *Table 4* summarise the three model characteristics and their differences. In the subsequent sections 6 to 8, we will examine the simulation runs that address the CO_2 emission controversy.

Table 4 Overview of model characteristics

Model	EMPS	NordMod-T	Kraftsim
Purpose	Optimal hydro scheduling and price prognosis	Policy analysis, maximises socio-economic surplus	Policy analysis
Type	Technical bottom-up, partial equilibrium. Stochastic dynamic optimisation of hydropower generation	Technical bottom-up, partial equilibrium. Optimisation of socio-economic surplus	System dynamic with focus on competition between energy technologies
Time horizon	1 year	<20 yr	<30 yr
Spatial resolution	12 areas (Nordic countries+Germany)	4 areas (Nordic countries)	One area (Nord Pool)
Electricity price	**Endogenous**	**Endogenous**	**Endogenous**
Demand[1]	**Endogenous**	**Endogenous**	**Endogenous**
Generation scheduling	**Endogenous**	**Endogenous**	**Endogenous**
Capacity acquisition	**Exogenous**	**Endogenous**	**Endogenous**
Resource availability	**Exogenous**	**Endogenous for hydropower**	**Endogenous for renewables**
Technology progress	**Exogenous**	**Exogenous**	**Endogenous for renewables**

1. Demand growth rate is exogenous, while price elasticity of demand is endogenous

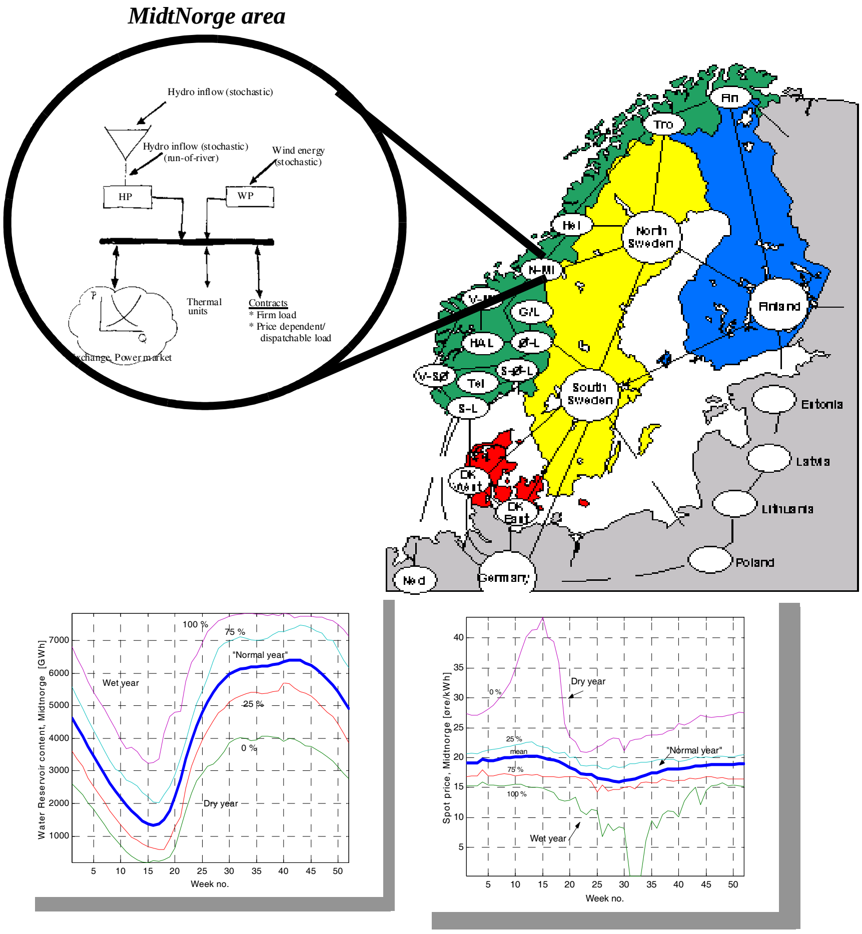
5 Analysing CO_2-emissions with the EMPS model

EMPS (Efi's Multi-area Power Simulator) is a decision support tool for seasonal hydro scheduling. Though it was originally developed for hydro scheduling purposes and price prognosis (Fosso et al. 1999), it is also used for energy policy studies

The model is a technical bottom-up model containing a detailed representation of the hydraulic system of reservoirs and generating units. The supply side is described with individual plants within each area. The stochastic representation of hydro inflow utilise 60-70 years of historical inflow data. The model optimises hydro generation over a year using stochastic dynamic programming and the water value method. Main features and exogenous versus endogenous variables are displayed in *Table 4*. Electricity price and generation scheduling is endogenous, while long term mechanisms such as capacity acquisition, technology progress and resource availability does not need to be represented within the one-year time horizon. *Figure 5* shows an overview of the physical description of supply and demand within each area. The graphs show the optimal reservoir level curves, and the resulting prices. The results are shown as percentiles emphasizing the stochastic optimisation of hydro scheduling with stochastic inflow.

The EMPS model has been used to analyse the impact on Nordic CO_2-emissions from building new gas power plants (Wangensteen et al., 1999) Sintef Energy research provided the impact study of changes in Northern-European CO_2-emissions from build-

Figure 5 The EMPS model consists of several interconnected local areas with various supply technologies, demand and market access. (Source: Vogstad et al, 2001; Vogstad 2000)

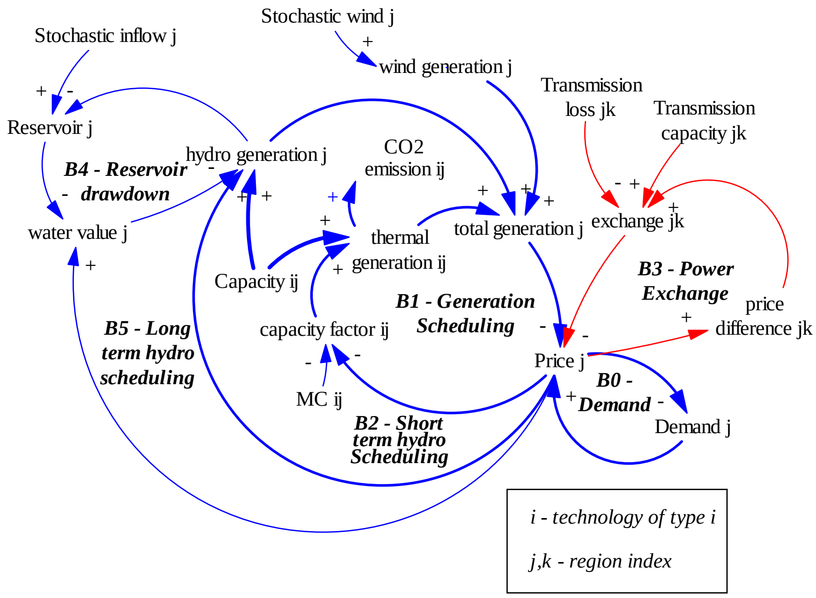


ing 800 MW gas power in Skogn papermill, located 100 km's north of Trondheim.

The results are reported in Wangensteen et. al (2000) and in the consequence report[1]. *Figure 6* shows a CLD representation of the EMPS model. As can be seen, Capacity is exogenous to the model. Consequently, investment substitutions must be handled exogenously. The power exchange loop (B3) represent exchange between areas. The exchange depends on the available transmission capacity between the areas, and the price difference. The market clears generation and demand for each time step[2]. Thermal generation is based on marginal costs (MC_{iv}), whereas hydropower and wind power differ in this respect. Wind generation is stochastic (represented by 30 years of historical data), and hydro inflow utilise 60 years of historical data in its stochastic representation. Hydro generation is based on the water value principle, in which a value of storing one additional unit of water is derived from a stochastic dynamic optimisation of the expected future

1. Available online www.industrikraft.no
2. Time resolution is one week, but demand can be subdivided into load blocks (usually 4) for within each week.

Figure 6 CLD representation of the EMPS model



profits over the time horizon (Vogstad, 2004). The interdependency of hydro generation, reservoirs and spot price is illustrated by the *Long term scheduling* and the *Reservoir drawdown* loop.

Table 7 shows the concluding result from the Skogn analysis by SINTEF Energy Research using the EMPS model It was concluded that adding 800 MW gas power in Skogn would increase domestic CO_2 - emissions by 1.9 Mt/yr, while emission reductions take place in other Nordic countries and in particular Germany. The result is a net reduction of 1.1 Mt CO_2 per year. As can be seen from the tabulated values, differences are small in comparison to the total emission values, which suggest the analysis to be highly sensitive to assumptions made.

Table 7 Results from the Skogn study using EMPS (Source: Sintef Energy Research, 2000)

All numbers in Mt CO_2/yr	Without gas power plant	With gas power plant	Difference
Norway	2.1	4.0	+1.9
Denmark	23.3	22.9	-0.4
Sweden	8.8	7.9	-0.9
Finland	40.8	40.5	-0.3
Germany	366.3	364.9	-1.4
SUM Nordic+Germany	441.3	440.2	-1.1

Table 8 EEPS simulations re-run with various data sets and assumptions change in CO_2 - emissions

Scenario	Nor	Den	Swe	Fin	Ger	Tot
Skogn2005	1.8	-0.3	-0.9	-0.3	-1.4	-1.1
1999	2.3	-1.1	-0.6	-1.0	-1.8	-2.2
ref2010	3.2	-0.1	0	-1.3	-2.9	-1.1
wind2010	2.4	-0.3	-0.1	-1.3	-2.4	-1.7
noexchange2010	2.2	-0.6	-0.4	-2.0	0	-0.8
newdata2010	2.3	-0.7	-1.3	-1.2	-1.3	-2.0
noboilers2010	2.5	-0.7	0	-1.1	-1.3	-0.6

In *Table 8*, new simulation runs have been performed to assess the robustness of the results compared to the Skogn study. The scenarios are as follows:

Skogn 2005 - This scenario is taken from the Skogn study (Sintef report), where there is a weak growth in demand (1.2%/yr) towards 2005 and some new transmission capacity (600 MW) to Germany is added.
ref1999 - Nordic situation as of 1999, with the data set in shown in *Figure 3* corresponding to the installed capacity in 1999. The resulting CO_2-emissions from this scenario correspond well with actual CO_2-emissions for that year (Vogstad, 2000). (See Appendix 1)
ref2010 - Scenario 2010 without new wind power, as defined in *Table 1*
wind2010 - With 16 TWh/yr wind power according to each country's plans. (see *Table 1*)
noexchange2010- Scenario as for wind 2010, but without exchange to Germany.
newdata2010 - Scenario with new data set for Germany based on Bower et al (2000)
noboilers2010 - Same as newdata2010, but substitution reduction on demand side (i.e. electrical boilers) omitted.
The scenarios ref1999 and wind2010 scenarios are also documented in Vogstad et al. (2000).

We will shortly comment upon the above tabulated results. The results clearly show the short-run substitution effect for all of the scenarios. The major share of substitution takes place in Germany, followed by Finland. Some of the results will be commented upon in the following. A large substitution effect is seen in 1999 compared to the scenarios for 2010. Especially in Denmark, fuel switching from coal to gas is scheduled, as new coal power is prohibited, which results in lower substitution effects of CO_2 in the 2010 scenarios. A larger share of the substitution is then moved to Germany. The difference between ref2010 and wind2010, is the addition of wind from 4.5 to 16 TWh according to the Nordic countries wind energy goals in 2010. The increase in substitution effect between these scenarios is due to substitution on the demand side. In the noexchange2010 scenario, we only removed the possibility for exchange to Germany, which results in increased substitution within the Nordic countries. The result shows a significant reduction in Finland, due to some of the Finnish coal plants. In newdata2010, a new data set for Germany is used, based on Bower et. al (2000). The results yielded more CO_2 - reductions in Sweden due to more imports from Germany. The last scenario, noboiler2010 shows the same results when the substitution effects from oil/el boilers and other demand side flexible loads are not accounted for. This sensitivity analysis shows that the main substitution effect is actually on the demand side, where cheaper electricity prices result in fuel switching from oil to el in flexible boilers. The uncertainty of the installed oil/el boilers and their operations (depending on changes in oil taxes etc.) is considered to be substantial.

However, all the scenarios show reductions of CO_2 from building gas power in Norway. Most substitution takes place in Germany, thereafter Finland, while the substitution effect in Denmark and Sweden is less significant.

Two data sets for Germany were tested, and the latter is believed to be more updated. Based on demand and supply provided by the data set, however, electricity prices in Germany should be around 90-130 NOK/MWh, as calculated by the EMPS model. The observed prices in the European Energy Exchange[1] (EEX), are however much higher (170 NOK/MWh in 2000, and 240 NOK/MWh in 2003) without any significant changes in the supply or demand. An explanation for these high prices is provided in Bower et. al (2000) as strategic bidding enabled by increasing market concentration. Observed market prices and data on supply/demand and marginal costs of generation does therefore not match, which poses a dilemma for *all* of the three models if we are to assess the environmental impact of import/export to Germany.

The benefit of using the EMPS model, is the good description of hydro scheduling and price formation in the Nordic market. The disadvantage is that the long-term effects such as investment substitutions of capacity acquisition is not included in the model and must be assumed for each scenario.

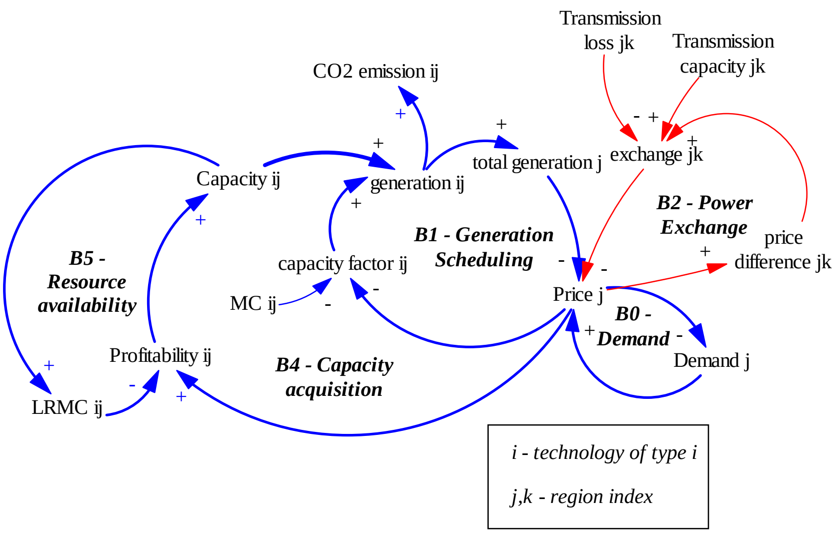
6 CO_2-emission analysis using NORDMOD-T

Both generation scheduling and investment decisions are endogenous in NORDMOD-T, and analyses using this model should therefore also include effects of investment substitution. *Figure 9* shows the *generation scheduling, power exchange, capacity acquisition* and *resource availability* feedback loops. Investments in a technology are made if long-run marginal costs are lower than the market price for the *next time period.* Capacity is then added the next period (investments are made at the start of each year). There is also a maximum constraint on the amount of capacity from each technology that can be added.

The model is also a detailed bottom-up description of technologies, using load duration curves and blocks that characterise four load modes for four seasons. Aune et al. (2000) summarise their findings in their studies. Some aggregated results are shown be-

1. For price information at European Energy Exchange see www.EEX.de

Figure 9 CLD representation of NordMod-T



low:

The study analysed high, low and medium price scenarios for Europe, while coal was assumed to be the marginal unit of generation in Europe.
However, if prices are high, gas power is more likely to be the marginal unit in Europe. It turned out that investments in wind power was exogenously determined, so eventual substitution effects of renewables only consider biomass.
Assumptions of transmission capacity and non-Nordic electricity prices are shown in

Figure 10 Left: Assumptions on tranmission capacity to non-nordic countries. Right: Price scenarious for non-Nordic countries, base run. (Source : Aune et al. 2000)

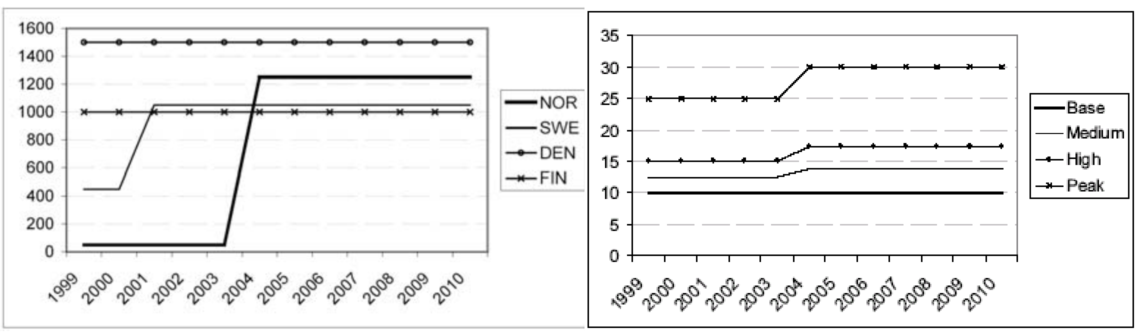
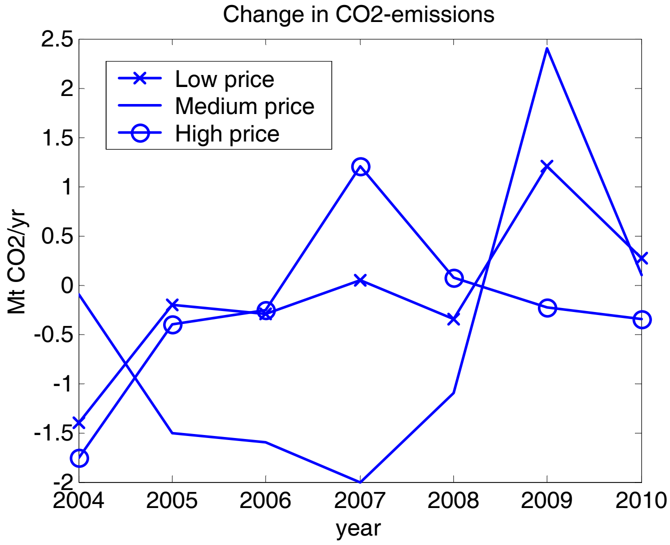


Figure 10 for the NordMod-T simulations. *Figure 11* shows the development of CO_2 -emission from adding 5.6 TWh Norwegian gas power in 2004 for various assumptions of non-Nordic electricity price; Low, medium and High prices. Low prices are 80, 110 and 140 NOK/MWh for base, medium and high block; Medium price scenario is 100 NOK/MWh for baseload, and correspondingly +25% and +50% higher prices for medium and high block. The high prices scenario assume 150, 188 and 225 NOK/MWh for base

block, medium and high block prices.

Figure 11 Changes in CO_2 - emissions from adding 5.6 TWh gas power in Norway in 2004. (emission changes in non-nordic countries included). The three scenarios include Low, Medium and High non-nordic electricity prices. (Adapted from Aune et al., 2000)



The study concluded that there is high uncertainty whether building gas power in Norway increase or reduce Northern European CO_2-emissions, and that the results rely heavily on the assumptions made, in particular the price level in Europe, and the available transmission capacity to Europe. If transmission lines were congested so that Norwegian gas power would substitute generation in other Nordic countries, gas would substitute gas and hence there could even be increased CO_2 emissions.

7 CO_2-emission analysis using Kraftsim

The Kraftsim model was developed to analyse long-term versus short-term consequences of energy policies within the context of a liberalised Nordic electricity market (Vogstad, 2003; 2004). The time horizon is 30 years, and the time resolution sufficiently captures features of generation scheduling at a seasonal and weekly level[1]. The Nordic market is represented as one area, and the model has no spatial disaggregation. The model focuses

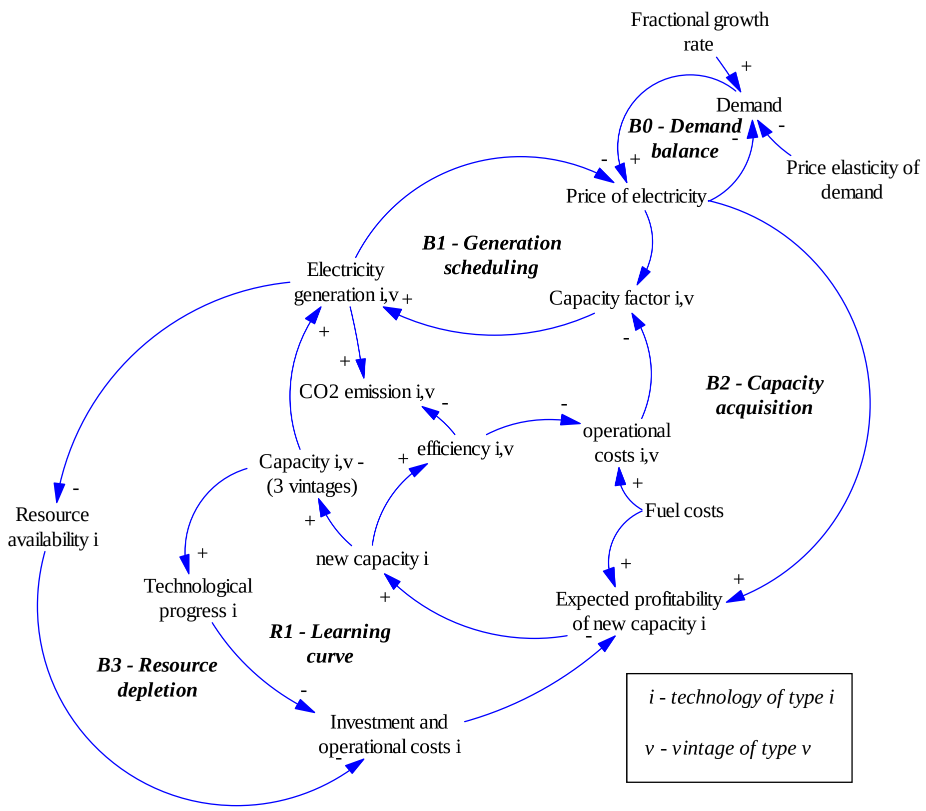
1. The smallest time constant is 3 days for spot price adjustments, in order to clear supply and demand with a weekly load variation. The numerical time step is 1 day. To capture daily load pattern, spot price adjustment time and the numerical time step can be adjusted down to an hourly resolution. This will be done when the effect of start/stop costs and ramp-up constraints are included for each generation technology (i.e. the *unit commitment* problem)

on the competition between the following main technologies *i*:

nu - nuclear
co - coal
ga - natural gas
gc - natural gas with CO_2 sequestration
gp - natural gas peak load;
hy - hydro
bi - bio
wi - wind onshore
wo -wind offshore.

The main loops of Kraftsim is shown in *Figure 12*

Figure 12 Kraftsim CLD diagram



B1 - Generation scheduling. On a daily basis, electricity generation is scheduled by marginal costs of operation. The last unit in operation determine the spot price at each time point (in a uniform-price auction, perfect market). In this model, the supply is described by each of the nine technologies *i*, their vintage *v* and fuel costs.
B2 - Capacity acquisition is the process of investing in new capacity based on the expected profitability of new capacity. Expectations of future electricity prices play a crucial role in this case. If the expected future electricity price sustains at levels higher than the

long run marginal cost of new generation, new capacity is added.
R1 - The learning curve effect is a reinforcing loop. As more capacity is developed, the technology and know-how progresses, reduces the costs and increase the profitability of new capacity.
B3 - Resource depletion finally constrain expansion of new capacity. All resources are constrained in terms of available land, riverfalls or fossil reserves. As more resources are utilised, costs of utilising the remaining resources increase.
All decisions governing the operations and investments in technologies occur in a competitive market. Short term prices govern generation scheduling (B1), investment decisions are based on profitability assessments (B2) and resources and technology progress (R1) is partly endogenous to the model (compare with *Table 4).*

This paper reports of a specific policy study using the Kraftsim model and we will only briefly present the most important assumptions underlying the model. A complete documentation of the Kraftsim model can be found in Vogstad (2004)[1].
All the decisions are made in a competitive environment.

7.1 Generation scheduling

Other electricity markets such as the German, Dutch, Spanish, UK, and Californian market are characterised by some few, dominating market players. In contrast, the number of market participants in the Nord Pool market is fairly large, and regarded as highly competitive[2]. It is therefore assumed that market participants bid into the spot market according to their marginal costs (i.e. a perfect spot market). This assumption is in accordance with the two previously mentioned models.

Generation scheduling

(1) $CF_{iv} = f_{iv}(Price/operational\ cost_{iv})$ *[1]*

(2) $operational\ cost_{iv} = Fuel\ cost_i / resource\ efficiency_{iv}$ *[NOK/MWh]*

where $f_{iv}(.)$ is a table look up function that has the shape of a cumulative density function. The sum of all technologies i for all vintages v then represent the aggregated supply curve for thermal technologies. The marginal costs of hydropower are calculated by the water value, while wind generation is determined by the wind conditions.

7.2 Investment decisions

Investments are purely based on a Return on Investment criteria (ROI) for profitability considerations using net present value calculations. The required return on investment uses an interest rate of 7%, which is the recommended interest rate for socio-economic calculations. In a competitive environment, utilities require higher interest rates and

1. Available at www.stud.ntnu.no/~klausv under publications (*forthcoming*)
2. Hansen et al. (2001) argue that historical observations of the Nord Pool market may be misleading in the evaluation of market power. Nord pool inherited a power system with excess capacity from the regulatory regime. There is a trend in mergers and acquisitions. With increasing market concentration, market power may become a problem in the near future

shorter pay back periods in their profitability assessment. The resulting investments are therefore considered to be in the optimistic range.

Price expectations play a crucial role in the profitability assessment of a generation technology. The futures market at Nord Pool represents the best available information on the joint expectation of future electricity prices up to 4 years ahead. Yet, investors need to consider longer time horizons than just 4 years ahead and need to take other information into account. Investors can then look at the long-term fundamentals of the supply and demand. A convenient rule is to assume that the electricity market will converge towards long-term equilibrium at which the long run marginal costs of the least expensive technology sets the market price[1]. But this type of information is also uncertain, as it for instance relies on fuel price expectations.

On the other hand, future markets are influenced by conditions of the present, such as two consecutive dry years resulting in low reservoir levels, cold winters, or similar occurrences that will even out in the long run. We therefore assume the investor to pay some attention to the futures market, and some attention to the long-run marginal costs of new generation as described in Eq (3) and (4) below:

Profitability assessment

(3) Expected future price = Weight on LRMC $\cdot min_i\{LRMC_i\}$ *+ (1-Weight on LRMC)·Futures price [NOK/MWh]*

(4) Weight on LRMC = 0.6 [1]

The *effect of profitability on investment rate multiplier* governs applications and investment decisions, based on the $\frac{ROI}{RROI}$ (return on investments to required return on invest-

1. Statements by executives and interviews in media suggest that investors use this rule when looking beyond the futures market.

ments ratio):

(5) *effect of profitability on investment rate*$_i$ = $f_i(ROI_i/RROI_i)$ [1]

(6) $RROI_i$ = $Lifetime_i \cdot annuity\ factor_i$ [1]

(7) *annuity factor*$_i$ = *Internal rate of return/(1-(1+Internal rate of return)*$^{-Lifetime_i}$*)* [1]

(8) *Internal rate of return = 7* [%/yr]

(9) ROI_i = *(Expected future price - operational costs*$_i$ + $O\&M_i$ - *Incentives*$_i$*)/Energy investment costs*$_i$ [1]

(10) *Energy investment costs*$_i$ = *Investment costs*$_i$ / *(Expected CF*$_i$·*Full load hrs*$_i$ ·*Lifetime*$_i$ *)* [NOK/MWh]

(11) *Investment costs*$_i$ = *Initial investment costs*$_i$ · *learning multiplier*$_i$ [NOK/kW]

(12) *operational costs*$_i$ = *Fuel cost*$_i$ / *Resource efficiency*$_i$ [NOK/MWh]

(13) *Incentives = {0,0,0,0,0,0,100,100,100}* [NOK/MWh]

(14) *Lifetime*$_i$ = *{40,30,30,30,30,40,30,20,20}* [yr]

(15) *CF estimated*$_i$ =f_i*(Price/operational costs*$_i$*)* [1]

(16) *Yearly average CF*$_i$ = *SLIDINGAVERAGE(CF estimated*$_i$ *, 1 yr)* [1]

(17) *Expected CF*$_i$ = *DELAYINF(CF estimated*$_i$*, 3 yr)* [1]

(18) *Fuel costs*$_i$ = *{26.4, 47,80,80,80,0,80·effect of resource on fuel costs bi,0,0}* [NOK/MWh]

Where *f(.)* denotes a table look up function, and *Full load hrs*$_i$, *Resource efficiency*$_i$ *and learning multiplier*$_i$ is defined elsewhere in the model (see *Figure 14*). *Figure 16* shows the development of LRMC for each technology that is endogenously computed by the model. (The initially high LRMC values for gas with CO_2 sequestration (4) and gas peak load (5), is the very low expected capacity utilisation of these technologies at low electricity prices, see Eq (15)).

7.3 Technology progress

Technology progress is difficult to endogenize in a regional model, since much of the technology progress usually occurs at a global level.

However, Danish wind turbine manufacturers are among the world leaders. The early stages of wind turbine development can largely be attributed to the development in Denmark, and are now taking the lead in developing offshore wind parks in the shallow waters surrounding Denmark. The Nordic countries all have good resources for further wind power development.

Sweden, Finland and Denmark all have a strong foothold in bio energy. A large paper and pulp industry has provided favourable conditions for bio energy to develop in both Finland and Sweden, whereas residuals from the large farming industry has motivated RD&D[1] of bio energy in Denmark.

Norway has strong traditions in hydropower technology. Hydropower is however a mature technology and there is less potential for improvements, but there are still advancement in the development of small scale hydropower. Local adaptations have to be

1. Research, Development and Deployment

done for bio energy concerning resource base, infrastructure and industry.
We could therefore justify learning to be endogenous for the renewable technologies, although learning can also be represented exogenously.

In the case of thermal generation technologies, the learning effect is taken as exogenous as the major environments and markets for thermal generation technologies are outside the Nordic countries.

7.4 Resource availability

Prices on nuclear, coal and natural gas are assumed to be fixed during the simulation period. This assumption is rather conservative with respect to the price of fossil fuels. Most scenarios for fossil fuels indicate rising prices, in particular for natural gas. The assumption of natural gas prices in the Nordic countries being independent on the construction of gas power could also be questioned, so the development of gas power is rather optimistic in our model.
There is a feedback from hydropower, bio and wind resources to the costs of developing new resources. For each project developed, less attractive sites must be utilised. An exemption is offshore wind power, for which we assume there to be neglible feedback to costs during the time period considered in our model.

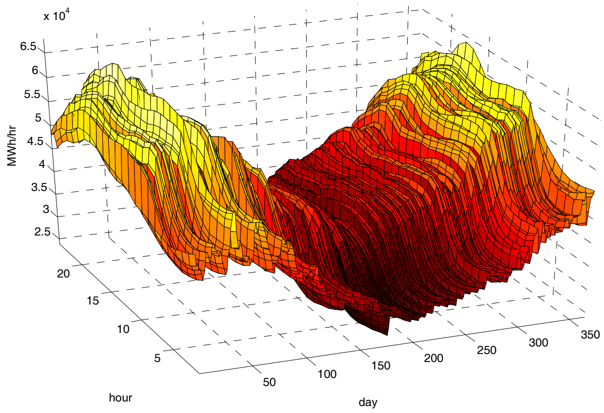
7.5 Demand side

Demand side is kept simple in this model. We account for an underlying growth trend of 1.5%/yr, a weekly and seasonal variation[1]. In addition there is a price elasticity of demand (0.3 1/yr) that reflects improvements in energy efficiency or new investments on the

1. Actually, daily load variation is more important than the weekly variation, while seasonal variation is the most important. The model can increase resolution to capture hourly variation, but will involve more model development on the supply side.

demand side.

Figure 13   Electricity demand profile organised into seasonal and hourly variation (Adapted from Nord Pool, 2001).



7.6 Capacity acquisition and vintage structure

On the basis of profitability assessments, investors submit applications to the authorities. The application processing takes time, depending on the technology. The final investment decision is made later on, after permits have been obtained. The application process takes from one to several years, and construction involve significant time delays as well.

Capacity has been divided into three vintages *v*: *new*, *intermediate* and *old*. Each vintage is characterised by its *resource efficiency*. Old coal plants are typically less efficiency than new ones. The continuous replacement of old plants with new, more modern plants increase efficiency of the capacity stock, and consequently the supply curve of generating units and related CO_2-emissions.

The corresponding stock and flow diagram is shown on next page

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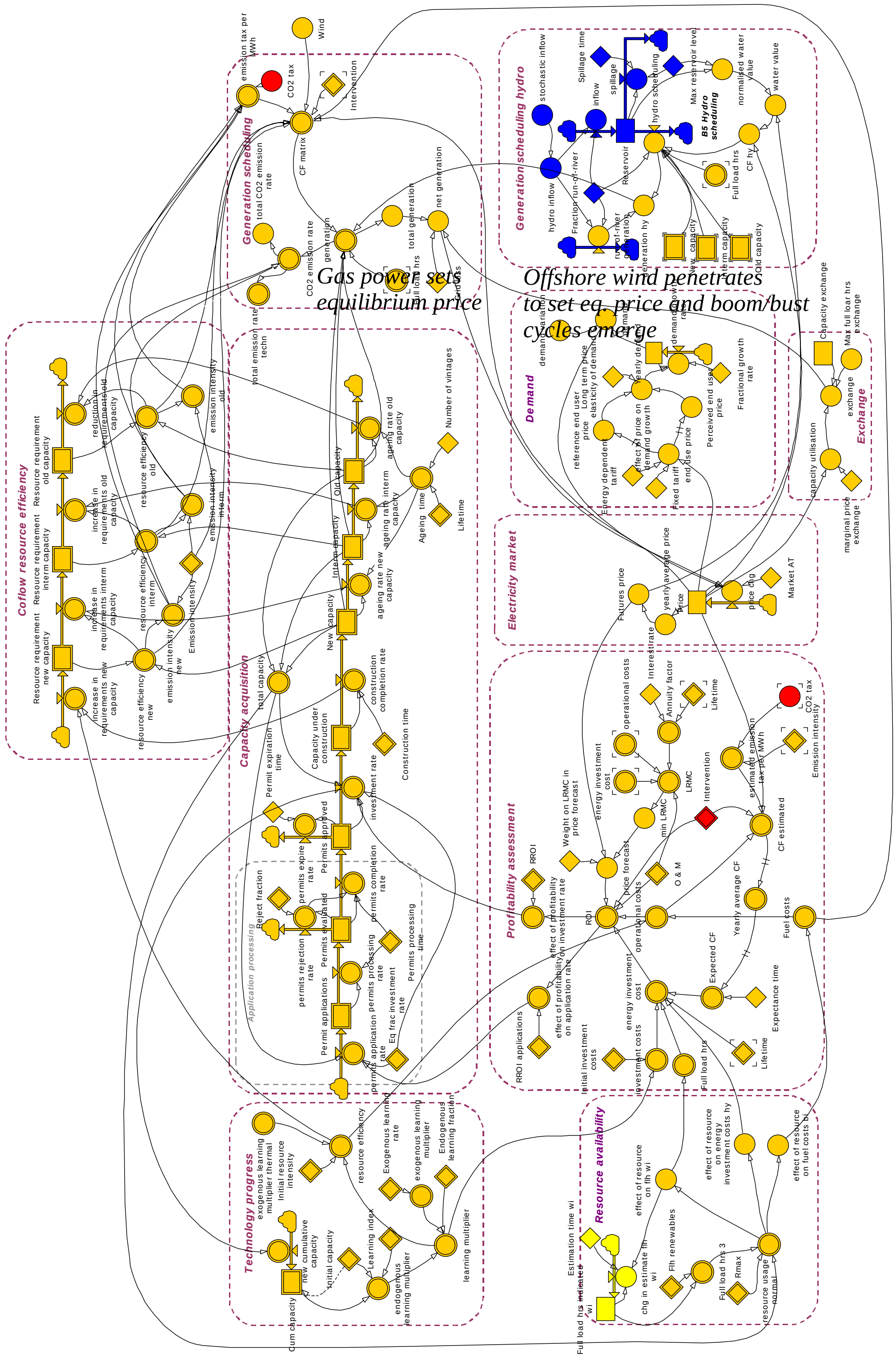
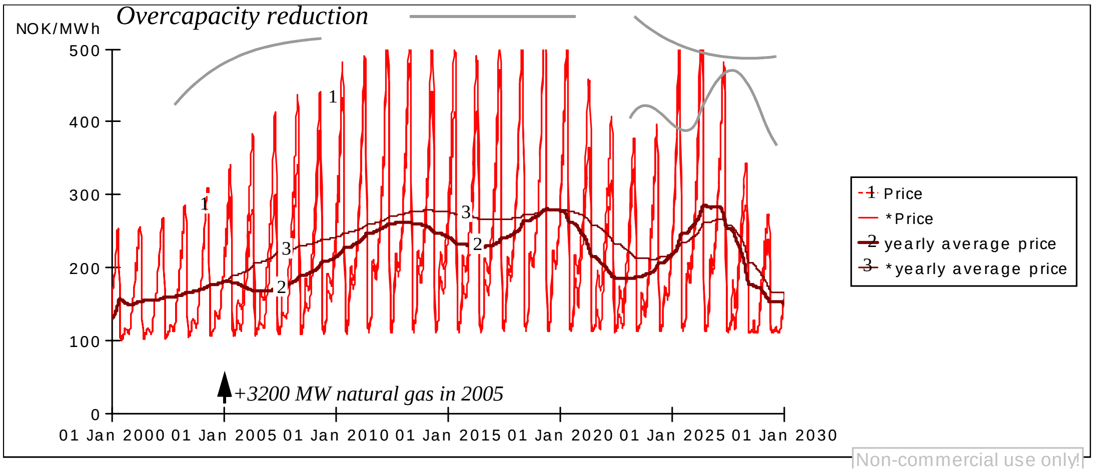
Figure 14 Kraftsim model SFD diagram



7.7 Simulation results

To test the system response of the fuel substitution strategy, we introduce 3200 MW of new natural gas in 2005. This simulation run is compared to a reference run in the following graphs. The reference run displays the evolution of the Nordic electricity market towards 2030 in terms of electricity price development, investments, generation mix and finally CO_2-emissions. In all simulations, a subsidy of 100 NOK/MWh is provided to all renewables technologies except hydropower. The resulting data are smoothed to yearly averages, while the underlying simulations include seasonal variations.

Figure 15 Spot price development for the reference case (*) and the fuel substitution scenario introducing 3200 MW natural gas in 2005.



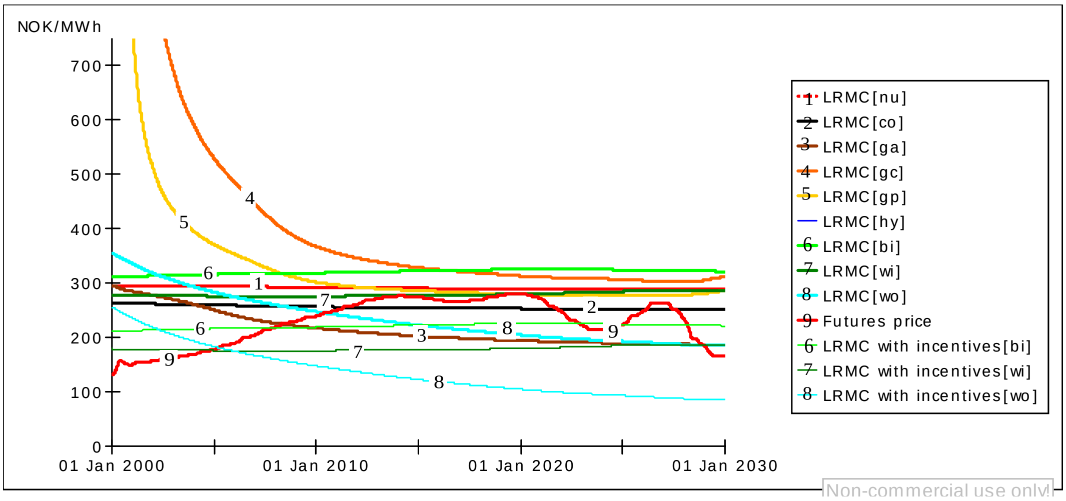
7.7.1 Electricity price development

The observed development in the reference run deserves some explanation. In *Figure 15* the spot price (1) is shown. The rapid fluctuations (1) are caused by the seasonal and weekly variations in demand, which is quite significant in the Nordic market due to a substantial share of electrical heating and the seasonal inflow of hydro. To easier identify price trends, the *yearly average price* (3) is plotted as a sliding yearly average. In the reference scenario, we observe an increasing price towards 2015, whereas prices show a declining trend towards the end of the simulation period. Towards the end of the simulation period, prices exhibit long-term oscillations.

The increasing price trend towards 2015 is due to the initial overcapacity in the Nordic market. The capacity acquisition loop drives the market towards long-run equilibrium, so that the long-run electricity market prices approach the long-run marginal costs of new generation. If we compare the *futures price* with the long-run marginal costs (LRMC) of new generation in *Figure 16*, we see that the futures price will converge towards LRMC for gas power and, in the long run, offshore wind power. The market price converges to LRMC for the cheapest technology on LRMC and *futures prices* (see chapter 7.2) - depending on investors' weight on LRMC and futures prices. For more details on the price development, see Notes a the end of the paper.

The price response to introducing 3200 MW natural gas in 2005 is shown as the bold line (2) in *Figure 15*. Obviously, the introduction of new gas power suppresses electricity

Figure 16   Future prices versus long run marginal costs of generation technologies



prices. Introducing 3200 MW in a system of 80 000 MW also triggers long-term price oscillations, which in turn can cause boom/bust cycles in the acquisition of new capacity. Although an interesting result itself, oscillations are not the focus of this study. (See Notes for extended discussion).

7.7.2 Substitution effects in capacity and generation

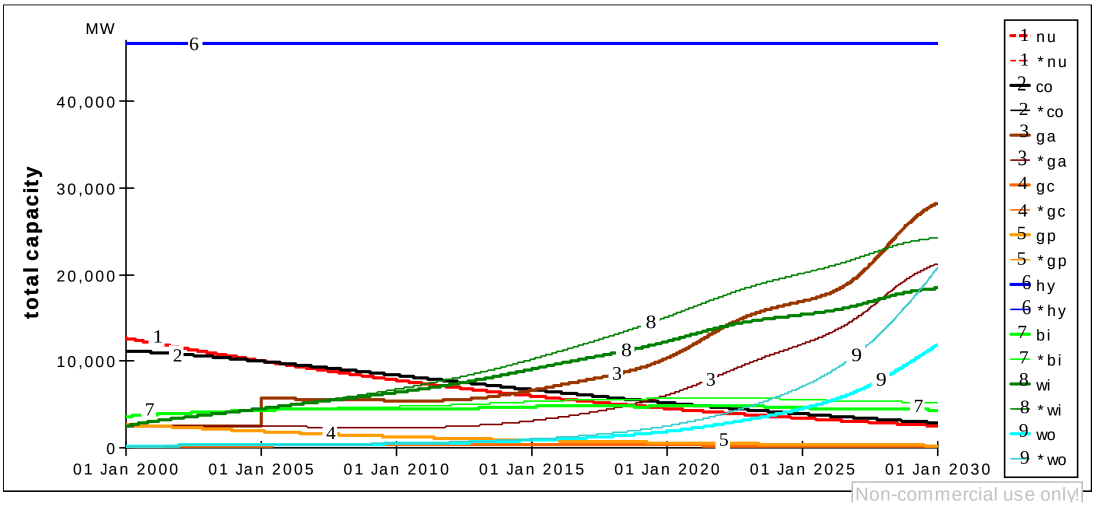
Figure 17 shows the development of capacity for the reference run (thin lines) and the fuel substitution scenario (bold lines). The reference run shows a steady growth in natural gas and wind power. At the end of the time period, offshore wind power becomes significant, while bio energy does not show significant growth. The hydropower resources are already fully utilised, whereas nuclear and coal is phased out due to their low profitability[1]. Peak load capacity is also being phased out, as it is not profitable to invest in peak load capacity purely from electricity price considerations.

The bold lines shows the fuel substitution scenario, where 3200 MW natural gas is added in 2005. The immediate system response in capacity development does not differ significantly from the reference run, but as the simulation progresses, new investments in bio, wind and offshore wind are systematically reduced compared to the reference run. *Thus, investments in gas substitute new investments in renewables in the long run.*

If we now consider generation scheduling, *Figure 18* shows the (averaged) yearly generation for each technology. As can be seen, coal (2) responds slightly by reducing its capacity utilisation when 3200 MW natural gas is added in 2005. The marginal costs of coal are, however well below the new market price trajectory, and the substitution ef-

1. Uncertainties of CO_2-quota prices make coal less attractive as well. In Denmark, new coal plants cannot obtain construction permits. Sweden decided in 1980 to phase out their existing nuclear capacity, but so far only 600 MW of the capacity has been phased out. On the contrary, Finland recently decided to expand one of their nuclear plants. According to NVE, investment cost for the new Finnish plant was reported to be 13 kNOK/kW (NVE 2002 p22), while average investment costs of nuclear plants are 22.5 KNOK/kW in the same report. The increased focus on risk in a competitive environment also make these investment-intensive technologies with long lead time less attractive.

Figure 17 Capacity development. The investment substitution effect of adding gas power



fect from coal is therefore modest. Exports increase, which substitute coal abroad as well. The marginal costs of coal are typically in the range of 100 NOK/MWh before the capacity utilisation of coal is significantly reduced. Hydropower also responds to the added capacity of gas. In hydropower generation, the water values[1] are compared to the spot price. If water values are lower than the current spot price, it is more profitable to release water than store the water for later generation. Water values are however, regularly being updated when new information arrives on inflow, consumption or new capacity. It takes some time before all the utilities involved in hydropower generation incorporate new information into their production planning tools (such as the EMPS model). Reservoir levels can, in addition to seasonal variation of inflow, absorb variations in generation from year to year, but usually not more than three years.

The reduced generation corresponding to reduced investments can be observed for bio, wind and offshore wind (see bold line 7,8 and 9) in *Figure 18*.

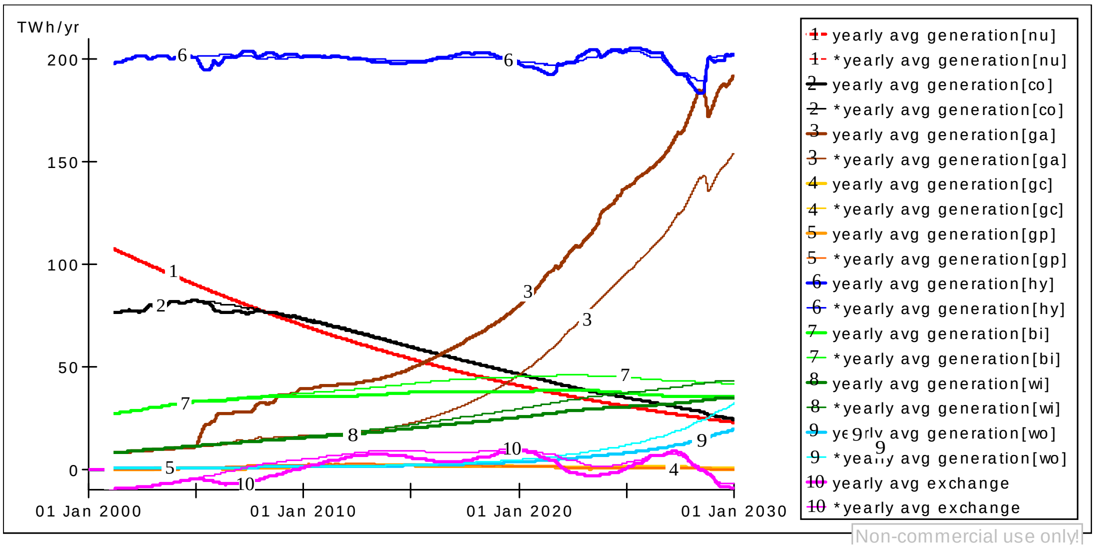
7.7.3 Long run versus short run effect of the fuel substitution strategy on CO_2-emissions

With respect to CO_2-emissions, the consequence of introducing gas power has both short run and long run implications. In the short run, CO_2 emissions from coal and peak load turbines are reduced, but this effect is modest as discussed in the previous section. The increase in exports (negative values) compared to the reference run significantly contributes to reduce CO_2-emissions. This contribution is also accounted for in the total emission rate, and as argued by proponent's of gas power, we can observe a short-term total CO_2-reduction.

Thus, gas power substitute generation some generation from coal in the short run. As a very conservative assumption, we assumed the marginal electricity generation from the continent (Germany, Poland and the Netherlands) to be coal with the least efficient tech-

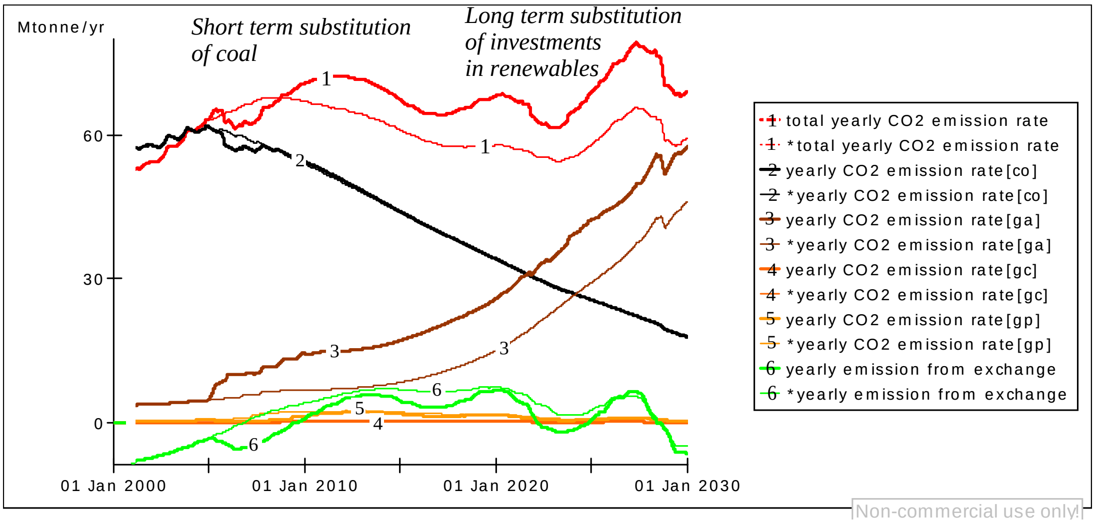
1. Water values reflect the marginal value of storing one additional unit of water

Figure 18 Yearly generation. Short run substitution effects in generation of adding gas power.



nology. This conservative assumption provide an upper bound scenario for emissions accompanied by imports, but even in this case - total CO_2 emissions increase in the long term! The substitution effect of gas towards reducing coal in the Nordic countries and through exchange does not compensate for the long run substitution impacts on investment in renewables and the long term stimulation of demand increase.

Figure 19 Change in CO_2*-emissions from building gas power compared to reference run (*)*



8 Structural- and parameter sensitivity of the simulation results

8.1 Parameter sensitivity

Various scenarios were tested for the EMPS model simulation that gave different levels of CO_2-emission reduction, but each result gave a net CO_2-reduction.

The NordMod-T study contained several scenarios with low, intermediate and high relative prices between EU and Nord Pool. The results showed that 1) the Transmission capacity was important for the result, and 2) that there was no certain impact of CO_2-emission from adding gas power in Norway. The study emphasised the significant uncertainty related to the results.

In the Kraftsim case, some additional simulation runs were performed to assess the robustness of the results. Assumptions were also made conservative, i.e. it was assumed that exchange to the continent would replace old coal fired units. Another extreme sensitivity test was to rule out technology progress as uncertainties of the learning curve effect could yield too optimistic results on development of renewables. However, the results still showed significant increases in CO_2-emissions when adding gas power.

8.2 Representing transmission constraints

One of the main differences between the three models, are the spatial degree of spatial disaggregation. The EMPS model is the most detailed in this respect (12 regions) while NordMod-T divided the Nord Pool area into 4 countries.

A further development of the EMPS model called SAMLAST (Hornnes, 1995) represents the transmission system between areas with a physical load flow model that significantly improves the description of the power flow. Results can differ significantly compared with a simple capacity constraints representation of transmission.

In the studies using NordMod-T, it was concluded that the construction of cables were important for the results of CO_2-emissions.

Kraftsim consider the total Nord Pool system as one area without any transmission constraints between regions, except imports/exports to the continent.
In relation to the CO_2-controversy, this simplification is justified by the fact that the resulting price differences that occur between regions can be significant over short time intervals, but are less significant (on average) in the long run.
Ongoing work at WSU has established a long-term system dynamics model of the Western grid, including a 5-node power flow model (Dimitrovski et al. 2004) showing that it is possible to represent the transmission system in a power marked system dynamics model.

Second, diurnal patterns and the dispatchability characteristics of generation technologies have been found to be important for the operations of transmission lines and should thus be included in order to get a good picture of exchange between areas with different characteristics. None of the models adequately represent dispatchability characteristics of generation technologies.

8.3 Dispatchability features

Kahn et al. (1992) demonstrates that dispatchability features such as start-up and stop costs are important for the economic profitability assessment of a project in a competitive market. nuclear and coal can only slowly adjust generation and are thus run as baseload units. Coal fired units would need 6 hours from cold start till max generation. Gas and peak load turbines can adjust generation can quickly adjust generation and can be used for load following.

In a detailed unit-commitment model, start-up and stop costs gives a more realistic picture of the generation of each technology. Larsen (1996) used a detailed unit commitment model of Preussenelektra (now a part of E-ON) to study the operational implications of power exchange between the Norwegian hydropower system and Germany connected through a transmission line.

The unit commitment model included start-up and shutdown costs for Preussenelektras units. The results showed that power exchange between Norway (hydropower dominated) and Germany (thermal dominated), will result in a shift towards higher utilisation of baseload (coal) at the expense of medium- and peak load units (gas). The reason for this is that coal units are cheaper in operation, but less flexible than medium- and peak load units. Increasing power exchange with a hydropower system will then substitute generation from some of the intermediate and peak load units during exports at peak hours from Norway, and maintain an increased level of generation from coal during off peak hours that can be exported and stored in the hydropower system.

Both EMPS and NordMod-T represent demand load in terms of load duration curves (load blocks) which makes it difficult to incorporate start/stop costs that needs a chronological representation of load. Kraftsim on the other hand, has a chronological representation of load, but an hourly resolution with a description of start/stop costs of generation units has not been implemented yet. Consequently, none of the models deal with technology specific dispatch features that may be important for generation scheduling and consequently CO_2-emissions.

These shortcomings must be kept in mind when considering simulations involving power exchange between hydropower dominated and thermal dominated systems.

[figure of price differences, Nord Pool Areas]
[figure of Nord Pool Spot price versus EEX spot price]

9 Discussion of modelling approaches

Good models are designed for specific purposes - huge amounts of time have been devoted to developing such energy models. However, using models on problems outside the scope of their original purpose inevitably cause omission of important cause-effect relationships while disproportionately addressing others.

The EMPS model (originally developed for hydro scheduling and seasonal price prognosis) only captured the short-term substitution effects, while investment substitution effects were not discussed in the model studies.

Nordmod-T can in principle capture investment substitutions, but wind power was exogenously represented in the simulation runs used for the analysis. Consequently, the investment substitution effects were not sufficiently captured.

Kraftsim was particularly designed to analyse long-term versus short term implications of energy policies captured the both substitution effects. The model did not represent transmission constraints except for export/imports to the continent.

None of the models captured dispatchability features that are important for results on power exchange between thermal and hydropower dominated systems. Including dispatchability features will most likely reduce the substitution effect of exchange to the continent, which was a major contributor to the results, particularly in the EMPS and the NordMod-T study.

The modelling concept used here avoids this problem by being more of a flexible modelling concept in which the model structure is tailored to the specific problem of interest.

10 Conclusions

The results presented here shows that the fuel substitution strategy is a double-edged sword. On one hand, substitutions in generation may reduce CO_2-emissions. On the other hand, investment substitutions may (in the Nordic case) substitute future investments of renewables, and stimulate demand increases.

Could these results apply to other electricity markets than Nord Pool? Data used here are specific for the Nordic countries, where renewables are becoming close to competitive and environmental regulations are strictly enforced.

The short-term substitution effects depend on the short run marginal costs (SRMC) of the technologies (i.e. SRMC supply curve), that can differ from country to country. Nuclear and coal should not differ significantly between countries, the price of natural gas may differ from country to country, although gas markets such as the EU market for gas will in the long run reduce such price differences. The vintage of the production capacity will also be of importance.

Concerning the investment substitution, this effect will heavily depend on the countries energy policy and availability of resources. The Nordic countries possess good wind resources and wind energy is now close to competitive. In addition, renewables are subsidised. This may not be the case in other countries with less renewable resource potential, natural gas is expensive, and coal may be an alternative for new investments.

But in many market where now renewables is a realistic option for investment, and where coal is becoming less attractive due to CO_2-quota obligations - this study warns of the fuel substitution effect as being a counterproductive environmental policy as means of reducing CO_2-emissions in the long run.

Notes

1. Seasonal price variations (Chapter 7.7.1)

A more precise estimation of water values will reduce seasonal price variations somewhat, and the model data needs to be improved in this respect. As the electricity market become tighter, larger seasonal price variations can be observed. During the simulation run, the supply curve of generation technologies changes towards less peak load units and less thermal baseload. The relative share of the flexible hydropower also diminishes, and the share of wind power increase.

2. On boom/bust cycles (Chapter 7.7.1)

Potential boom and bust patterns in the electricity industry has been studied by Ford (1999,2001) and Bunn and Larsen (1992). The underlying cause of the oscillations appearing in this study however, differs slightly from the previous studies. Firstly, acquisition of capacity in previous studies was determined by a demand forecast, where the construction pipeline was taken into account to various degrees. Secondly, the models focused on capacity construction of mainly combined cycle gas turbines (CCGT), as they are currently the cheapest technology for investments. In contrast, the simulation model presented here, considers investments to be made purely on profitability criteria (for which expectations of long-term electricity prices plays an important part, see chapter 7.2). Furthermore, there are nine different technologies to choose among, each with costs changing in response to technology progress, price, fuel costs and resource availability, and with different lead times in application processing and construction. Patterns of boom and bust (shown as price oscillations) (compare LRMC's in *Figure 16*).

A previous version of the Kraftsim model (Vogstad et al, 2003) with only one vintage, and a fixed marginal cost curve for each technology did not exhibit similar patterns of boom and bust. The model was however internally inconsistent since new investments would alter the shape of the supply curve for each technology as new, more efficient plants replaced old units.

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Appendix 1 Data on existing capacity and marginal costs for the Nordic power market.

ref1999							CO2-avgift [kr/tCO2]		125
							Utslippsfaktor CO2	CO2-avgift	Produksjonskostnad inkl. CO2-avgift
Type nr	Produksjons profil	Navn	Brensel	MW	kr/MWh	GWh målt	[tCO2/GWhel]	[kr/MWh]	kr/MWh tot
		Nord-Sverige							
20	refer	kvo Fjernvarme	olje	54	110	147	350	44	150
21	refer	kvb Fjernvarme	bio	48	170	112			
22	refer	kvb Fjernvarme2	bio	14	170	37			
30		koo Kondens	olje	10	250		700	88	340
31		koob Kondens	olje	10	250		700	88	340
35		gtgd Gassturbin	gass/dies	8	420		1000	125	550
36		gtgd Gassturbin2	gass/dies	7	420		1000	125	550
				151					
		Syd-Sverige							
20	varme	kvbo Industri	bio/olje	841	55	4500	700		
9	refer	kj Kjernekraft	kjernematr	10052	70	71258	(vurdert)		
30	refer	kvk Kraftvarme	kull	642	90	1210	820	103	193
31	refer	kvko Kraftvarme	kull/olje	641	100	1048	700	88	188
32	refer	kvg Kraftvarme	ng	292	100	466	400	50	150
33	refer	kvo Kraftvarme2	olje	188	110	488	650	81	191
34	refer	kvkb Kraftvarme2	kull/bio	215	130	414	400	50	180
35	refer	kvb Kraftvarme2	bio	167	170	319	0		
40	varme	koob Kondens	olje/bio	415	250	200	700		
45	varme	gtgd Gassturbin	gass/dies	180	420	10	1000	125	545
		Totalt		13633		79913			

									CO2-avgift	125
								Utslippsfaktor CO2	CO2-avgift	Produksjonskostnad inkl. CO2-avgift
Typenr	Type	Navn	Brensel	MW	kr/MWh	GWh El	GWh varme	[tCO2/GWhel]	[kr/MWh]	kr/MWh tot
		Jylland og Fyn (DANM-VEST)								
50	refer	Vindkraft		1105	Prioritert	2050				
20	refer	Desentral kraftvarme		1374	Prioritert	6000		500	63	
21	varme	Deponigass	gass	44	Prioritert	205	511	431	54	
22	refer	kvk Esbjærg	kull	616	107	2165	1272	789	99	206
23	refer	kvk Studsrup	kull	700	118	3103	2629	854	107	224
24	varme	kvk Vendsyssel	kull	681	119	1565	446	883	110	230
25	refer	kvk Fynsverket	kull	673	119	2318	2735	866	108	227
26	varme	kvk Ensted	kull	633	115	4533	258	849	106	221
27	refer	kvg Skærbæk	ng	400	155	1496	831	450	56	212
		Subtotal		6226		23435	8681			
						21385				
		Sjælland (DANM-ØST)								
	refer	Vindkraft		321	Prioritert	550				
20	refer	Desentral Kraftvarme		466	Prioritert	2000		500	63	
25	refer	kvko Avedøre		250	113	1596	1769	833	104	217
26	refer	kvko Amager		522	121	2295	2733	865	108	229
27	refer	kvko Aasnes		1382	120	5356	511	800	100	220
28	varme	kvko Stignes		413	128	1247	3	931	116	244
29	refer	kvk Østkraft		97	166	99	102	1149	144	309
30	refer	kvgo H.C. Ørsted		249	209	337	1531	587	73	282
31	refer	kvg Svanemølle		166	218	289	1184	508	64	282
35	varme	gto Masnedø		70	355	0		1288	161	516
36	varme	kvo Kyndby		672	1396	29	0	5062	633	2029
				4608		13798	7831			

Back to the Top