The transition from fossil fuelled to a renewable power supply in a deregulated electricity market

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Abstract

In this paper, we investigate the trade-offs between long-term and short-term effects of energy planning within the context of a deregulated power market. The purpose is to find efficient policies that can aid the transition from a fossil fuelled to a renewable based power supply. Our case study is on the Nordpool power market. The model focus on the main feedback loops that determine long-term development for new capacity, namely the unit commitment (operational characteristics), capacity acquisition, technological progress and finally resource depletion. We show that the operational characteristcs sometimes are important to include in long-term analyses also in long-term analyses. Finally, some simulation runs for two possible policies are presented and discussed.

Introduction

While deregulation sweeps across the electricity sector, another important change is taking place - the transition towards a renewable energy supply.
The roles of renewables play a prominent role in all the Nordic countries' stated energy plans. Our hydro, wind and biomass resources are plentiful, and the availability of these resources played a crucial role for 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 energy intensive industry (Hydro, Elkem). The paper and pulp industry in Finland and Sweden make extensive use of bio energy resources. Nuclear power came into use in Sweden and Finland, but was stopped in Denmark and Norway. Denmark relies heavily on fossil fuels, but their Energy 21 plan aims at phasing out fossil fuels, converting to a renewable based energy supply within 2050 (Energy 21). Sweden also formulated similar targets for a long-term sustainable energy supply (SOU,2001). The present situation of the Nordic power supply is summarised in Figure 1.

The Nordic electricity market (NORDPOOL) was first introduced in Norway 1991, then expanded with Sweden in 1996, and does now include Norway, Sweden, Finland and Denmark. The power market was initially established to improve the lack of economic efficiency in the power electricity sector, as pointed out by economists (Førland, 1976). Furthermore, large benefits could be obtained by better coordination of the production capacity between countries. Harmonization of tariff structures, taxes, and energy policies is a continuation of the deregulation process, as well as new regulatory market based mechanisms (i.e. CO2-quota markets, Tradable green certificate markets, etc) that can replace the former tax/regulation policies.

In this paper, we will examine the long-term transition from *fossil fuels* to a *renewable*

	NOR		SWE		DEN		FIN		Total	
Supply	1999	2010	1999	2010	1999	2010	1999	2010	1999	2010
Hydro [TWh]	115		63				14.5		192.5	
Wind P [TWh]	-	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/y]	120	123	143	152	34	37	73	85	370	397

Figure 1 Installed capacity in the Nordic countries, 1999. Scenario 2010 according to political targets in accordance with each country's energy plans . (Source: Vogstad et al., 2001)

electricity supply within the context of the Nordic power market by examining the main feedback mechanisms that determine the development of new capacity in a deregulated power market.

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The use of models in long-term energy planning

The electricity sector makes extensive use of computer models in most of their activities. Figure 3 shows some examples of the models presently in use distributed along a time scale. At left, component design and stability analysis heavily depend on dynamic simulation tools such as Simpow (not to be confused with Powersim). In production scheduling and power trading, a number of short-term optimisation tools are used. For long-term energy planning, techno-economic partial equilibrium models are used, such as Markal and Nordmod-T. each tool only addresses a few of the feedback mechanisms relevant for long-term energy planning, because the models involve optimisation methods that require simplified mathematical representations. For this reason, these long-term models usually omit some important feedback mechanisms.

Such relationships are then left to the decision maker'policymakerss own personal judgement, and too often, this is how the controversies arise. For instance, policymakerse emphasize short-term effects and long-term effects differently. For instance, some argue that substitution from coal to gas is the more cost-effective environmentally sound policy whereas others argue that renewables might be more costly in the short run, but will be

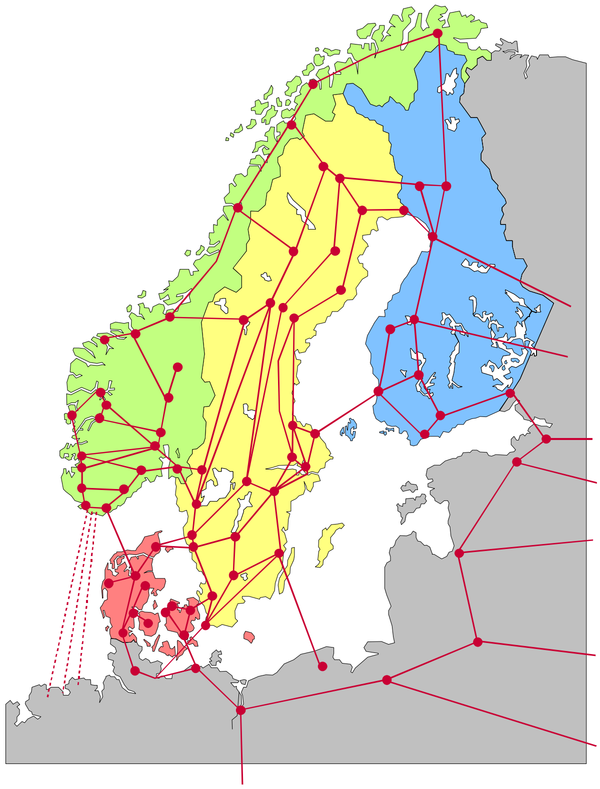

Figure 2 The Nordpool power market area: Norway, Sweden, Finland and Denmark. Transmission lines to Russia, Poland and Germany

more cost-effective in the long run, when the learning curve effect is brought into the equation.

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Using the system dynamics approach, we try to capture the main feedback mechanisms we believe are important for our problem (and that often cause controversies), to find efficient policies to support the transition from a fossil fuelled towards a renewable based electricity supply .

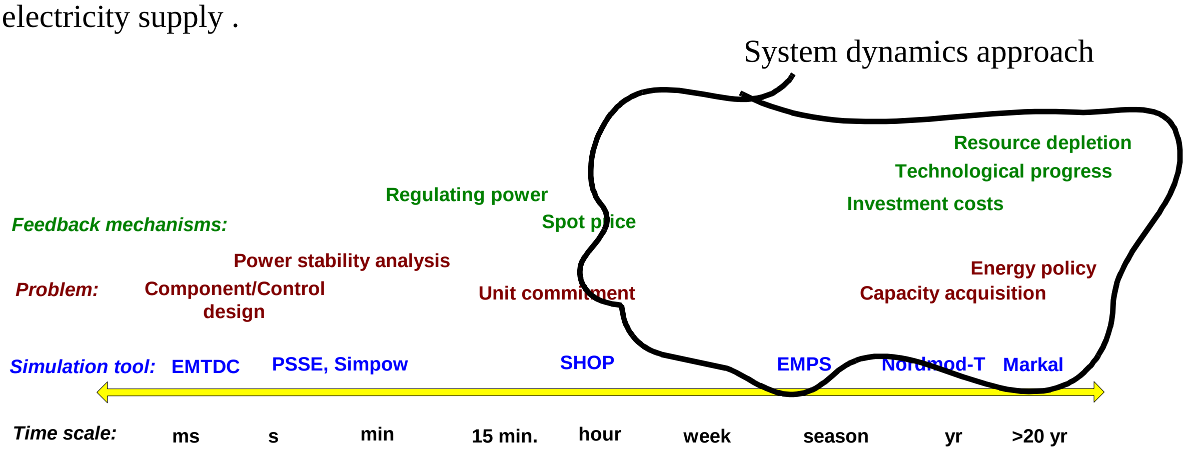

Figure 3 Energy models for decision support distributed along the time scale. Simulation tools (blue row), Problem for decision support (red rows) and feedback mechanisms included in our dynamic power market simulation model (green rows).

The power market model

Our model is a system dynamic representation of the Nordic electricity market with emphasis on the supply of various competing generation technologies. *Power generation technologies* consist of the four main technologies hydropower, wind power, biomass and thermal power. Thermal power consists of nuclear, coal, gas and peak load units (usually gas turbines). These technologies possess different economical, technological and environmental characteristics in terms of investment and operational costs, operational characteristics, emissions, resource potential and potential for technological progress.

The common Nordic Power Market[1] settles the market spot price for each hour, which is the most important information for decision makers on the supply. Additional market based services could be the TGC market and the CO2-quota market, plus the already existing futures market where long-term power contracts are made, and the power balance market.

Finally, the availability of resources ultimately limits the development of each technology. The potentially available resources for each technology are described through the resource availability sector.

Constraints on transmission capacity between the various regions are not considered in this model. Transmission constraints will for sure give rise to stronger price variations, thus imposing transmission constraints will tend to amplify the mechanisms caused by the feedback loops in Figure 4.

The time horizon is long enough for long-term impacts to take effect, while time resolution should be sufficiently small to capture the short-term mechanisms that we would chose to include. For this reason, we have chosen a 30-year time horizon, allowing the resource availability and technological progress of energy technologies make an impact. Time resolution must be sufficiently small for electricity prices to adjust the demand/supply balance over the year. By doing this, we are able to simulate the capacity factor (utilisation time) for each generation technology, because it is important for the profitability and hence new investments in capacity. Wind power and hydropower will generate power even at low spot prices, while fossil fuels are characterised by their fuel costs. Therefore, the share and seasonal variation will determine how much of the capacity is utilised during a year.

Our focus is on the supply side of the Power Market, and the demand side is therefore less detailed. However, we try to capture some of the characteristics that are of importance for price formation: Underlying demand growth and price elasticity of demand. Different developments in demand can be assessed by sensitivity analysis. In fact, there are few strong feedback mechanisms between the demand side and the supply for electricity.

1. For more infomation about the organisation of Nordpool, see www.nordpool.no

Feedback loops

On the supply side, several feedback loops determine the development of installed capacity and electricity generation for each technology (see Figure 4).

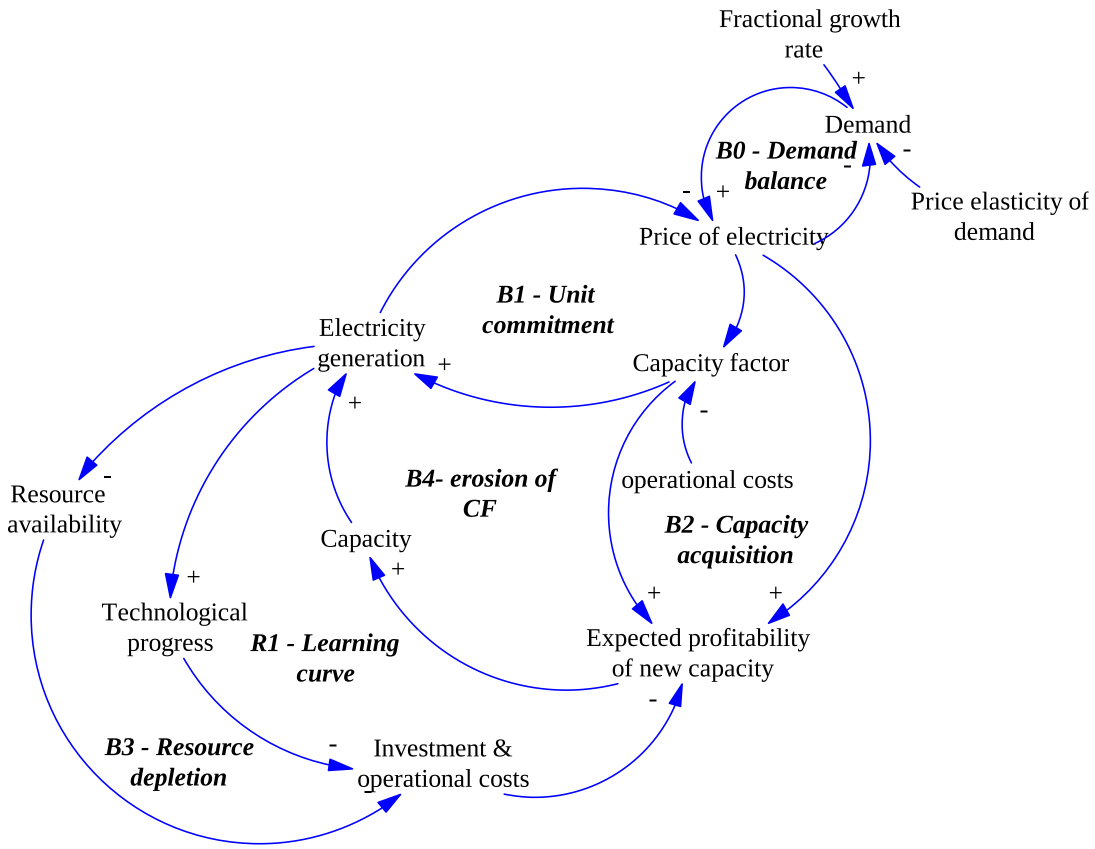

Figure 4 Main loops of the electricity supply side

Unit commitment (B1) is the process of operating units hour by hour to serve current demand loads. Generating units with the lower operational costs are commissioned first and the units with the highest marginal costs are the last units to be commissionedned. The last unit in operation determine the spot price at each time point.

Capacity acquisition (B2) is the process of new capacity investments based on the expected of profitability of new capacity additions. Long time delays are involved in this process, because applications must be sent to the regulating authorities, before new developments can be made. This process could take several years, so price expectations are based on forecasts several years ahead. The process of developing new capacity varies depending on technology type. Expansion from hydropower typically is a tedious process, because a large number of stakeholders are involved. Less time delays are involved in wind power and biomass, with usually fewer stakeholders.

The learning curve effect (R1) is a reinforcing loop, which is more prominent for the wind power and other new renewables, than for mature technologies such as fossil fuels and hydropower, although improvements are also made within these technologies. Moxnes (1992) shows how positive feedback loops of learning curves can be used in policymaking

Resource depletion (B3) is the ultimate limiting loop. Potentials for large-scale hydropower are almost exhausted in the Nordic countries, while it is assumed that the availability of fossil resources does not constrain thermal energy generation within the time horizon of our model, due to the large gas resources in Russia and Norway. On the other hand, availability of windy areas do however constrain the development of onshore wind power - but offshore potentials for wind power provides new (yet more expensive) opportunities.

Erosion of capacity factor (B4) is one possible mechanism that could speed up the downsizing of thermal generation. We will address this issue later on in the model description of each technology (cross-reference to that section). If the capacity factor (that is, the utilisation of capacity) remains low, that capacity will most likely be retired before the end of its economical lifetime. Hence, the capacity factor influence the construction and retirements of thermal capacity - which was the motivation for including the unit commitment loop in our long-term simulation model.

In the following section, we will give a more detailed description of each sector in Figure 5, starting with the capacity acquisition of each generation technology. The layers of power generation technology illustrates that there is one structure for each type of technology, and there are some structural differences between these.

Capacity acquisition

Figure 6 shows the process of submitting an application to develop new capacity, whereupon the application is processed. Approved applications can then be developed into new capacity that comes on line. This process is highly regulated and involves long time delays, depending on technology type. For instance, the process of developing new hydropower plants could take several years, because of all the stakeholders involved (NGO's, local authorities, national authorities. The final decisions are often made by the parliament. Also, thermal generation such as nuclear, coal - and even gas power catches public and political debate in each of the Nordic countries. A final decision is now being made regarding expansion of nuclear power in Finland; Sweden are discussing how fast the nuclear power should be faced out, as the parliament decided to phase out their nuclear power. In Denmark, no new coal-fired plants are approved, and areas for onshore wind power are scarce. One Norwegian government resigned as they refused approving the first land-based Norwegian gas power plant[1]. By the time applications finally are approved, the profitability of the project may have changed, or new environmental requirements have made the projects less attractive. The reject fraction and projects abandoned are exogenously determined.

1. The Norwegian power supply is 100% based on hydropower, except the offshore installations, which is supplied by gas power.

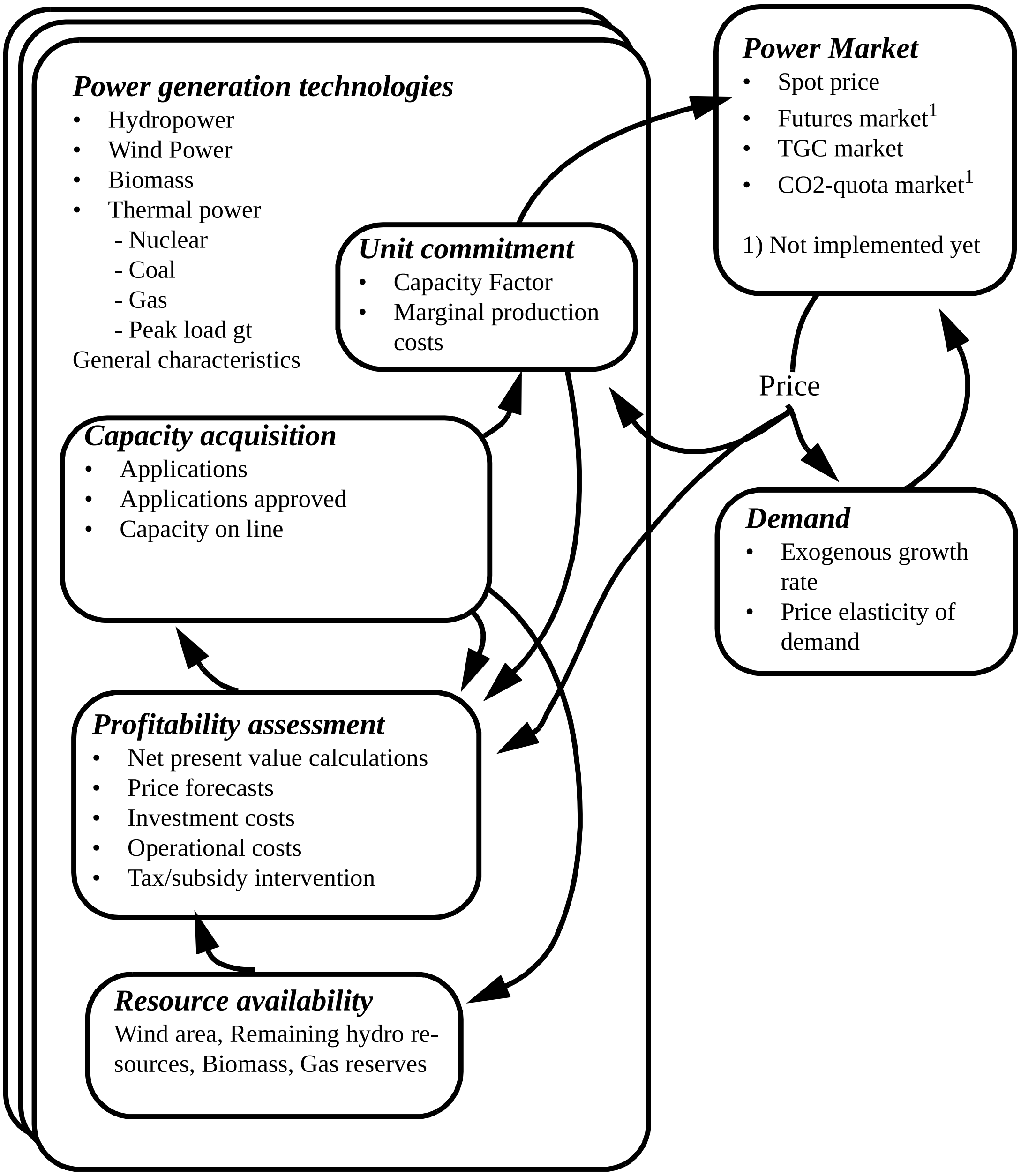

Figure 5 Structure of the model, subdivided into sectors.

The initial values, starting from 2000, are set so that the supply line is in dynamic equilibrium, that is, the initial application rate balances the discard rate when the effect of profitability on application rate is 1 (see definition of Effect of profitability on application rate in the *Capacity acquisition* section). Construction time and application processing time typically varies from technology to technology, the shortest are for biomass and wind power, (about 1/2 a year), while the longest time delays are for hydropower (3 years application processing time, 3 years construction time)

Reinvestments in existing capacity are not included in our model, although it might be necessary to include the vintage structure of the rapidly developing wind power technol-

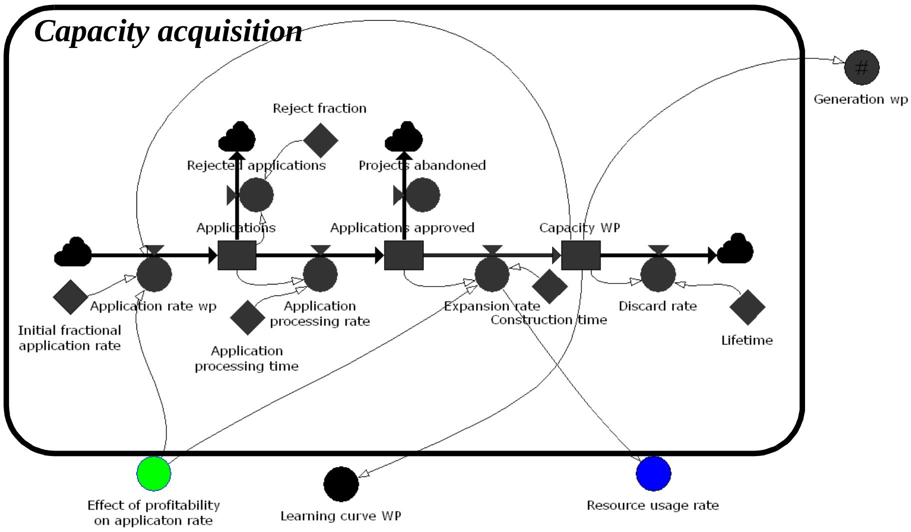

Figure 6Capacity acquisition, taking wind power as an example.

ogy. The technological performance of this fast growing technology changes significantly over the time period, and new turbines require much less area compared with older ones.

Profitability assessment

The variables involved in the profitability assessment are displayed in Figure 8. Profitability of new capacity investments depends on the one hand on expected future spot prices, and on the other hand on investment costs, operational costs and expected capacity utilisation. The learning curve reduces investment costs, and operational costs.

Energy investment costs = Investment costs * learning curve / (lifetime * max full load hrs * CF) [NOK/MWh]

Profitability indicator = (Expected electricity price - operational costs) / Energy investment costs. [NOK/MWh]/[NOK/MWh]

The profitability indicator is held against the required return on investment for that technology, where we used 7% interest rate and 20,30 and 40 years expected lifetime of wind, natural gas and hydropower respectively. Required return on investment and profitability indicator has the same interpretation as the annuity factor. Finally, these two factors are used in the “Effect of profitability on application rate” :

Effect of profitability on application rate = graph(Profitability indicator /Required return on investment)

There is surprisingly little theory or information to obtain from standard economic literature on this relationship. Morthorst (1999) made an empirical estimation of this relationship on wind turbine owners in Denmark, and came up with an s-shaped curve for private-owned turbines. There was no similar study for other generation technologies available.

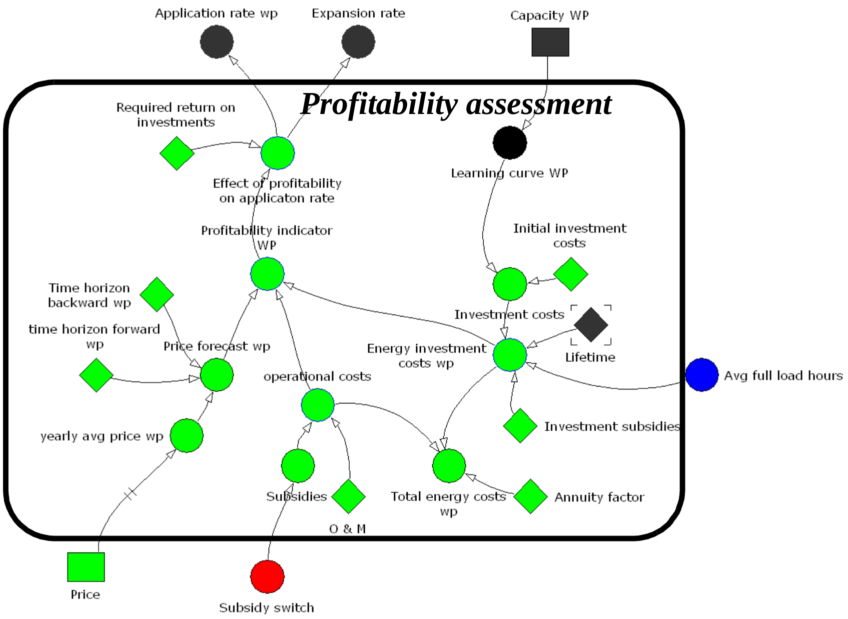

Figure 7Expected profitability of new capacity. Profitability depends on spot price, expected capacity utilisation, subsidies and the learning curve. Costs are divided into investment costs and operational costs. Market prices are forecasted based on previous values.

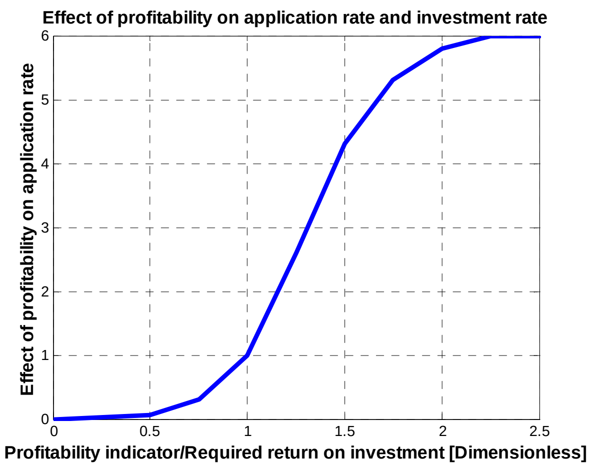

Figure 8 The relationship between expected profitability and application & investment rate

We can, however derive the shape of the curve analytically, based on some simple assumptions, see Figure 8. The relationship would represent a cumulative lognormal or normal distributed curve as the sum of the uncertain factors involved in the profitability assessment. The curve is applied on all technologies. The magnitude of this curve is limited upward so that the maximum application & investment rate is set to 30 % of installed capacity. Rapid growth within an industry is constrained by the availability of goods and services from suppliers in other sectors.

Unit commitment

The operational characteristics differ between the technologies. Thermal units are operated after their marginal costs of generation, which is roughly equal to the fuel costs. Thermal plants take spot price as an input to determine their generation level. As the prices of electricity rise, plants with increasingly higher marginal operational costs starts up until the spot price levels out.

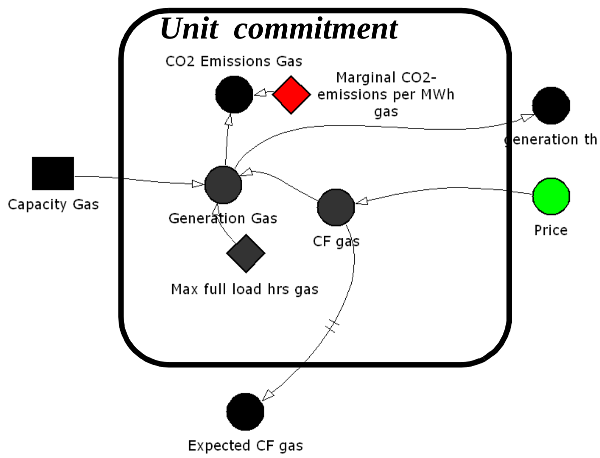

Figure 9Unit commitment. Capacity utilisation expressed by the dimensionless capacity factor is a direct function of market price.

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Utilities must decide when and how much of their capacity should be in operation. This is known as the unit commitment problem. Thermal units are run by their marginal fuel costs. We denote the fraction of capacity in operation as the Capacity Factor (CF). The capacity factor can then be calculated using the marginal cost curve of thermal energy, normalised by installed capacity. We thus assume the shape of this curve (that is, the distribution of baseload, medium load and peak load) to be fairly constant over the simulation time. At each point in time, electricity prices determine the fraction of installed capacity in operation. The unit commitment submodel is shown for gas power in Figure 9, and this structure applies to the thermal generation types (including biomass). The graphs in Figure 10 are based on Vogstad et al (2001). In the system dynamic model, the CF curves were somewhat smoothed in comparison to the the original data because the original data are aggregated.
Wind power generation cannot be controlled, and must generate power when the wind blows, although wind power can be taken into account in hydropwer scheduling (Vogstad,

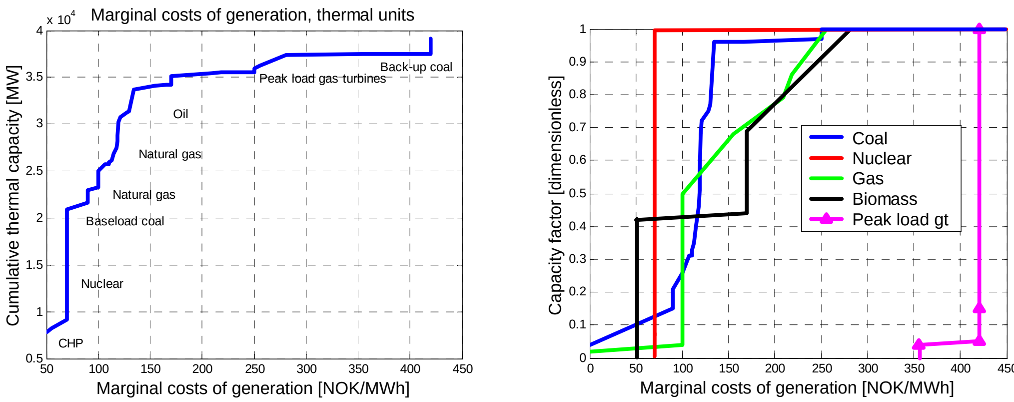


Figure 10 Marginal cost curves, thermal power, Nordpool. Left : Aggregate cost curve. Right: Marginal cost curves for each technology type.

2000) This is also the case for run-of-river hydropower. Figure 11 shows the variation in yearly hydro inflow and wind power. The right graph shows the seasonal variations in demand, hydro inflow and wind power. While wind power nicely fits the seasonal demand curve, most hydro inflow is released during the spring.. From 30-60 years of inflow data with resolution of one week, we represent the yearly variations for wind power and hydropower as normal distributed random variables with a standard deviation of 0.063 and 0.12 respectively. Our simulation runs therefore includes some stochasticity, but all the simulation runs have the same stochastic series for ease of comparison. Hydro inflow, wind and demand are in addition represented with seasonal variations using the profile curves in the rightmost graph of Figure 11.

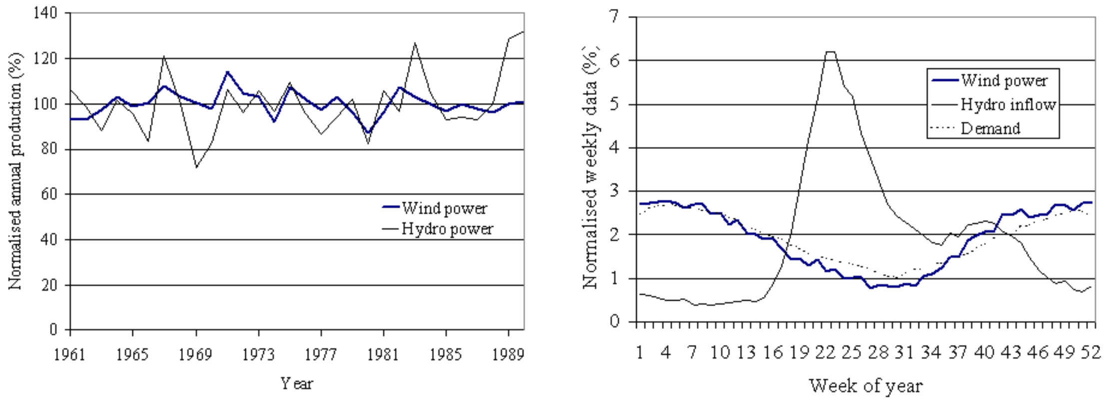


Figure 11Left: Yearly variations of hydro inflow and wind energy. Right: Seasonal variations in hydro inflow, wind energy and demand. (Source: Tande & Vogstad, 1999)

Run-of-river hydropower is very similar to the intermittent wind power in the sense that neither of these units can be scheduled for generation.
Hydropower with reservoirs, however, has the unique possibility of storing energy. The reservoir capacity is not unlimited, therefore “marginal costs” of hydropower generation

is associated with expected profits of storing the water for later use. Expected future profits that can be obtained by storing water for later usage depend on future hydro inflow and electricity prices, and present reservoir level. The method of calculating the “marginal costs” of hydropower generation is referred to as the *water value method*, and utilities use sophisticated optimisation models to accomplish this task[1]. We approximate this hydropower scheduling problem using a table lookup function of water values taking the reservoir level content as input, see Figure 13, left graph. Figure 12 illustrates the hydropower scheduling problem and the management of reservoirs

. At maximum reservoir level, the water value is 0, because you will not be able to store

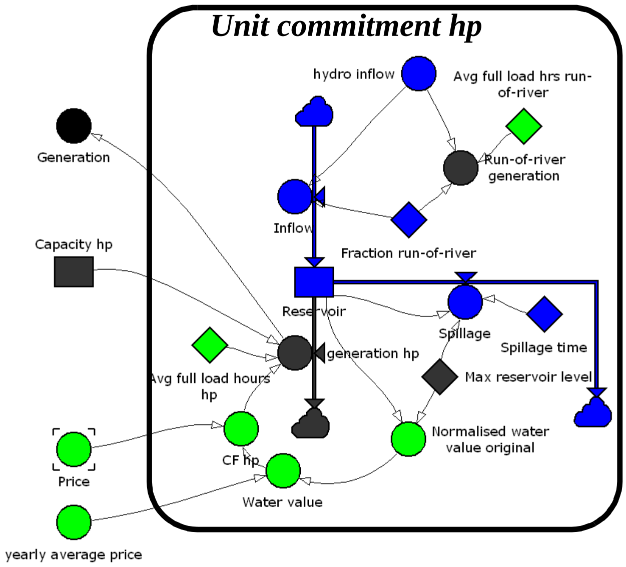


Figure 12Production scheduling (unit commitment) for hydropower with reservoirs

new hydro inflow, and the water is spilled. When the reservoir level is about to run empty, prices would rise, because there is now a scarcity of supply in the system.

The Nordpool Power Market

30 % of financial power contracts were settled through the Nordpool Power Exchange in 2001. The rest is traded through bilateral contracts. Market price clears every hour, and a number of other financial derivatives are offered, for instance the regulating power market (to balance power) and futures contracts for power up to 3 years ahead.

Price is an important input to all other sectors; unit commitment, profitability assessment and demand.

The spot price is calculated as follows:

$$\text{Price}_t = \text{Price}_{t-1} \cdot \frac{(\text{Demand}_{t-1} - \text{Generation}_{t-1})}{\text{Demand}_{t-1}} \cdot \frac{1}{\text{Time to adjust price}} \quad \text{[NOK/MWh]} \tag{1}$$

1. The energy models EOPS and EMPS mentioned in Figure 3 are actually used for this purpose

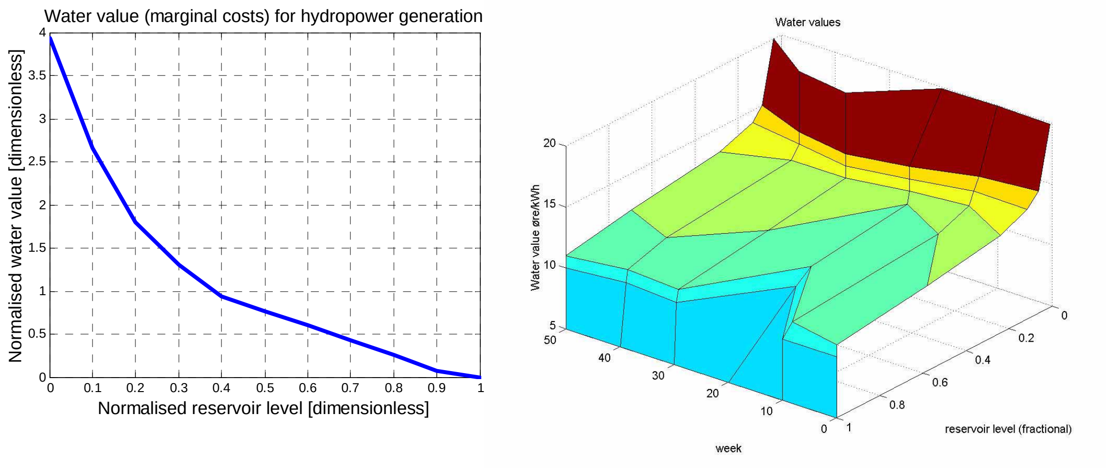


Figure 13Left: Water value column, representing water values as a function of the reservoir level. Right: Water values calculated using EMPS. The water value column varies over the season, but not dramatically.

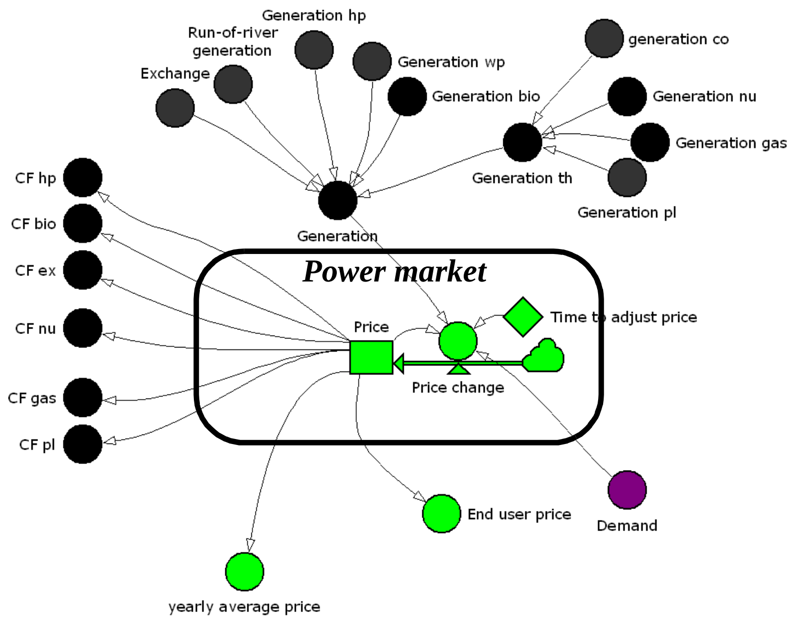


Figure 14 A dynamic formulation of price setting in the Nordpool Power Market

This represents a hill-climbing search to find the price that balances the supply/demand. The power market has some special features. The bids of demand and supply are submitted 12-36 hours in advance of market clearing. Suppliers make their bids using a supply curve. Nordpool then collects all bids and determine spot price on the basis of the aggregated curve. Market actors are then well informed about how much they are obliged to supply some 12-36 hours in advance of market clearing. If utilities fail to fulfil their contract obligations, they will be charged after hand by the power balance market. The power balance market is designed to provide generation on short notice, to adjust for imbalances and unexpected failures. The power balance market price is usually higher than the spot market, although hydropower in Norway provides a fast and cheap way to up/down regulate power. In thermal dominated systems, power for rapid up/down regulation is more expensive.

Market participants are assumed to behave boundedly rational when making decisions about new capacity investments (see the Capacity acquisition and the profitability assessment submodel). Currently, we only include the spot market in the Power market submodel. Investors will typically use the futures market to estimate long-term power prices. If we wanted to study consequences of strategic behaviour in these markets, we could extend our model with the power balance market and the futures market. Prior to that, a market for Tradable Green Certificates, and a CO2-quota market will be implemented. At present, there is no strategic behaviour of market participants, but this can be easily implemented with the dynamic representation of the spot market.

In our model, price is adjusted every 3rd day. It turns out that market balances sufficiently for our purpose, which is to give an adequate representation of the operational characteristics for the various generation types. As a result, the capacity factor CF changes due to seasonal variations of wind power and hydropower, and the interplay between thermal units with higher marginal operational costs.

Learning curves

Each technology has reached different stages of maturity. Technology progresses as the cumulative installed capacity of a technology increase, but we must keep in mind that the Nordic electricity supply is only a small fraction of the total world market for electricity, and technological progress cannot be endogenously described by the cumulative installed capacities in the Nordpool area. We therefore define an exogenous learning curve multiplier and a learning rate, k_i of technology i.

$$\text{Learning curve multiplier(t)} = e^{-k_i(t - t_0)} \quad \text{(dimensionless)} \tag{2}$$

Investment costs$_i$(t) = Initial investment cost$_i$ * Learning curve multiplier$_i$(t)

Technology $_i$	Hydro	Wind	Natural gas	Bio energy
k_i	0.002	0.014	0.05	0.008

Figure 15 Exogenous learning rate for the various technologies.

However, we take wind power as an exception. The major share of wind power development has taken place in Denmark, and Danish wind turbine manufacturers dominate the world market by 50% share. Denmark is now focusing on the offshore wind power development, and several large-scale offshore farm projects are under construction. The shallow waters around Denmark and Sweden are especially suited for the offshore wind power technology, and we assume new technological progress to be closely related to the wind power development in the Nordic countries introducing the following standard function (IEA, 2000):

$$\text{Nordic market learning curve multiplier} = \left(\frac{\text{Capacity WP}}{\text{Initial capacity WP}}\right)^{-0.2}$$

The large share of bio energy and hydropower could also justify an exogenous learning curve for these technologies, but we leave this issue for later work.

Resource depletion

The four technologies will ultimately reach limits of resource availability. large-scale hydropower has in practice reached its potential, though these limits are to some extent politically and economically determined. Further expansions must come from small-scale development.

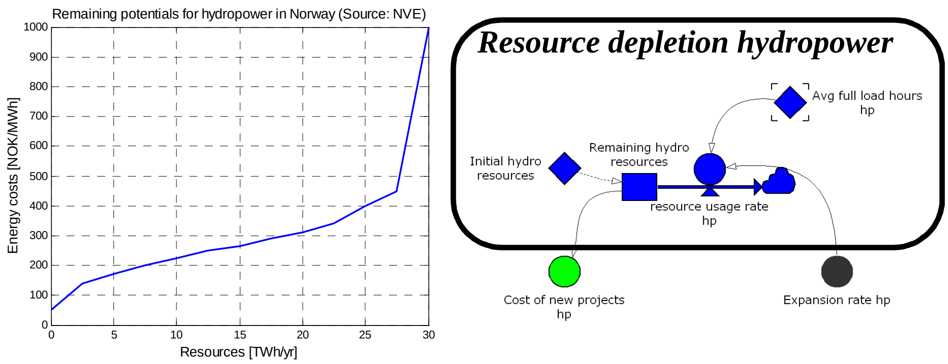


Figure 16Costs of new hydropower development in Norway. (Source : NVE)

Wind power has still a large, unexploited potential, world wide as well as in the Nordic countries. However, Denmark is about to reach its limits for land resources. Further wind power developments are taking place offshore, or by upgrading old farms onshore. When examining the vintage structure of wind power onshore, it seems possible to increase installed capacity from 2500 to 6000 MW by substituting old turbines with the new and larger turbines on existing sites. At present, the energy costs of developing offshore parks are at least 30% larger than for onshore parks. In contrast, the offshore potential is practically unlimited. The coastal areas of Norway provide good opportunities for cheap and cost-effective wind power onshore, and a recent wind resource assessment has been made by NVE[1]. The resource availability influence costs of wind power in the same way as with hydropower (see Figure 16), but differ in the sense that wind resources are measured in square km’s of windy areas. The remaining potential in turn determines the capacity factor for wind. As the more windy areas are utilised, less windy areas remain to be developed at higher costs.

1. See Vector: www.vector.no

Due to the large gas resources in Norway and Russia, we assume natural gas generation not to be restricted by resource availability during the next 30 years. Rather, environmental concerns put restrictions on emission levels and resource availability of natural gas or other fossil resources are not estimated in our model. A further

Scandinavia is largely covered by pine and spruce trees, with a large pulp industry. Different kinds of waste from the pulp industry, building materials from wood, etc, provide cheap sources of biomass for heat and electricity cogeneration. The available potential is estimated to be about 220 TWh/yr (for both energy and heating), but the costs of the sources limit the economical potential. Waste from pulp industry and other waste materials from wood are the cheapest, direct use of wood for heating a bit more expensive, and finally growing energy crops is the most expensive alternative.   The costs of biomass therefore increase as more expensive sources for biomass must be utilised.

Export

Total transmission capacity for exports amounts to 3500 MW, and can be regarded both as supply and demand. The profitability of transmission lines depends on the price differences between Nordpool and neighbouring countries. Deregulation and restructuring of the electricity sector has stopped utilities from investing in new transmission capacity. One the one hand, if the price difference between Nordpool and neighbouring countries is high, the transmission itself is profitable. On the other hand - new transmission cables will also reduce the spot prices in the Nordpool area, because the capacity not being used is available to all market participants by the Nordpool. Power intensive consumers could, however profit on building new transmission lines. A study made by Wangensteen et al (1999), concluded that it is probably not profitable for utilities to build new transmission lines under the current circumstances. Exchange capacity is therefore fixed in our approach.

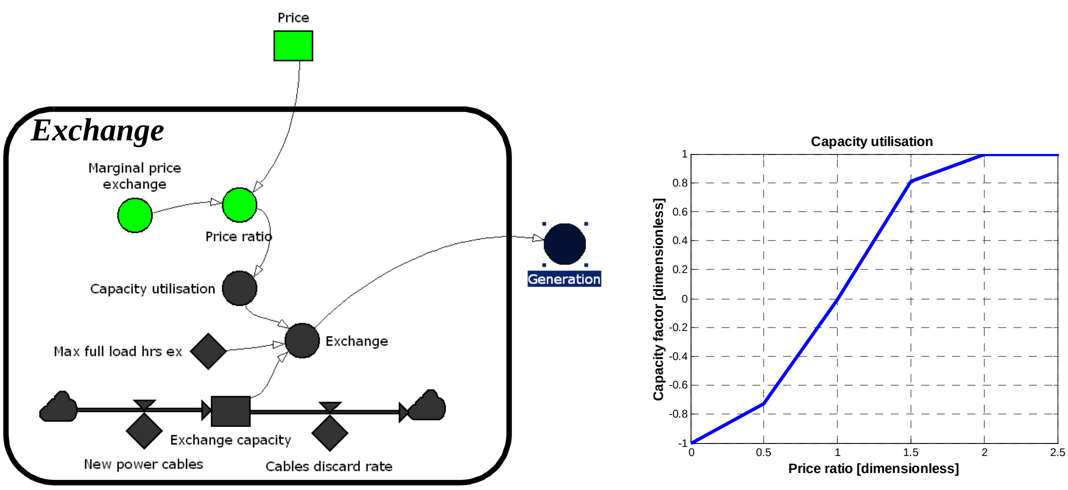


Figure 17Transmission lines from the Nordpool area to neigbouring countries. Right: Capacity utilisation as a function of the price ratio

Demand side

Our focus is on the supply side, though there are many interesting alternative options to new developments of capacity on the supply side. As a compromise, we try to capture some of the main characteristics of the demand side: *Demand variations* (seasonal), *demand growth*, and *price elasticity of demand*. Changes in demand consist of a net fractional growth rate (due to increase in population, income, etc), and a fractional price elasticity of demand. Consumers compare present end-user prices with a reference price, which is an exponential smoothing of last 5 years' end-user electricity prices. There is no distinction between different types of consumers.

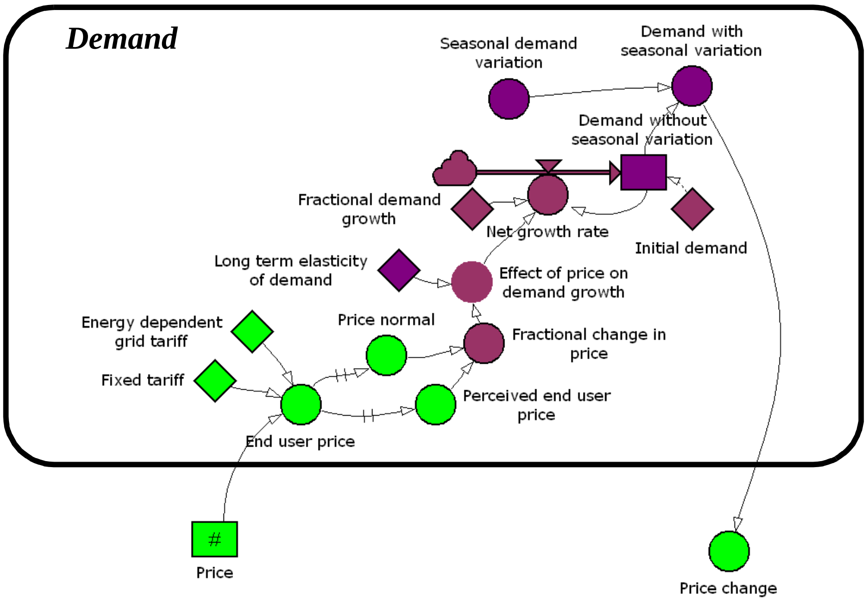


Figure 18 Demand submodel. Underlying growth and price elasticity of demand represent end-user behaviour. The end-user slowly adapts to new prices

Simulation results: Base run

In our base run, a subsidy of 70 NOK/MWh is paid to new renewables (wind power and biomass). Figure 19 shows the development of *installed capacity*, *generation* and *prices/ costs*. While nuclear power and coal power are decomissioned, wind power and gas power picks up around 2015. Bio energy shows a faster development, but peaks around 2015. Although the potential for biomass is large, the availability of cheap biomass is more restricted. Waste residuals from building materials and the pulping industry are cheap sources of biomass, but when this potential is exhausted, more expensive sources must be used, either direct extraction from the forest, or growing of energy crops. Biomass is also affected by the capacity utilisiation, which is a function of the price level. Even though technological progress improves the efficiency of biomass, other sources are more competitive in the long run of bringing the costs down.

Price increase to a higher level during the first five years. As mentioned earlier, we assume that no new nuclear or coal power is built, only gas power is from an environmental point of view accepted among the fossil technologies. The long-term energy costs of gas power were initially higher than the market spot price. Thermal power dictates the electricity price, and when the prices increase, the capacity utilisation must also increase. There is still overcapacity in the Nordpool market and we are still in the transition phase towards a power supply with a market price that will be in equilibrium with the long-term marginal costs of generation. A first insight with our model - we can expect the Nordic market prices to increase to a new long-term level equal to the long-term marginal costs of developing new gas power within this scenario.
We also observe that the total costs of wind power fall to a minimum before increasing (total costs are displayed with subsidies included). The learning curve effect drives the costs down, but as the most attractive sites are developed first, more costly and remote areas must be developed, which will increase costs in the long run. The wind power development is therefore likely to follow an s-shaped trajectory of capacity development. If sufficient technological progress is made for offshore wind power, potential areas are no longer a constraint. Other constraints, perhaps grid constraints would then be limiting factors.

The simulations in Figure 20 show the base run when variations in hydro inflow, wind energy and demand is included. As can be seen, omitting seasonal variations changes the simulation results to some extent. Simulations without seasonal variation are shown as thin lines in the same graphs. The installed capacity of wind power, hydropower and even biomass increase at the expense of gas power. In fact, the CF and expected CF are reduced due to these seasonal variations as shown in Figure 21.
The below Figure 21 shows how the supply and demand balances for each simulation run. The smooth lines correspond to the base run without seasonal variations. The oscillating lines show demand and supply when seasonal variations are present.

Figure 22 Is a close-up of the *generation* and *price* graphs in Figure 19, respectively. The lower graph displays the simulated spot price, and also includes the observed spot prices for 2000 and 2001 for comparison. 2000 was a wet year, and therefore the prices were notably lower during the first months of the year. The corresponding CO2-emissions are shown in Figure 23, both with and without seasonal variations. The CO2 emission levels, and even the behaviour, changes when seasonal variations are included due to the nonlinear operational characteristics of the unit commitment loop (see Figure 4). First, we should note the substitution from coal to gas, which will reduce the CO2-emissions for some time according to the upper brown thin line in Figure 23. However, nuclear power also needs to be replaced, and in the base run scenario, there will be a net increase in CO2-emissions after 2015. Therefore, increased efforts of increasing the share of renewables are required if the power industry is to meet the Kyoto target for greenhouse gas emissions.

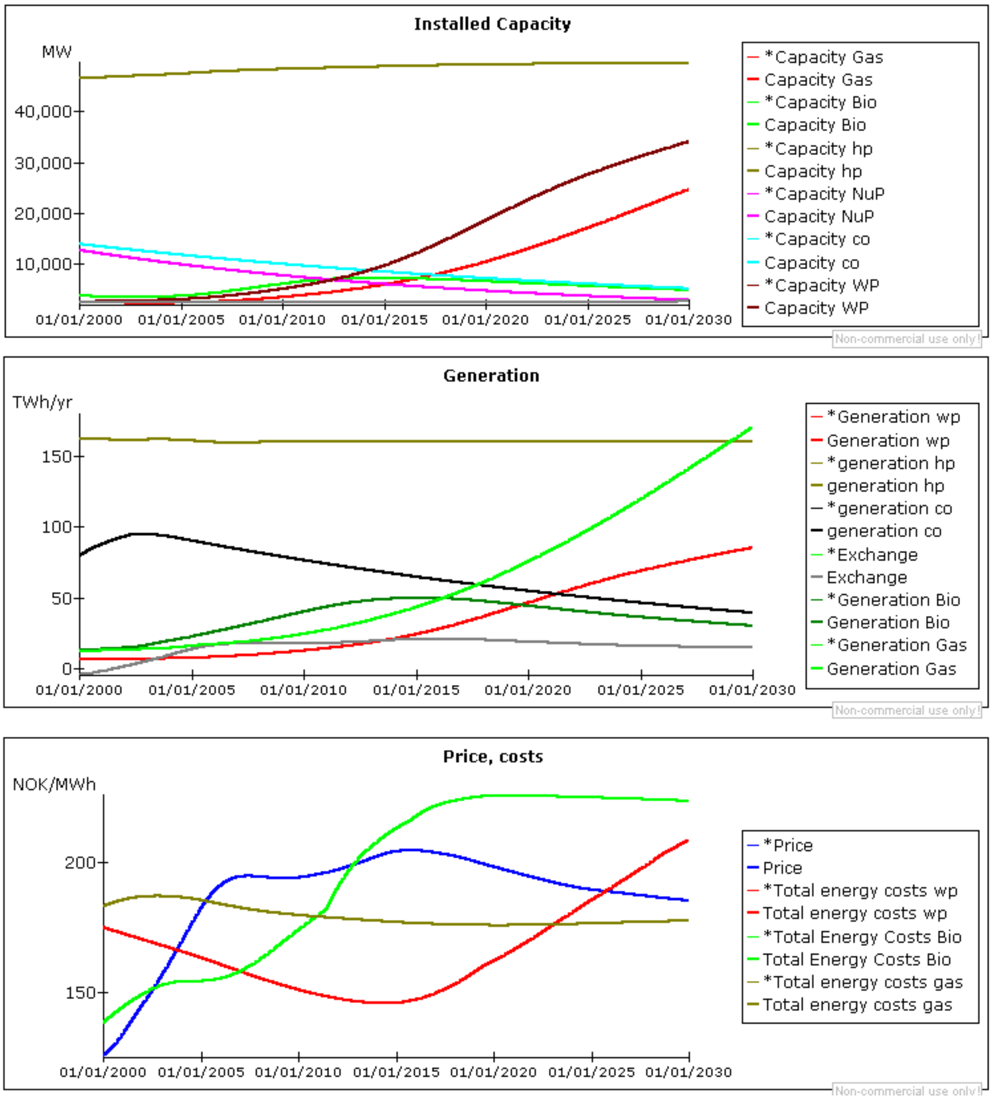


Figure 19 Base run simulation. Subsidy for wind power and biomass: 70 NOK/ MWh. Demand side as described in previous section.

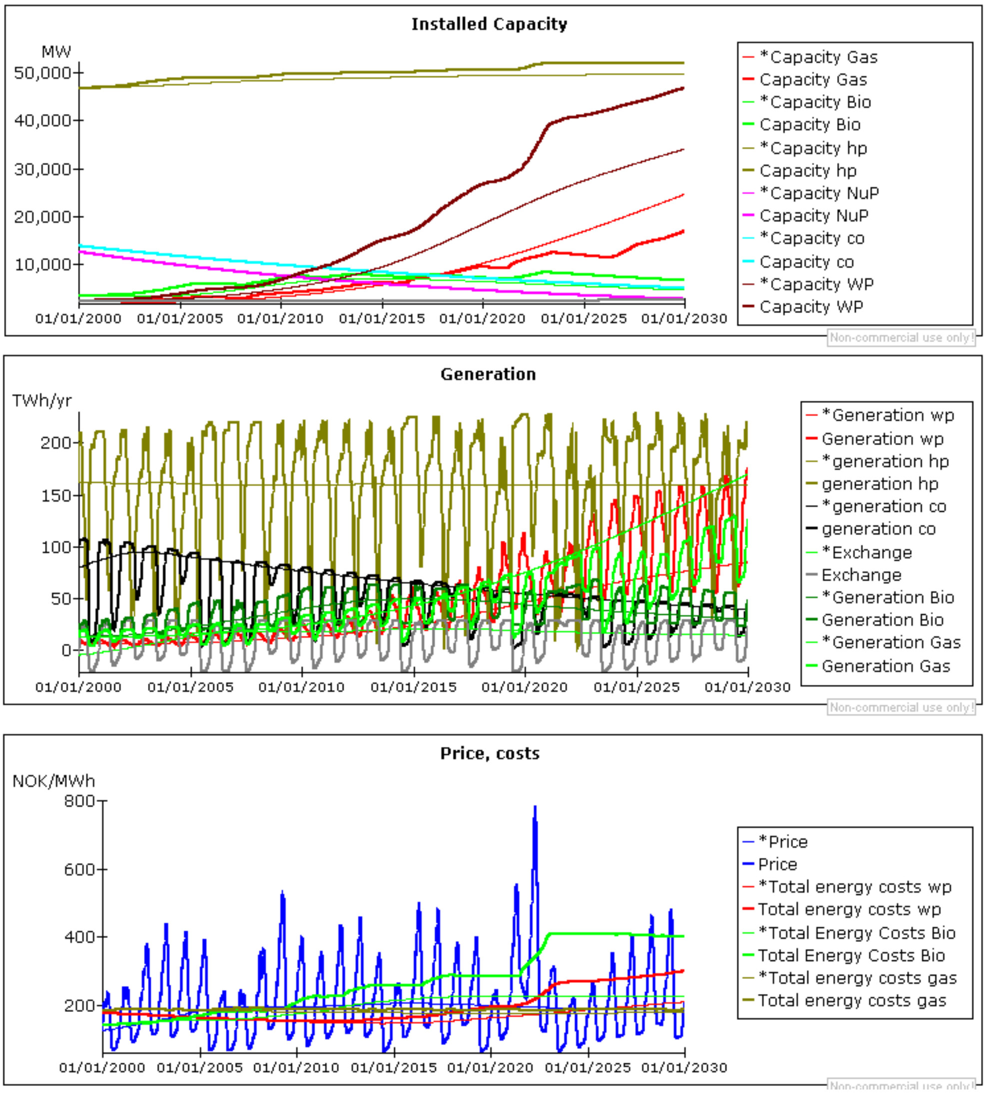
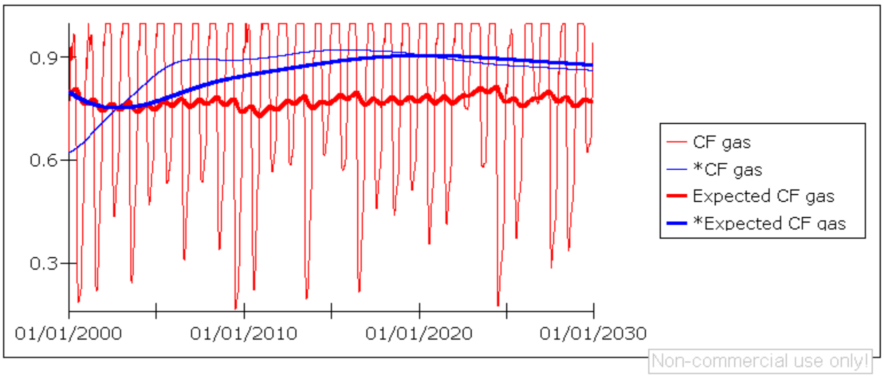


Figure 20 Base run simulation with seasonal variation in demand, hydro inflow and wind energy.



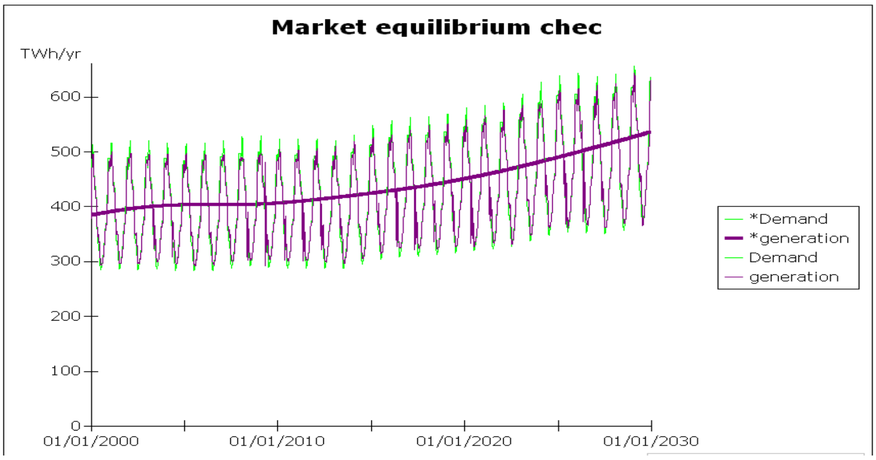


Figure 21 Capacity factor gas power. Blue lines show simulations without seasonal variations, red lines show CF when seasonal variations are included in the simulation.

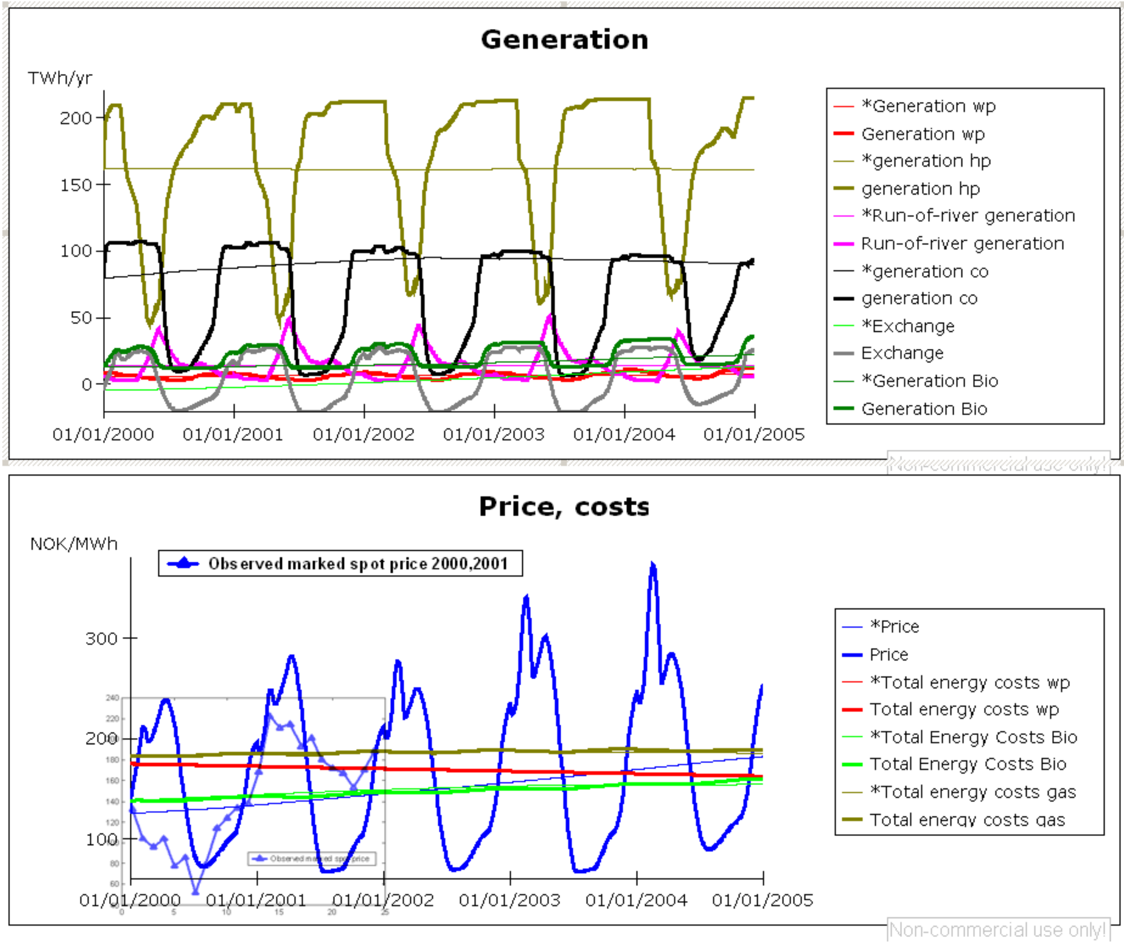


Figure 22Close-up of simulations. Upper graph shows the unit commitment of each generation technology. The lower graph shows how prices develop during the first years. For comparison, the observed Nordpool spot prices for 2001 and 2002 are included. Year 2000 was an exceptional wet year, therefore, prices were kept extremely low during the late winter and spring period. Year 2001 is more of an average year of inflow.

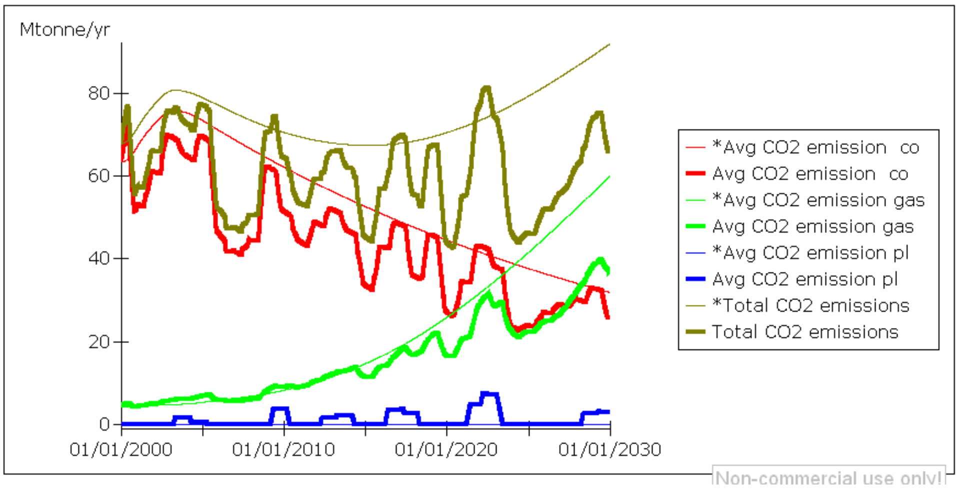


Figure 23CO2 emissions,base run. Without seasonal variations: Thin lines. With seasonal variations: Thick lines.

Policies for change

The most obvious policy instrument is tax or subsidy interventions. ExternE, a 10-year EU-study assessed the external costs of energy technologies, using risk environmental assessment as a method. The cost estimates include effects of air pollution, occupational disease, accidents and damage on natural and build environment. They used a spatial model for emissions, because damage of for instance SO2 and NOx depend on the location. Figure 24 summarises external costs of generation in the Nordic countries. Converted to Norwegian currencies, the taxes for Natural gas should be in the range of 60-640 NOK/MWh to compensate for external costs.

External costs of generation values in mECU/kWh	**Den**	**Nor**	**Swe**	**Fin**
Natural gas	7.1-80	7.7-19.2	18-42 (coal)	4.2-9.6 (coal)
Bio energy	16-4.4	2.4	1.8	6-14
Wind	0.6-3.65	0.5-1.1	-	-
Hydropower	-	2.3	0.3-54	-

Figure 24Summary of ExternE results on external costs of energy technologies. (Source: ExternE, http://externe.jrc.es/)

The effect of introducing a CO2-tax

In this next simulation run, we have imposed a CO2 tax from 2005 on, keeping subsidies for renewables at the same level. The results are shown in Figure 25 and Figure 26, where the base run scenario is shown with thin lines. We observe a development in favour of renewables, both in terms of installed capacity and in terms of generation, as was expected. Comparing Figure 26 with Figure 25, including seasonal variations changes the results in favour of more renewables. Higher price volatility is to be expected, but not significantly higher than that of the base run. Figure 27 shows how CO2-emissions drop as a result. Thin lines display base run without seasonal variations, thick lines display results with seasonal variations. The spot price will increase to a level between 200 and 250 NOK/MWh, which is somewhat higher than in the base run.

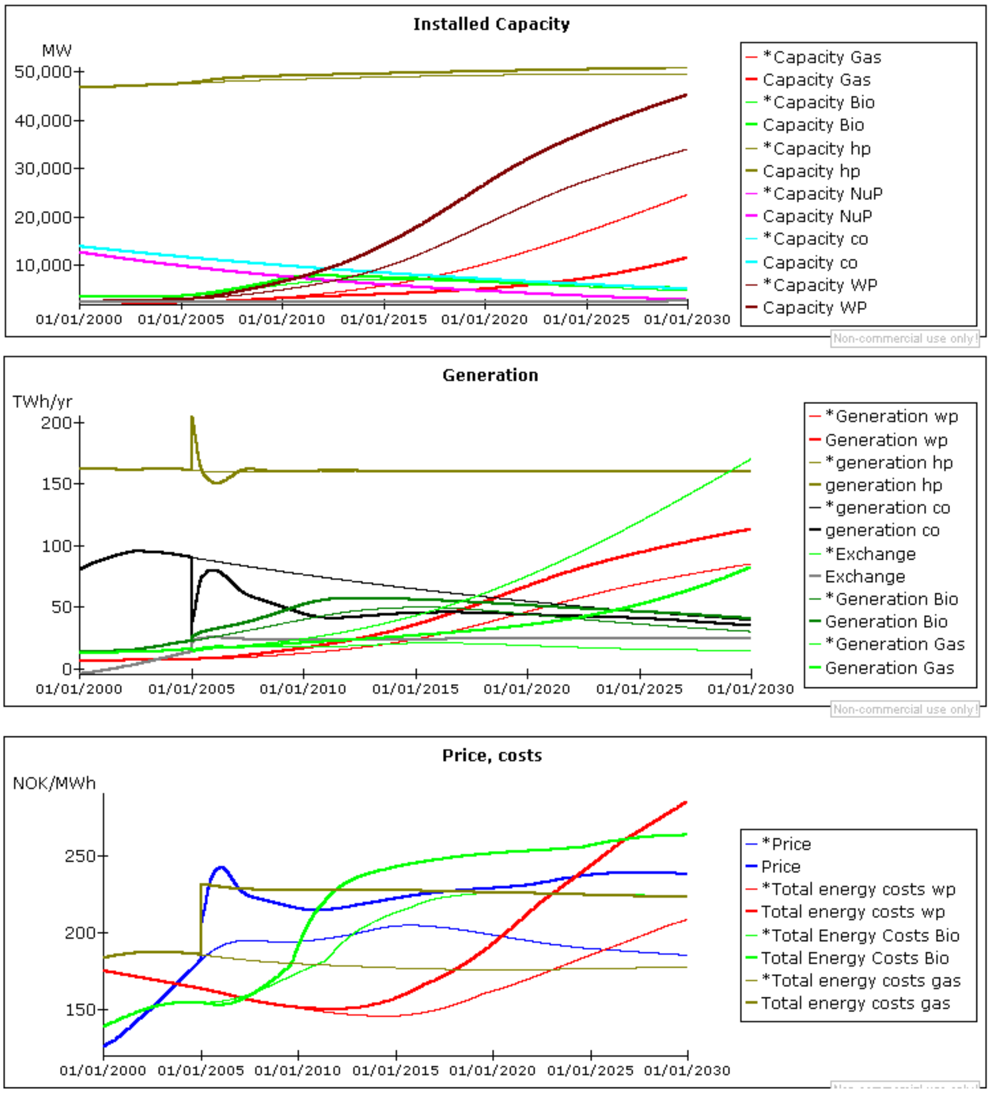


Figure 25CO2-taxes of 125 NOK/MWh imposed from 2005. Thin lines display base run values, thick line display new simulation with CO2-taxes. No seasonal variation

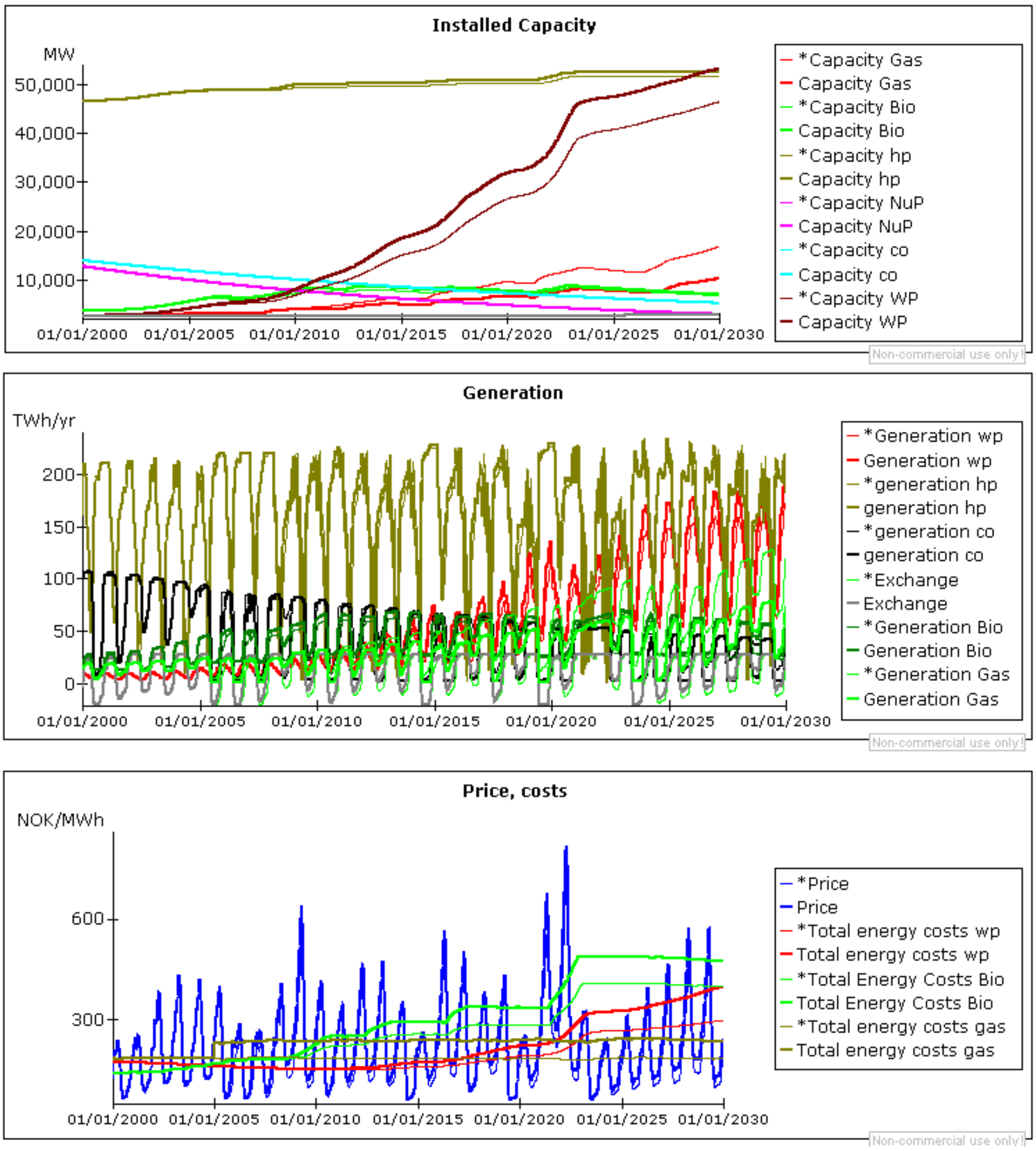


Figure 26CO2-tax of 125 NOK/MWh imposed on base run.

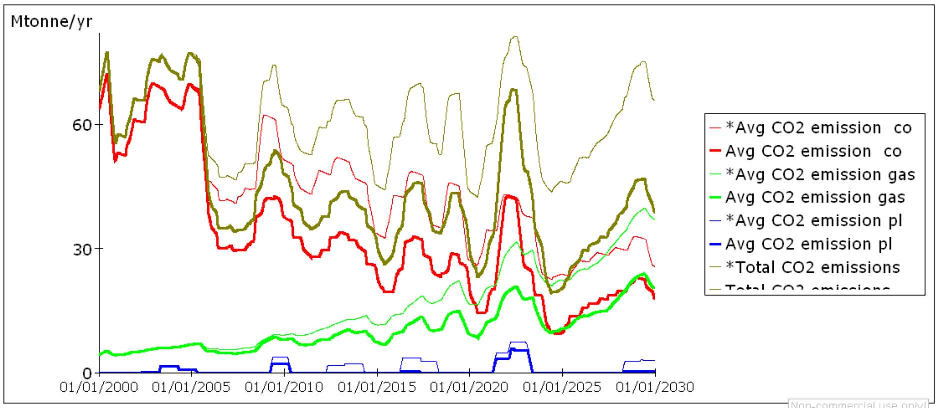


Figure 27Introducing a CO2-tax of 125 NOK/tonne (thick line). Thin line with corresponding coloursdisplay base run.

The effect of a strict regulation regime

As mentioned in the capacity acquisition section, the application procedure is a tedious process. NGO's have been especially successful in filing complaints, which will slow down the application processing rate significantly as prices go up. There are many environmental laws and regulations, both in Norway and in the EU countries that would take a long time to clarify in relation to a project. This is now the case for several Norwegian gas power plant developments, where there are uncertainties regarding obligations and new regulations. Also, wind power projects have been exposed to this strategy, if the area for development houses some protected species. The effect of slowing down the capacity acquisition chain, is a reduced capacity expansion for all technologies. This is counteracted by the increased profitability, as prices goes up. Figure 28 that when stricter / slower regulation policy has the effect of slowing down new capacity developments comparatively less gas power is developed and wind energy generation will be higher than electricity from gas by 2030. The prices risehydropowerhydropower to about 250 NOK/MWh. When seasonal variations are included (Figure 29), wind power grows even stronger and gas and biomass contribute equally to the energy mix by 2030. Even though peak load turbines are installed to keep a fixed percentage capacity margin.

Minor changes in CO_2-emissions occur, because coal power is not affected by this strategy, and CO_2-tax worked more efficiently in addressing the CO_2-problem. Because the margins in this system are smaller, price volatility increase significantly.

It is important to point out that NGO's and public opinion as stakeholders have the possibility of using this strategy.

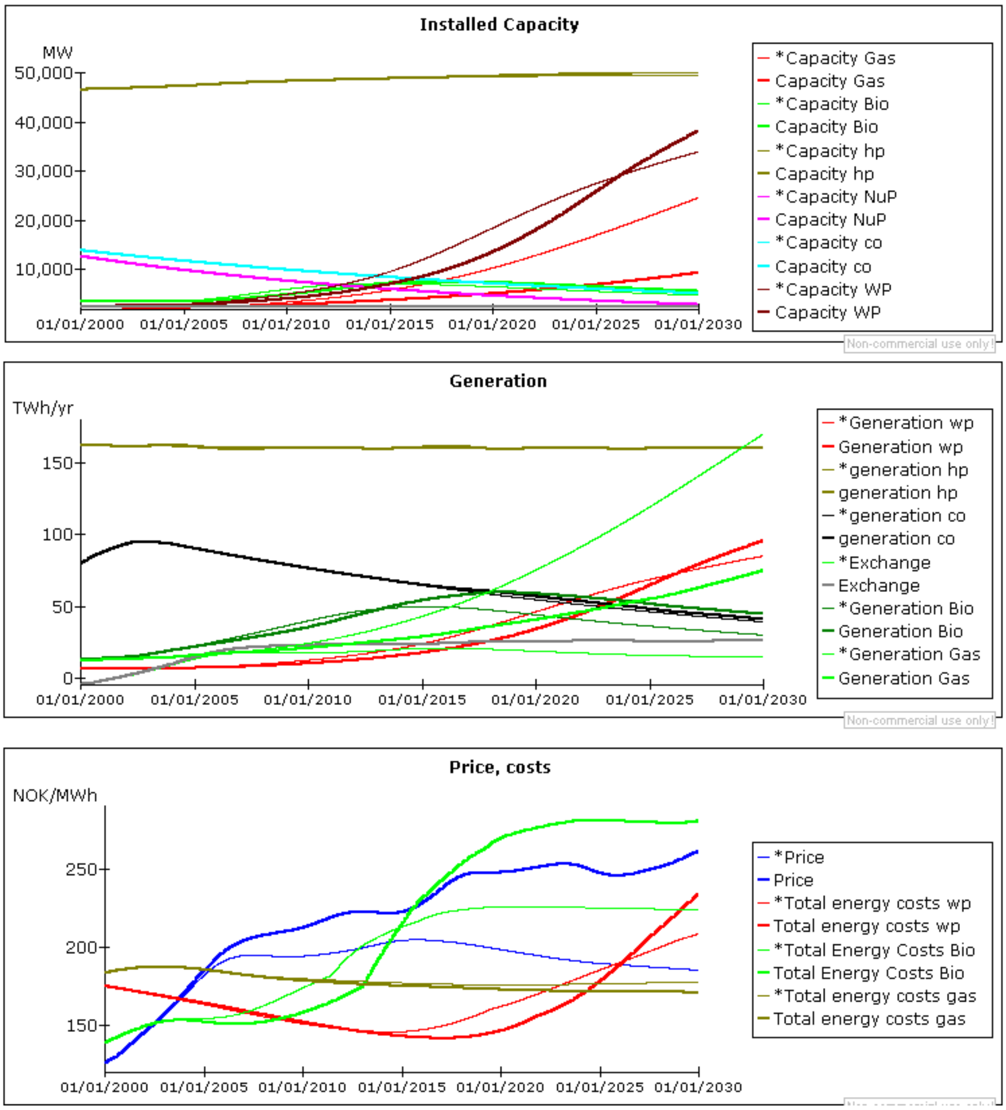


Figure 28The effect of a stricter application procedure. Applications rejected: 30% for all technologies except biomass (no reject). Application processing time increase by 1 year for biomass and wind, and 2 years for hydropower and gas.

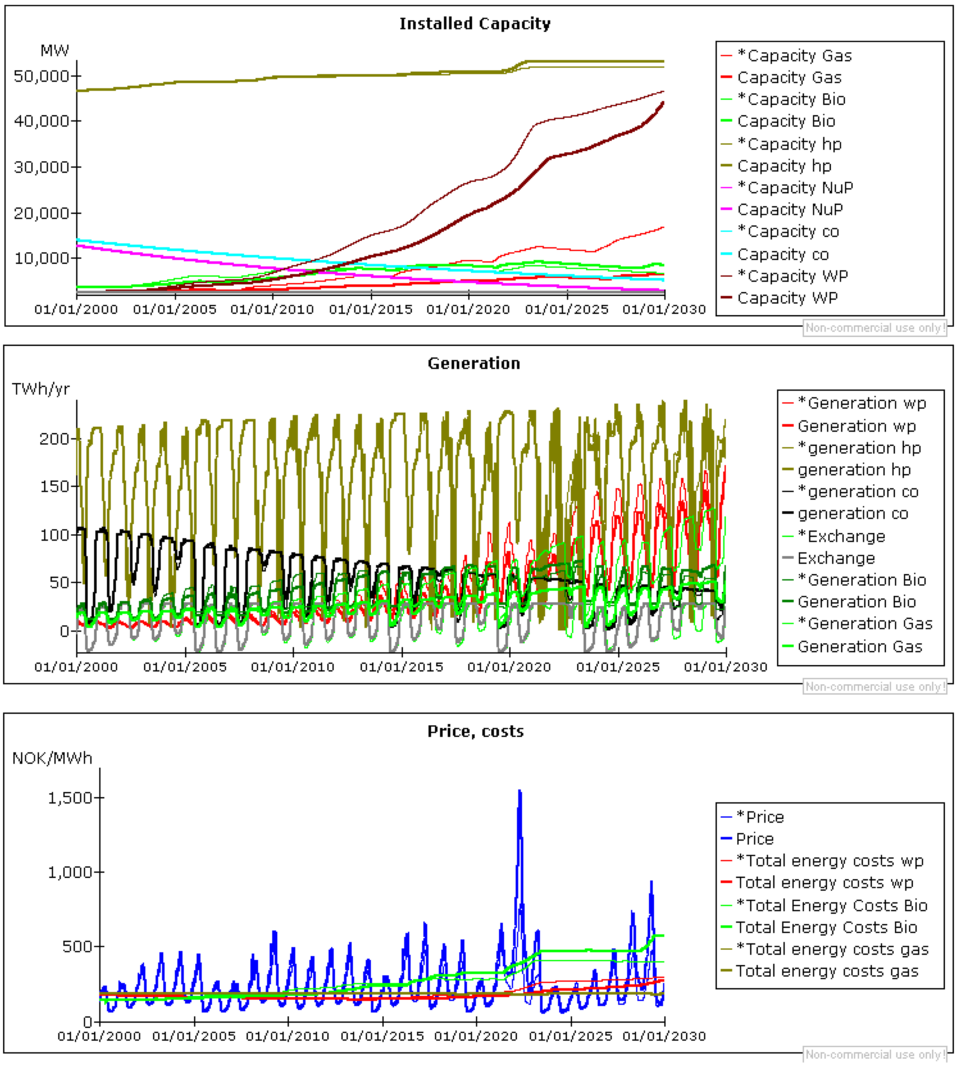


Figure 29 The effect of a stricter application process. Seasonal variations included (thick line) Thin line: no seasonal variation.

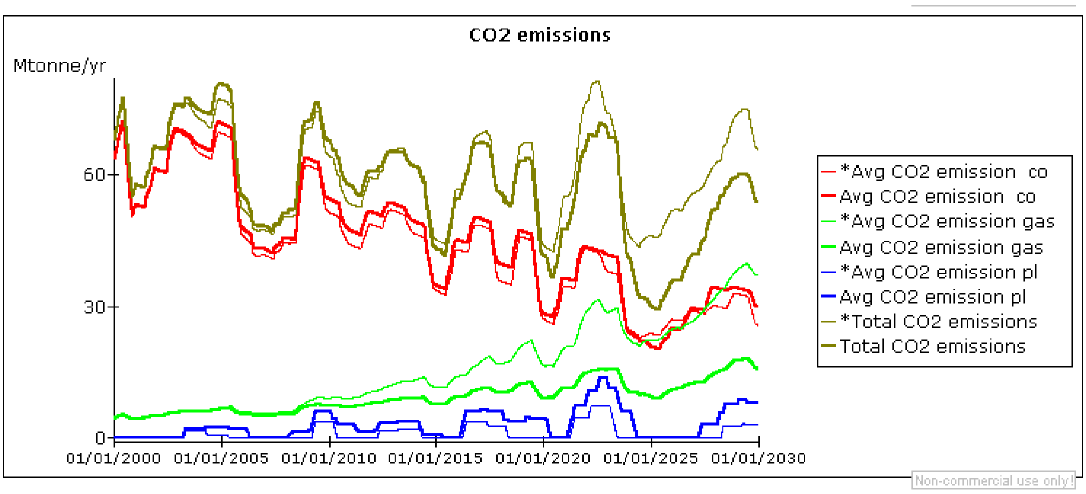


Figure 30 CO2 emissions as a result of stricter application process: A minor change in emission levels. Coal power is not affected by this strategy.

Conclusion

The few policies evaluated showed to have some long-term impact. We have only compared a few possible policies, and a combination of various policies could prove to be more efficient. Some new market-based policy instruments will be implemented and tested. These are the CO2-quota markets, and the Tradable green certificate system. Both instruments are supposed to replace direct tax/subsidy interventions, and such a simulation model can simulate possible problems in the design of these.

There is a need to evaluate these policies against each other in terms of efficiency, for instance discounting subsidies or the socio-economic surplus for each policy and scenario to net present value as a measure of total costs. Further research will be carried out in this direction.

Introducing new markets increase the possibilities of strategic behaviour, that can be studied through through this system dynamic model.

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Appendix

The model is available as a powersim file at http://www.stud.ntnu.no/~klausv/systemdynamics/

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