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A system dynamics analysis of the Nordic electricity market: The transition from fossil fuelled toward a renewable supply within a liberalised electricity market

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Acknowledgements

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Part I

The Nordic electricity market

This part starts by outlining the scope of the thesis in *Chapter 1* in terms its purpose, scientific contribution and the results achieved. An introduction to system dynamics is presented in *Chapter 4*, for the benefit of engineers unfamiliar with the modelling technique in the school of Forrester. *Chapter 2* describes the background and history for the Nordic electricity market and its organisation. *Chapter 3* gives a brief overview of decision support models for long term scheduling, price prognosis and energy policy studies in a Norwegian context. *Chapter 5* introduces a simplified model of the Nordic electricity market, which provides an overview and allows for sensitivity analysis of the important aspects of the model to be conducted before introducing the detailed model.

1   Introduction

Major changes are taking place in the electricity sector, such as the liberalisation of electricity markets and the transition towards a renewable electricity supply. Nord Pool, established in 1993, was the first trans-national electricity market. The Nordic countries are also at the forefront in developing renewable generation technologies. Our favourable resources of hydro, wind and biomass makes it possible to base the entire future electricity supply on renewables.

In the regulated regime, utilities could make detailed, long-term plans in collaboration with regulators and authorities. Authorities used taxes, subsidies or direct intervention as instruments for energy policymaking. The purpose of utilities was to provide electricity at minimum costs, for which extremely detailed optimisation models were developed for short-term and long-term planning. As vertically integrated monopolists, the income from consumers was reliable.

In the new regime, authorities have delegated much of their control to the market. National taxes are no longer efficient in trans-national markets, and direct intervention will distort the market. The authorities responsibility has shifted from direct planning of the electricity supply to the design and regulation of markets. In the liberalised market, consumers can freely choose their suppliers. Market conditions for utilities are highly uncertain and will increasingly depend on customers' preferences and the action of competitors, which complicates long-term planning.

Detailed energy models for long-term planning are less relevant in a liberalised electricity market where decisions are decentralised and the outcome of your decisions will not only depend on one persons actions, but the actions of others as well. In this new environment, utilities move from planning to strategy, where strategic analysis, scenarios and risk management, are the appropriate tools.

Still, we must deal with *environmental goals*, *security of supply* and *economic efficiency* within the context of the liberalised, transnational market. New instruments are in the early stages development. Tradable emission permits of CO_2 and tradable green certificates are examples of market-oriented instruments that can be used to achieve environmental goals. Markets for capacity and capacity subscription can be a market-based means of securing supply.

Most of the existing decision support models are partial equilibrium models that assume perfect market conditions. Consequently, these models cannot be used to analyse the performance of market designs, i.e., how or whether markets will converge towards equilibrium, due to trading strategies and time and information delays.

The focus in thesis is on the development of new simulation tools that can 1) assist authorities and regulators in designing efficient markets according to their goals and 2) help utilities develop consistent scenarios for strategic analysis. The proposed models provide experimental laboratories for authorities, companies and researchers to address long-term versus short-term implications of energy and environmental policies.

1.1   Thesis outline

The thesis is organised into four parts :

Part I - The Nordic power market introduces the Nordic power market (chapter 2), and the decision support models presently in use (chapter 3).

Part II - Kraftsim a system dynamics model gives a brief overview of system dynamics theory (chapter 4), and its particular modeling features and philosophy aimed at readers not

familiar with system dynamics. In chapter 5, we introduce a simplified system dynamics model of the Nordic power market to generate some insights, and to conduct structural and parametric sensitivity analyses. Chapter 6 then introduces the main work in this thesis: *Kraftsim*, a system dynamics model of the Nordic power market. Chapter 7 - 14, presents each sector of the model and its assumptions.

Part III - The transition from fossil fuelled towards a renewable supply within a liberalised power market shows two important applications of the Kraftsim model and the modeling concept. Chapter 15 analyses the CO2-controversy, a controversy that has dominated the Norwegian energy discourse in more than one decade. Chapter 16 analyses the Tradable Green Certificates market with the use of experimental computer laboratories.

Part IV - Utilising the complementary characteristics of renewables provides an analysis of the benefits of including wind power in hydro scheduling, in a deregulated market (chapter 17-18). This is demonstrated through the development of a stochastic dynamic model representing simplified EOPS[1] and EMPS[2] models.

Part V - Conclusions Chapter 19 gives a summary of conclusions and chapter 20 makes recommendations for further work.

1.2   Limitations of the work

The work focuses on the short- and long-term mechanisms that will influence the development of generation technologies. Although interesting developments take place on the demand side, the focus of this thesis is on the supply side. We represent through a simple yearly growth, seasonal and/or daily load patterns and price elasticities.

The model is organised around the competition between *technologies.* Competition between companies, merging and acquisition are assumed to not influence the choice between technologies. The model represents the Nordic area as a whole, and there is no representation of the transmission system within the Nordic countries, assuming that transmissionconstraints will not significantly influence the issues of concern in this study. If we were to analyse issues in the short-term, transmission constraints would be increasingly more important to the results.

While uncertainties are addressed through Monte Carlo simulations, uncertainties are not taken into account in the decision rules embedded in the model except for hydro scheduling. Furthermore, the model is a descriptive simulation model for simulation and does thus not prescribe an optimal solution.

1.3   Main contributions in this thesis

The main contributions of this thesis are 1) the development of a system dynamic simulation model on a fully liberalised Nordic electricity market, 2) analysis of two important energy policies using the Kraftsim model, 3) development of a model to study the stochastic complementarities of wind power in hydro scheduling and 4) analyses of the benefits of including wind power in hydro scheduling. A stochastic representation of wind power based on 30 years of meterorological data was also implemented in the EMPS model and has been used for several case studies. The Kraftsim model informs decision-makers, utilities and regulators of the consequences of the proposed TGC market design.

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1. EOPS - Efi's one-area Power Market Simulator
2. EMPS - Efi's Multi-area Power Market Simulator

A system dynamics model of the Nordic power market: Previous SD models of the electricity sector can be classified into 1) detailed system dynamics models of the regulated electricity industry, 2) models that study the interaction between energy and other sectors and 3) SD models that address specific problems (i.e. business cycles or strategic bidding) of deregulation. Kraftsim represents a broad range of feedback mechanisms centered on the competition between technologies in the liberalised electricity market. A new model for investments driven by expectations is proposed, where expected prices as well as price distributions are endogenous. Endogenous representation of water values in models with investments allows us to studi how the water value based hydro scheduling strategy changes in response to capacity additions. *Kraftsim* includes a *green certificate market model* with *trading strategies.*

Analyses with the model : Using the Kraftsim modeling concept, the following CO2 controversy question was addressed : *"Will building gas power in the Nordic electricity market increase or reduce CO2-emissions?"* The analysis yields new insights on the short-term versus long-term implications of the environmental impacts of building new gas power and compared with other decision support models. The total impact of building gas power is an increase of CO2 emissions in the long run.

The Swedish market design (as of May 2003) was also analysed with the Tradable Green Certificate model. It was shown that due to market design, TGC prices was likely to settle on the price cap shortly after introduction. Moreover, the market was likely to stimulate to overinvestments, leading to a subsequent price crash. The underlying cause of this behaviour was identified and corrections to the design were proposed based on simulations and laboratory experiments. Conversely, the analysis was also used to propose trading strategies for market participants and provide recommendations on investments.

These two case studies illustrate the use of the Kraftsim modeling concept, whereby the first case illustrates the importance of addressing both long-term and short-term effects in energy policymaking, while the second case illustrates why dynamic, disequilibrium models in combination with experimental economics are needed to assist authorities in market design.

An SDP[1] model of hydro scheduling with wind power : The complementary characteristics of wind and hydro can be utilised in hydro scheduling including the stochastic properties of wind in hydro scheduling tools. Stochastic description of wind power was included and simulated in the EMPS model for various scenarios for the first time. Furthermore, a stochastic dynamic optimisation model was developed to study the potential benefits of including wind as a part of the hydro scheduling problem. One version of the model resembles the EOPS model, where prices are given as exogenous input scenarios. This model represents the case of production scheduling for the single utility. The other model represents the EMPS model with endogenous prices. This model is used to analyse the impact of including wind in hydro scheduling for the total Nordic power market.

The following hypothesis was proposed and tested: *"The complementary characteristics of wind and hydro in terms of seasonal variation will reduce the need for reservoirs and thus reduce potential spillage if wind is included in the hydro scheduling problem, and therefore increase the total value of generation than if performed as separate tasks"* With the above mentioned SDP model, this hypothesis was tested under varying conditions of access to market, regularity of reservoirs and share of wind in the system. The results show that wind pow-

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1. SDP - stochastic dynamic programming

er when included in hydro scheduling will increase the value of the generation through changes in optimal reservoir management, which in turn will lead to a reduction of spillage. To utilise these complementarities in a liberalised market, the complementary characteristics of wind power must be described in the EMPS model used to generate price prognoses that are fed into local EOPS models. In that case, the local utility can perform hydro scheduling without wind including wind, unless they possess wind and their market access is relatively limited. In case of the latter, their local wind generation should be included in their hydro scheduling problem.

Electricity market laboratories: It was demonstrated how the TGC model could be converted into interactive computer network laboratories to analyse trading strategies. All of the above mentioned model developments could be converted into experimental laboratories where players make some of the decisions (i.e., investments, TGC bidding, or production scheduling) interactively. These models have potential applications for teaching/ training, market testing and design, and experimental research.

2 Organisation of the electricity market

Historically, the large variation of hydro inflow both seasonally and geographically in Norway made interconnection of separate production regions attractive at an early stage. *The Association for the Integrated Operation of South-Eastern Norway* was formed in 1932 with the intention of coordinating hydropower generation among utilities. Similar organisations all over Norway started to form, eventually becoming the National Pool in 1971. The Nord Pool marketplace, where the electricity supply of the Nordic countries are now coordinated, was established in 1996

The rationale for liberalising the regulated electricity sector, was to improve economic efficiency. There were several indications of inefficiency, as pointed out by economists throughout the 70's (Johnsen, 1998). Low return on capital, large price differences between regions and customers, and wholesale prices well below long term marginal costs indicated lack of competition and over-investments.

The Energy Act of 1991 introduced by the Norwegian Parliament gave consumers the right to choose their supplier of electricity. Moreover, transmission and generation were made into separate economic entities. The provision of electricity then became subject to competition, while transmission and distribution were organised into a regulated monopoly, providing access to generators and consumers.

2.1 Electricity supply

The Nord Pool area is a hydrothermal system with a yearly average generation of 390 TWh/yr. Hydro is the single greatest contributor to the system with 200 TWh/yr. Nuclear, coal and gas contribute 100, 60 and 10 TWh/yr, respectively. Non-hydro renewables generation totals 21 TWh/yr, 15 of which comes from bio and 6 TWh of which comes from wind.

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 an important role in industrialising the Nordic countries. In Denmark, wind energy was revived during the energy crisis of the 70's, and it is now the 3rd largest export industry. Hydropower in Norway gave rise to the country's energy intensive industry, for instance Hydro and Elkem. 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 to phasing out fossil fuels in order to convert to a renewable based energy supply by 2050 (Energy 21). Sweden formulated similar targets for a long-term sustainable energy supply (NUTEK, 1997).

The present state of the Nordic power supply is summarised in *Table 2.1*. Scenarios for 2010 are based on several reports and (in addition to the above mentioned) according to energy policy goals of each Nordic country. See Vogstad et al. (2000, 2001) for references underlying *Table 2.1* and Appendix B for details).

Supply	NOR		SWE		DEN		FIN		Total	
	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

Table 2.1 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)

2.2   Organisation of the Nord Pool market

The Energy Act mandated separation of transmission and generation (at least in accounting), and customers were free to choose their suppliers of electricity. The market is organised into several institutions that are assigned roles and responsibilities as illustrated in *Figure 2.2*. These will be explained in the following sections. For a survey on experiences with the Nord Pool market, see Flatabø et al. (2003).

Figure 2.1 Organisation of the Nord Pool Market
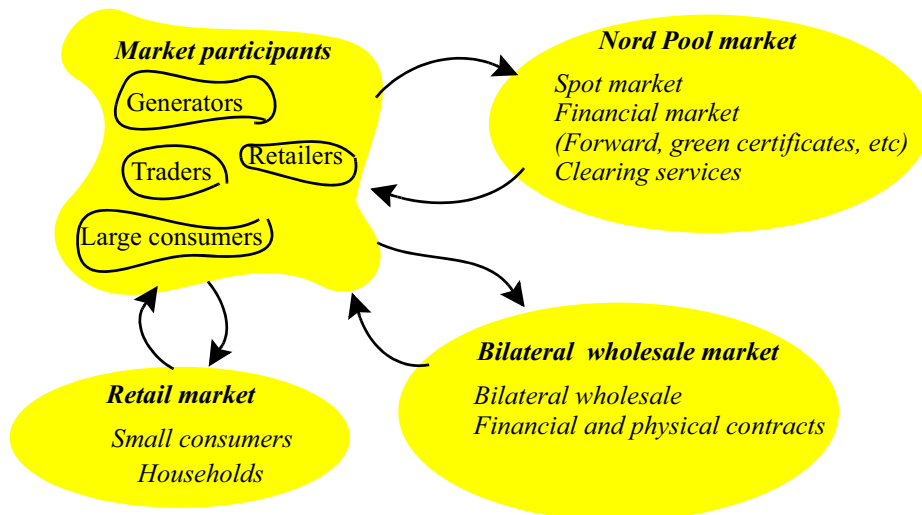
2.2.1   Grid owners

Grid owners operate monopolies according to the by-laws and regulations of the regulators. **Distributors** operate distribution- and the regional grid. Their responsibilities are to measure and charge customers for transmission, set transmission tariffs, and to maintain the grid. The main grid is operated by the TSO (Transmission System Operator) in each country. Their role is to secure supply and quality, manage real time system operations and handle imbalances in close collaboration with market participants and the Nord Pool market.

2.2.2   Market participants

Generators operate both in the wholesale market and the retail market. They also trade services from the Nord Pool spot and financial markets, for risk management, balancing power and green certificates. **Traders** are legal entities that operate in the markets, and both generators and large consumers and retailers act as traders. Small customers usually buy electricity through **retailers** that can be either traders or generators.

2.2.3   Markets

The Nord Pool Exchange convey essential market information to market participants. The most important information is the spot price, which serves as a price reference for the derivatives markets. Clearing services and standardised contracts are provided, and the information of contracts are published and reported as well. Several derivatives are provided in the Nord Pool market. Future and forward contracts can be traded from one week up to four years ahead. These are grouped into weekly, monthly, seasonal and yearly blocks. Area pricing to manage congestion, and balance markets to handle imbalances, are services provided in close collaboration with the TSOs. Additionally, contract for differences are used to hedge risk from congestion. These markets are not a focus of our model, which does not in-

clude any representation of the grid. We will however, look into the spot market, the forward/ futures market and the green certificate market in more details.

2.2.4   Spot market

Price-quantity bid/offer curves for the next day can be submitted until Noon each day. Nord Pool calculates the spot price by the market cross and then publishes prices and obligations within 1.5-2 hours. A report to the real-time market is also being made. Due to the time delay between bids and physical delivery, deviations between original bids/offers and physical generation/consumption must necessarily occur. The spot market is shown as the loops *B2* in *Figure 2.2* below. Prior to the bidding in the spot market, calculations of profitability are made based on information about costs, perceptions about future prices, reservoir levels, etc.

2.2.5   Real-time market

The real-time market (shown as the loops *B1* in *Figure 2.2*) is used to handle the above mentioned deviations that occur during the time between submission of bids and physical delivery in the spot market.

2.2.6   Futures market

The futures market is used to manage risk, and provides a joint expectation of future prices, plus a risk premium. Depending the time horison, the futures market may incorporate information on reservoir fillings, expectations about future events (such as the commission of a new transmission line or new capacity), or other factors that may influence the electricity price in the long-run. This is depicted by the loops *B3* in *Figure 2.2*. No physical transaction of electricity takes place as a result of trades in the futures market. As can be seen from *Figure 2.2*, price expectations are adjusted, which in turn influence the spot market. Additionally, the futures market can be used as an indicator for long-term prices, and therefore, investment decisions.

2.2.7   Elcertificate market / TGC market

The elcertificate market was newly introduced in March 2004 on the Nord Pool Exchange. In March, 2003, a tradable green certificate (TGC) market was established in Sweden as a bilateral market. Subsidies for renewables were then replaced by TGCs that can be freely traded as financial assets. TGCs represent the additional cost (or value) of renewable generation needed to satisfy pre-specified targets. For each MWh of electricity generated from certified renewable sources such as wind, small scale hydro or bioenergy, a certificate is issued. End-users are obliged to meet an increasing share of their demand from renewables.

Each year, a Redemption Body controls whether targets are met and issue penalties, if needed. The TGC market is discussed further in *Chapter 16*.

Figure 2.2 Causal loop diagram illustration of the various feedback processes in the Nord Pool market, including *Real-time, Spot and Futures* market.
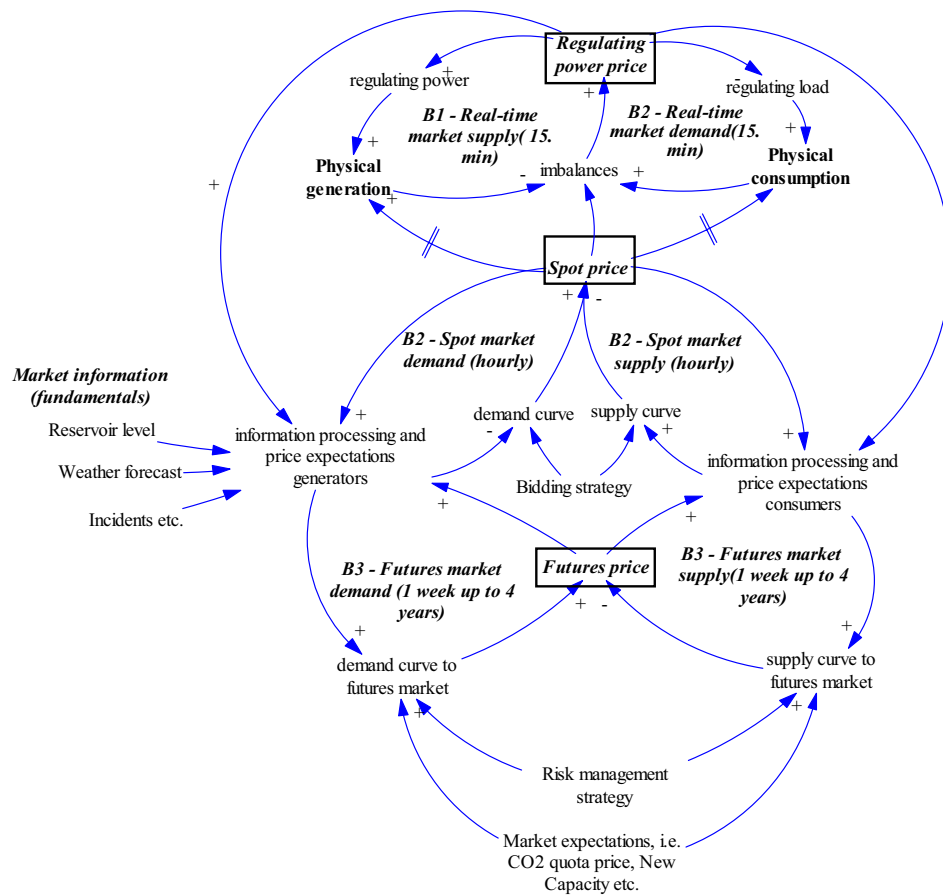
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3 Decision support models in the Nordic electricity market

Specialised decision support models have been developed to assist utilities, regulators and authorities for planning and energy policy analysis. Some of the models have undergone changes in accordance with the challenges faced by utilities in the liberalised market. The EMPS model was applied in Part III of this thesis. The new system dynamic model reported in Part IV, is meant to complement existing decision support tools. Throughout the thesis, comparisons with the existing tools are made to point out differences in modeling concepts and their implications for policymaking. This chapter gives an overview of existing decision support tools within a Norwegian context and presents an overview of previous work on system dynamics models in the electricity sector. The chapter ends with a discussion on different modeling paradigms.

3.1 The EOPS and EMPS model

EOPS (Efi's One-area Power Simulator) is a decision support tool for seasonal hydro scheduling. The model is a technical bottom-up model with a detailed representation of the hydraulic system of reservoirs and generating units. Its main use is to compute water values for input to short-term scheduling models. Thermal units with marginal costs and price sensitive consumer loads are also described, while access to other areas are represented through capacity constraints.

The electricity market is represented by a price model as described by Mo et al. 2001, which takes price scenarios from the EMPS model as input . The stochastic representation of hydro inflow utilises 60-70 years of historical inflow data. The model optimises hydro generation over a year using stochastic dynamic programming and the water value method.

EMPS (EFI's Multi-area Power-Market Simulator) was originally developed for hydro scheduling purposes but has been further developed for price prognoses (Fosso et al. 1999). The EMPS model consists of several interconnected one-area EOPS models that comprise the

total Nord Pool area. In addition to price prognoses, the model is being used for market analysis and energy policy studies.

Figure 3.1 The EMPS model consists of several interconnected local areas with various supply technologies, demand and market access. (Source: Vogstad et al., 2001; Vogstad, 2000)
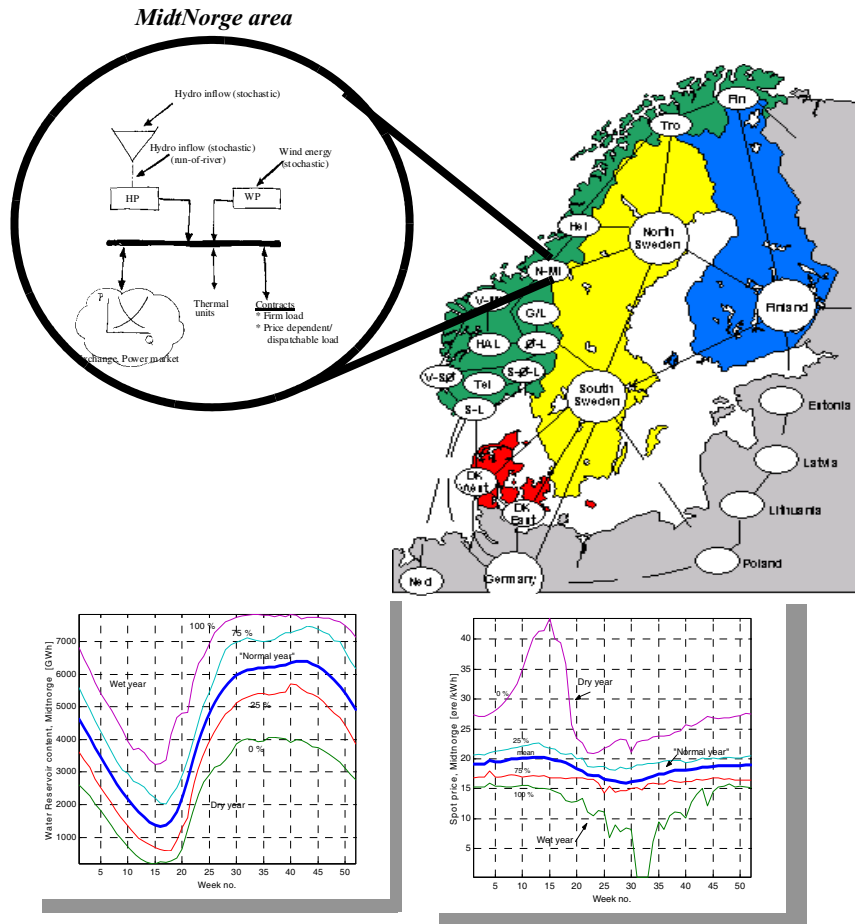
The EOPS and EMPS models are both products of Sintef Energy Research. SAMLAST (Hornnes, 1986) is a further development that includes a DC load flow model on top of the EMPS model. A similar extension to the EOPS model, called SIMTAPEFFEKT is under development (Warland and Belsnes, 2000; Vogstad et al., 2001). Other improvements are integrated risk management with contract and hydro scheduling (Mo et al., 1999),

The main features and exogenous versus endogenous variables are displayed in *Table 3.1*. Electricity price and generation scheduling endogenous, while long-term mechanisms such as capacity acquisition, technology progress and resource availability, do not need to be represented for shorter time horizons of one to three years. The EMPS model has been used to analyse the impact of building new gas power plants on Nordic CO_2 emissions, (Wangens-

teen et al., 1999), the profitability of new transmission lines, and the integration of wind power (Vogstad 2000; Vogstad et al., 2000, 2001).

3.2   NORDMOD-T

Statistics Norway has a portifolio of macroeconomic models applied to various sectors to assist the Government in planning. One example is the NordMod-T model (Johnsen, 1998), which has been used for long-term analysis of the Nordic electricity market. It is a technical, bottom-up, partial equilibrium model representing the Nord Pool market with five interconnected areas. The model is implemented in GAMS and optimise the socio-economic surplus by a nonlinear solver. Representation of hydro scheduling is less detailed than the EMPS model, but consumption, tariff/tax structure and thermal generation are more sophisticated. The time horizon can span up to 20 years, as generation scheduling and capacity acquisition are endogenously represented.

The model has recently been used to analyse the impact of building gas power on CO_2 emissions in Norway (see *Chapter 18*) as well as cost-benefit analyses of new transmission lines and gas power plants (Aune, 2003).

3.3   MARKAL

Markal (Market Allocation) was originally developed at the Brookhaven National Laboratory. Over 40 countries have adopted the model for energy policy analysis and it is the most widespread energy system model in use. The model is continuously being improved through the IEA ETSAP initiative. It is a dynamic LP optimisation model that minimises costs over the time horizon. The model contains a large database of various technologies that includes the whole energy supply chain from resource to end-use. IFE[1] maintains the Norwegian version, and it has been used in NOU 1998:11, and to analyse various options for CO2-reductions. In Sweden, Markal has been used to analyse the consequences of the TGC market before introduction (SOU 77:2001).

In particular, technological progress can be included in the optimisation framework, and this feature is essential to analyse various RD&D[2], energy policies and long-term energy plans (IEA, 2000). The model is dynamic in the sense that it produces a "snapshot" of the optimal state of the system usually in five-year intervals. In *Chapter 11*, the implications of technological progress for long-term analysis is discussed more detailed.

3.4   System dynamics models

System dynamics found application in the energy sector at an early stage, and a large number of models have been developed for energy policy analyses. *Figure 3.2* shows the intellectual lineage from the introduction of system dynamics, to the energy model developments in the era before deregulation. The main environmental concern in the 70's, was the potential consequences of resource depletion and pollution whereas today, focus has shifted to global warming[3]. The famous *Limits to Growth* model of 1972 (World3) raised the question of whether energy could be a limiting constraint for the US economy. This lead to a series

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1. Institute for Energy Technology
2. Research, development and deployment
3. In fact, the Limits to Growth study did already at that time mention CO_2 emissions as a potential concern of pollution for the future.

of studies starting with Roger Naill's gas model that supported Hubbert's life cycle theory of natural gas resources (Naill, 1973; Hubbert, 1956), to the IDEAS model (Integrated Dynamic Energy Analysis Simulation) which is a dynamic long-term[1] policy simulation model of the US energy supply and demand used by the US Department of Energy. It has been used to analyse US dependency on oil imports and to shape several national energy plans, for example the cost effectiveness of US policies to mitigate global warming (Naill et al., 1991). A descendent of the IDEAS model is called *Energy 2020*, a multi-fuel model being used by states, countries and single utilities.

Previous work on system dynamics models of the electricity sector can be classified into three types: Energy-economy-environment models, models of the regulated industry and specific problems of the deregulated industry.

Energy-economy-environment models (E3 models)

Sterman (1981) recognised the lack of feedback in the existing energy models with the rest of the economy, and subsequently developed an energy-economy model to address the importance of energy-economy relationships. Continuing this thread, Fiddaman (1997) developed FREE (Feedback-Rich Energy-Economy-Climate model) that was designed so that it could also mimic the assumptions of climate-economy models such as DICE (Nordhaus, 1994).

Models of the regulated electricity industry

Another line of research known as the EPPAM models (Electricity Utility Policy and Planning Analysis Modeling) followed from Ford's dissertation (Ford, 1975). System dynamics models have a wide range of applications in the regulated electricity industry (see Ford, 1996 for a comprehensive overview). Rather than a general model, several smaller models exist to attack various problems, including particular regulatory-finance problems for utilities (Ford and Mann, 1983), hydropower and water management, and utility conservation programmes.

Problems in the deregulated electricity industry

Deregulation brought new challenges to the electricity industry, and regulators. Patterns of capacity construction in California is the topic of a series of studies, that show that boom and bust cycles similar to those in other commodity or service sectors are likely to appear within a deregulated electricity industry (Ford, 1999, 2001). In the UK and Latin America, system dynamics models have also been used to address particular issues, such as market power (Bunn et al., 1997), market design (Bower and Bunn, 2001; Bower et al, 2001)[2], and investment behaviour (Bunn and Larsen, 1992,1994), as well as the applicability of this method to deregulated electricity markets (Ford, 1997; Bunn and Dyner 1996, Gary and Larsen, 2000; Dyner and Larsen, 2001).

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1. The time horizon of IDEAS and its predecessors is 30-40 years
2. Bower and Bunn (2001) and Bower et al. (2001) are actually agent-based models, but the agent-based model approach share many of the same underlying assumptions as system dynamic models.

Figure 3.2 Intellectual lineage of system dynamics energy modeling (Source: US DOE, 1997)
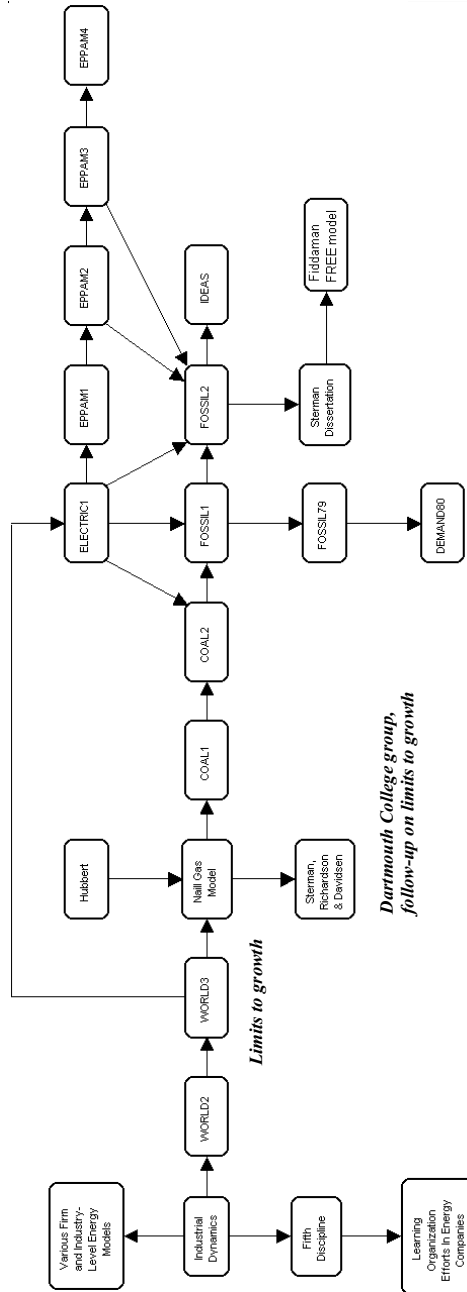
Returning to the Nordic countries, the DEMO-project in Denmark (Meyer and Rosekilde, 1980) was a system dynamics study of the development of energy consumption in households and other sectors of the economy. Norway has also applied system dynamics to energy models. Exmples of this includes the SMELT model of energy intensive industries (Nunn et al., 1979), the OILTANK model of the oil market (Ervik et al., 1980) and EUROGAS 1, a model of energy demand in Europe (Moxnes, 1986). Midttun et al. (1996) explore price formation in the Norwegian electricity market under various behavioural assumptions of utilities decisions on contract and spot market sales.

Ackere et al. (2003) shows how the system dynamics modeling process assisted strategic decision-making in the management of a hydropower plant at a chemical producer who owned a share in system of hydropower plants (Tyssefaldene). The initial problem was to increase profitability under the new market regime, but the modeling process lead to a reframing of the problem with the outcome of selling the plant rather than trying to improve its operation. The iterative process of revising the problem and underlying assumptions differs from other modelling approaches such as optimisation techniques, where the problem definition usually remains fixed (see theory chapter, section 4.3).

3.5   Kraftsim

Kraftsim is a new system dynamic model reported in this thesis that analyses the consequence of energy policies in the Nordic electricity market. The model has a time horizon of 30 years. Time resolution for our purpose is on a weekly level, although the resolution can be increased to represent chronological diurnal load patterns. There is no representation of the grid, Nord Pool is therefore as modelled one single area. This is justified by the long-term issues we currently focus on, and the fact that price differences averaged over longer time periods are small. It is also assumed that the transmissions system keeps pace with new capacity expansions and demand trends[1]. The model focus on nine technologies: *nuclear*, *coal*, *gas*, *gas with CO2-sequestration*, *peak load turbines* (gas), *hydro*, *bio*, *wind* and *wind offshore*. Demand is modeled with an underlying trend, plus long- and short-term price elasticities. Electricity markets influence, and are influenced by, *generation scheduling*, *capacity acquisition*, *technology progress* and *resource availability*, all of which are endogenous or partly endogenous mechanisms (see bullet diagram in *Table 3.1*). Investment decisions are made in a competitive market, based on a detailed profitability assessment assuming boundedly rational investors.

Table 3.1   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 - 5 year	<20 yr	<30 yr
Spatial resolution	12 areas (Nordic countries+Germany)	4 areas (Nordic countries)	One area (Nord Pool)

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1. Recent research at WSU combines load flow models with long-term system dynamic models of the Western US System to analyse the interplay between transmission and electricity generation.

Table 3.1   Overview of model characteristics

Model	EMPS	NordMod-T	Kraftsim
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

3.6   Discussion on modeling approaches

According to a survey by the Nordic Minisitry Council (2001), the following seven models are in practice used by energy authorities in the Nordic countries (country of use in paranthesis): ELEPHANT (Den), BALRMOREL (Den), NORDMOD-T (Nor), MARKAL (Nor,Swe,Fin), PoMo (Swe), EFOM (Fin), EMPS (NOR,Swe,Den,Fin) and RAMSES (Den) All of these models are partial equilibrium or technical bottom-up models using optimisation. At present, there seem to be no available system dynamics model that can assist authorities and utilities in their planning[1], and the current basis for decision making among authorities and utilities seems to be partial equilibrium models based on optimisation. A danger of using just one modelling method/paradigm, is that the problem of interest will be only partly fitted to the method. From a theoretical perspective, each method or theory rests upon several assumptions (Randers, 1973). These assumptions can be classified as follows:

• **Specification assumptions:** These assumptions can easily be altered within the applied method. They usually have to be stated explicitly, so that the readers (usually within the same paradigm) can examine the underlying assumptions of the results. The second set of assumptions are:

• **Methodological priors/meta-assumptions:** These are assumptions on which the theory or method rests. These assumptions, once the methodological approach is chosen, cannot be altered by the researcher, nor are they explicitly stated, because the researcher assumes the reader conform to the same assumptions. Conforming to neoclassical economic theory, agents behave rational, and markets are close to equilibrium. If taking the system dynamicists view, people's behaviour is boundedly rational, and decision-makers are deterministically entrenched in the information feedback system in which they operate.

The choice of method will influence the specification of the problem in the sense that the problem definition partly must be partly fitted to the method. Depending on each method's methodological priors, the relative importance of specification assumptions will also differ. *This places a responsibility upon the analyst to continually examine his selection of method as well as his specification and execution of a study within a given technique* (Andersen, 1980).

The limitations of traditional energy modelling approaches (i.e. optimisation), as identified by Bunn and Dyner (1996) are that they are inherently *normative (prescriptive),linear, lack important feedbacks* whilst being *mechanistic and non-behavioural.* Dyner and Larsen (2000) show how the fundamental assumptions underlying modelling methods under monopoly have changed from planning to strategy in a liberalised market, requiring complementary

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   1.   System dynamics models are being used by some utilities, either developed by consultants or staff for traning or strategic analysis, but these models are not reported or publicly available.

modeling approaches such as *agent based models*, *system dynamics*, *real options, game theory* and *financial risk modeling* in addition to the traditional ones.

Lessons from previous experience also point out the usefulness of system dynamics as a modeling approach within the utility industry (Ford, 1996). Of particular interest, is the Utility Modeling Forum (EPRI 1981; Ford and Mann 1983), a group of experienced members from utilities that gathered to systematically run and compare decision support models. In their model comparison, the system dynamic model produced results that were significantly different from the others in their runs. The model was far less detailed, had fewer equations, and cost less to develop than the other models. These features might have initially dismissed the model, but as the testing progressed, its unique feedback characteristics revealed parts of reality that that were lacking in the other models, thus giving rise to differences in results.

Kraftsim differs from the partial equilibrium models by being descriptive, rather than prescriptive. Long-run equilibrium is potentially a result of the policies and model structure, not an assumption underlying the model. Behavioural assumptions of investments are boundedly rational, and the large delays involved in acquisition of new capacity as well as the expectation formation in markets are explicitly represented. Technological progress and resource availability are endogenous, not exogenously determined, which is of importance for evaluating the stimulation of new technologies. Kraftsim's underlying assumptions will be contrasted with those of the EMPS, NordMod-T and Markal in the subsequent chapters describing the model sectors.

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4   System Dynamic theory

This chapter is an introduction for readers unfamiliar with system dynamics. Readers already familiar with the field may skip this chapter.

4.1   History of system dynamics

Jay W. Forrester is the founder of System Dynamics. After his B.S degree in electrical engineering in 1939, Forrester worked under Gordon S. Brown - the pioneer of feedback control systems (servomechanism) at the MIT laboratory. After World War II, Forrester lead a project of building a real time flight simulator which could predict the behaviour of air planes from wind tunnel test data prior to construction. This project culminated in the design of the Whirlwind digital computer (Forrester, 1989). By that time Forrester had pioneered the field of feedback control systems as well as digital computers, for which he holds a number of honours and patents.

In 1956, he joined Sloan School of Management at MIT, which was an experiment of to create a management school within an engineering environment. Operations research was at that time already an established field contributing to management from a technical perspective. However, Forrester was looking for a more practical approach. Based on a study of fluctuating production cycles in a GE household appliance manufacturing plant, he developed a method that is now known as system dynamics.

In 1961 Industrial Dynamics was released. The book presented the method of studying information-feedback characteristics of industrial activity to show how the flows of money, orders, materials, personnel and capital equipment are interrelated through information flows and policies that in turn control these flows. As a further step, *Urban Dynamics* brought system dynamics to more broader social systems. The study showed how the adopted policy of building low-cost houses was actually detrimental to reviving inner cities in the US. In 1970, the World Dynamics study and the later *Limits to Growth (*Meadows et al., 1972) report to the Club of Rome dealt with future problems of sustainability of mankind. It appeared that the system dynamics method was a general and practically applicable method to analyse complex problems.

During the last 30 years, system dynamics has continued to grow and found several applications in many fields of science. The field has its own scientific society, with yearly conferences and journal, the *System Dynamics Review*. Many universities around the world now offer courses and Master programmes in system dynamics. Experiments of introducing system dynamics to junior high school student have been very successful (Forrester, 1996)

4.2   The system dynamics paradigm

Forresters concern was that current management science emphasized single decisions, neglecting the fact that decisions are distributed along chains where one decision point influ-

ences the subsequent decision points in such a way that the decisions are altered. *A feedback*

Figure 4.1 Information feedback systems: decision-making in a (a) linear world, (b) nonlinear world and (c) nonlinear world with multiple feebacks.

(a)   (b)   (c)
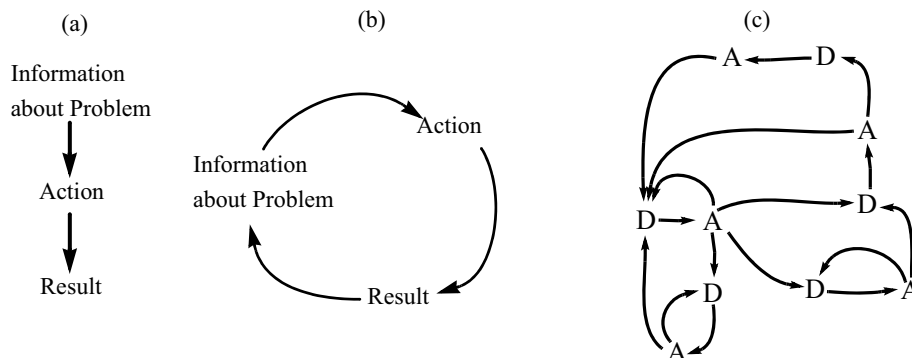
structure is a setting where existing conditions lead to decisions that cause changes in the surrounding conditions that influence later decisions. That is the setting in which all our actions take place. (Forrester, 1991 p8).

Figure 4.1a) shows a typical linear world view within which most discussions take place in media, business and politics. Based on information about the problem, decisions are made in order to correct the problem to achieve the desired result. *Figure 4.1b)* shows a nonlinear world view, which consider problem solving as a continuous process where results reveal new information about the problem upon which decision and action are taken, which again changes the condition of the system. *Figure 4.1c)* shows an even more realistic multiple-loop information feedback structure of multiple decision-makers (D) that take actions (A), which influence the decisions of others.

Figure 4.2 represent the same information feedback structures as those of *Figure 4.1* but in terms of dynamic stocks and flows processes (the stock and flow diagrams will be explained in more detail in section 4.5). In *Figure 4.2a)*, the observed system state is compared to the desired system state at the decision point and converted into actions according to a decision policy, thereby controlling the flow that changes the system state. The close-up of *Figure 4.2a)* shows the general structure of a decision. The observed system state is compared to the desired system state, and corrective action takes place to adjust the "valve" of the flow that control the system state. *Figure 4.2b)* shows the multiple loop information feedback structure of alternating stocks in which decision-makers control the "valves" of the flows.

Any one who has had some experience with nonlinear feedback systems, knows that the resulting behaviour of a change in such a system is extremely difficult to anticipate by sheer intuition. It is the equivalent of solving higher-order differential equations. Still, it is in this context that decisions are made in organisations, in energy policymaking, and in everyday life. This is where system dynamics can play an important role to design policies that can improve undesirable behaviour that arise from poorly managed complex systems.

A system dynamic model can be generalised into the following structure :

Closed boundary
  Information feedback structure
   Levels and rates
    Goal, observation, discrepancy, action

Decision-makers convert information controlling the rates of the system at the decision points (*Figure 4.2b)*, which changes the levels (system state) from which new information is made available to the decision-makers. decision-makers behave as *boundedly rational agents (see* section 4.2.1*)*. Decision-makers are information converters that make decisions according to their policy based on information available to them. Decisions control the rates in a system, for example monetary flows of investment, capital equipment, hiring of labour etc.

Figure 4.2 Dynamic information feedback structures

a) The components of a dynamic information feedback system
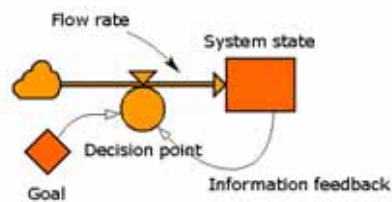
b) Multiloop dynamic information feedback system
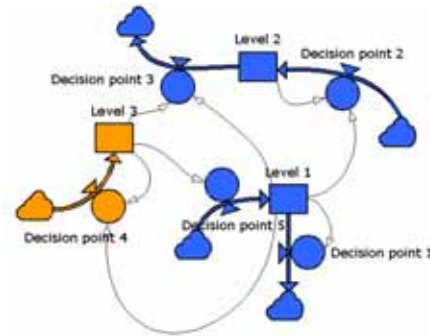
4.2.1   Decision-makers as boundedly rational agents

Most economic equilibrium models assume rationality of decision-makers. This assumption is rather ambitious. It implies that decision-makers are capable of having complete knowledge of relevant information, perfect anticipation of future consequences, and the cognitive capacity and time available in order to do so. In reality, none of these assumptions are sufficiently met (Sterman, 2000 p599).

A more reasonable description of decision-making is the concept of *bounded rationality*. According to Simon (1957), "*[t]he capacity of the human mind for formulating and solving complex problems is very small compared with the size of the problem whose solution is required for objectively rational behaviour in the real world or even for a reasonable approximation to such objective rationality.*" When decisions are made, our cognitive capabilities restrain us to assemble a few relationships out of the large amount of information available. At best the decisions are reasonable; at worst systematic misperceptions in decision-making lead to counterproductive outcomes of decision-making. Such behaviour has frequently been reported in system dynamics literature (Forrester 1968; Sterman 2000 and Moxnes,1998), in economics (Smith et al., 1988), and in cognitive psychology (Hogarth, 1987 ch3), where human decision-making has been the subject of study. Cognitive limitations also apply to the researcher itself, which is why simulation models are needed to correct the often unreliable intuition of mental models.

This being said, decision-making can still be considered as rational, but within the bounds of the limited simplified mental models[1] under which the decisions are carried out. System dynamics models focus on capturing the essential information and guiding rules from which policies are routinely made, adapted from theories of cognitive psychology such as anchor and adjust, Brunswik's lens model of information cues, adaptive expectations and so forth.

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1. A set of assumptions is in system dynamics often denoted mental models

See Sterman (2000, ch14-15) and Hogarth (1987, ch5) for an extensive treatment of modeling bounded rationality.

4.2.2 Policies and policy design

In the system dynamic context, a *policy* is defined as *the set of rules by which available information is converted into decisions according to goals*. The policy of an inventory manager is to adjust the actual level of inventory to the desired level. The policy of an investor is to select the most (expected) profitable project.

One may argue that the decisiondecision-makingmaking process is a complex matter intrinsically difficult to describe. That might be true at the individual level. But if one takes a step back and views the decision making process as a continuous stream of decisions, it is possible to capture the essentials of a policy to sufficiently reproduce the system behaviour that arises from the multiple flows of decisions (Forrester, 1961 pp93-107). Stepping too far back, for instance by assuming perfect market conditions of a sector one may overlook the underlying cause of the problem (for example, market power leading to high prices).

The challenge is to capture the relevant causal relationships that generate the problem of interest without rendering the model too complex. Selecting the important relationships from the less important ones can only be done by trial and error, due to our cognitive incapabilities of dealing with complex nonlinear systems. Defining the adequate system boundaries of a model is therefore an iterative process. As we understand more about the problem, we are able to identify important relationships from the less important ones.

4.2.3 Sources of information

To build models using the system dynamics approach one must rely on all available sources on information. Forrester distinguishes between three sources of information :

The mental database is by far the richest source of information. Employees, experts and workers of a company or organisation (i.e. decision-makers), provide the knowledge that enables us to reconstruct the policies that are governing decisions that influence our problem. It may be public authorities in charge of permits, or it may be production planners of a utility company. Their practice may not conform to the prescriptions expressed in textbooks. For instance, managers may use missing backlog of orders as an indicator of new capacity requirements rather than projected demand. Production schedulers in power markets might adopt some exploratory bid strategies rather than bidding according to operational costs. Information from the mental database can be extracted from discussions and interviewees and from business magazines, newspapers and the media.

The textual database draws upon long-term experience synthesized into general theories expressed in journal papers and textbooks. The generality of the theories may not conform to the particular problem of interest, but are on the other hand more generally applicable. This source of information contains less information than the mental database, because theoretical descriptions have to be simplifications of reality. Imagine a company to be run by implementing the procedures and theories explicitly stated in textbooks. Such an experiment would simply be impossible because such information cannot replace the embedded experience and routine of the operators of a system.

The numerical database contains less information than the above mentioned categories. The database contains statistics and measurements, but does not provide any information about the relationships of the data points. Despite the fact that numerical data contains the least amount of information, one may ask why modelers tend to spend most of their time on numerical data compilation. It might be a direct implication of the modeling paradigms where combinatorial (as opposed to structural) complexity and data intensity are emphasized.

4.3   System dynamics in practice.

The system dynamic approach can be summarised in the following five iterative steps illustrated in *Figure 4.3*:

1. System dynamic problems start with an initial understanding of the problem and the relevant relationships thought to be of importance to the problem. A system dynamicist should *never* model a *system*, because the problem determines which factors that are important to include and which to exclude and therefore be used to find the relevant system boundaries of the problem. A reference mode (the hypothesized behaviour of the problem) and the time horizon of interest must be identified.

2. A dynamic hypothesis is then developed in terms of a causal loop diagram and stock and flow diagrams.

3. The model is then implemented for simulation.

4. Testing of the model implies testing which variables should be endogenously modeled and which can be exogenously modeled or omitted, in order to define the adequate boundaries that endogenously replicate the behaviour of interest. Multiple feedback models are more sensitive to the structure than the parameters and the flexibility of the modeling allows for testing the sensitivity of alternative model structures. Parameter sensitivity checks are useful to decide how much effort should be dedicated to increasing the precision of the parameters.

Figure 4.3   Modeling as an iterative process
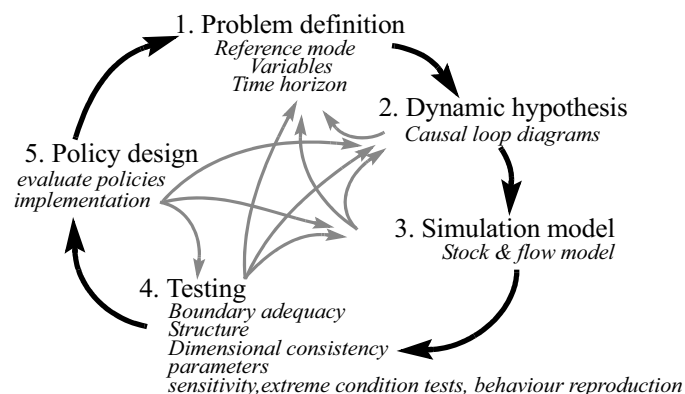
5. When reasonable confidence in the model is achieved, policy analysis and design can take place.

All of these steps may requre revision of previous steps (illustrated by gray arrows in *Figure 4.3*). That might even include revision of the initial problem definition. The system dynamics modeling process is therefore highly iterative. Typically, 80% of the time is spent on analysing the problem itself, while some 20% is spent on implementing the model (Randers, 1980). The last and most crucial task is implementing the model insight among policymakers. The success of a model analysis must be judged by the insights that were adopted by the decision-makers. Decision-makers that does not understand the model, cannot make use of insights from the model. For this reason, the focus on stakeholder involvement and group model-building with stakeholders has gained increased interest within the system dynamics community (Vennix, 1996). Often a stakeholder group or experts in a field define the problem

of interest, and the relationships involved during the course of a discussion (see the mental model column in *Figure 4.4*).

To clarify the model, a causal loop diagram can be used to get an overview of the causal relationships (middle column in *Figure 4.4*). However, the relative importance of these causal relationships and their dynamic shift in dominance over time can only be assessed by building a formal model using stock & flow diagrams, whereupon simulations can be run and analysed as a basis for further discussions and analysis (see right coulumn in *Figure 4.4*)

Figure 4.4 Model building in practice.

Mental model

Future development of Norwegian oil production. When Phillips struck oil in the North Sea in 1971 Norway started to explore the oil fields in the North Sea. Revenues from oil production were reinvested in new explorations and oil wells increasing oil production and revenues that drive our fossil fuelled economy. In this process new technologies experience and organisational skills developed improving production technology reducing the costs of production and enabled us to dig even deeper into

Causal loop diagram

Formal model

From discussion of complex problems among stakeholders and decision makers...

...To causal loop diagrams for enhanced communication and clarification ...

...and formal modelling simulation synthesis design of improvements and enhanced understanding.

New insights are again the basis for new discussions and redefinition of problems among decision-makers.

4.4   Causal loop diagrams (CLD)

Causal loop diagrams are used to get an overview over the causal relationships of a problem. With the use of CLDs, it is also possible to identify possible characteristic behaviour of the problem. They are particularly suited for communication and discussion in groups, and to build hypotheses. In this thesis, CLDs will be used to keep track of the relationships to the overall model.

The main rules of causal loop diagramming are listed in *Figure 4.5*. Arrows symbolise causal relationships between two variables. Variables must be formulated in such a way that

Figure 4.5 The four rules of Causal Loop Diagramming (CLD)

a) **Rule (i)** An *increase* in **x** results in an *increase* of **y**

b) **Rule (ii)** An *increase* in **x** results in a *decrease* of **y**

c) **Rule (iii)** An even number of negative polarities along a loop is a reinforcing loop *R*

d) **Rule (iv)** an odd number of negative polarities along a loop is a balancing loop *B*
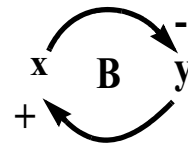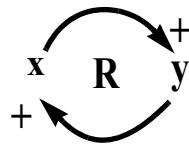
e) Reinforcing growth (*exponential growth* or *exponential decline)*
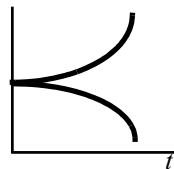
f) Goal seeking behaviour (*exponential decay* or *limiting growth*)
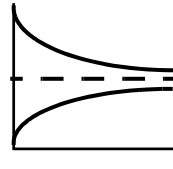
it makes sense to talk about an *increase* or *decrease* of the variable. For example, the environmental attitude cannot increase or decrease. The environmental consciousness, however, can increase or decrease. Also the causal relationship (arrow) must be unidirectional. The polarities must either be positive or negative, not both.

4.5   Stock & flow diagrams (SFD)

The world can be described as stocks and flows. To describe systems, Forrester used the bathtub analogy. Consider a bathtub with inflows and outflows as represented in *Figure 4.6*. The level of the bathtub is determined by the inflow rate and the outflow rate. The outflow

Figure 4.6 The bathtub metaphor and languages of describing dynamic problems (Adapted from Sterman, 2000)

a) **Bathtub metaphor**
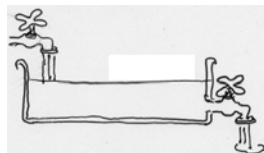
b) **Stock & flow metaphor**

inflow   Stock   outflow
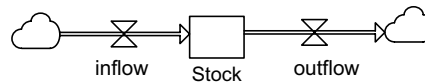
c) Integral equations

$$Stock(t) = Stock(t_0) + \int_{t_0}^{t} (Inflow(t) - Outflow(t))dt$$

d) Differential equations

$$\frac{d}{dt} Stock(t) = Inflow(t) - Outflow(t)$$

rate is again determined by the level of the water in the bathtub, since the pressure of the out-flow rises with the water level. This is the hydraulic metaphor.

Figure 4.7 shows the corresponding stock and flow diagram where the rectangles represent levels, arrows represent flows, and each flow is controlled by the valve. The clouds represent sources and sinks outside the system that are thought to be infinite or unimportant for the system of interest. For instance, we are not concerned with the availability of water in the pipe.

These four metaphors contain exactly the same information and describe the same system.

Figure 4.7 Symbols of stock & flow diagrams

a) ***Constants*** are variables that changes slowly relative to the dynamics of interest and are therefore assumed to be fixed over the simulation period.

b) ***Level*** - (also called Stock, Accumulation, Integrator or State). Levels change slowly and can only be changed through inflows and outflows. Levels are accumulations of flows, whether material, monetary, or information flows. Levels create the inertia of the system and de-couple the relationship of inflows from outflows over time.

c) ***Rate equations*** (also called inflows and outflows) control the flows that change the levels. The flows are symbolised with double arrows, often with a cloud on one end. The cloud is a system boundary, that is - we assume that the source of the flow does not constrain our problem (i.e., an infinitely large Level)

d) ***Auxiliary*** variables are converters/functions. Functions take information from other variables as an input and converts this into an information output. Auxiliary = $f(input_1, input_2,...,input_n)$. Auxiliaries can change values immediately.

e) ***Information links*** are used to give input to the auxiliaries and rate equations.

4.5.1   RC-circuit

Consider the RC circuit diagram in *Figure 4.8* corresponding to the set of equations - .

$$C \cdot \frac{du_2}{dt} = i \tag{i}$$

$$i = \frac{u_1 - u_2}{R} \tag{ii}$$

$$R = 10 \ \ k\Omega, C = 20 \ \ \mu F$$

The RC circuit is frequently used as low-pass filters in electric- and electronic apparatus. The CLD in *Figure 4.8b* explains the causal relationships between the components and should be read as follows: an increase in voltage *U1* increases the current *I* (rule (i) from section 4.4).   Furthermore, an increase of *I* increases the charge stored in the capacitor, which in turn increases the voltage *U2*. An increase in voltage *U2*, however decreases the current *I* (rule (ii) from section 4.4). Applying rule (iv) from section 4.4, we identify the loop as a negative feedback loop, which in system dynamic terms is called a balancing loop. CLDs are

Figure 4.8 Low-pass filter

a) RC Circuit diagram
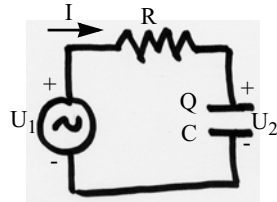
b) Causal loop diagram
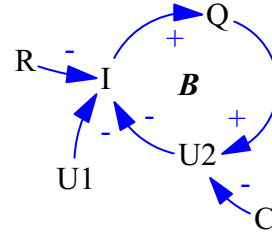
c) Stock & flow diagram
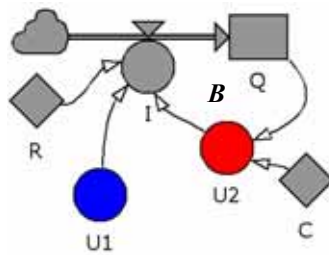
d) Block diagram
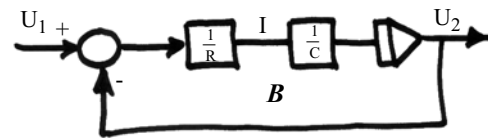
useful for initial analyses and for characterising systems, but lack dynamic information. For instance, which variable is a stock and which is a flow? Stock and flow diagrams (SFD) incorporate such information. The SFD diagram and the corresponding block diagram in *Figure 4.8c* distinguish between stocks (integrators) and flows (derivatives). Also, observe the feedback loop *B* in all of the diagrams. Equations Eq. 4.1 - Eq. 4.6 show the integral equations corresponding to the SFD diagram. The simulation results in *Figure 4.9* show the re-

Figure 4.9 RC-filter response of a step increase in U1 (left), a low-frequent sinus (above right) and a high-frequent sinus (lower right)
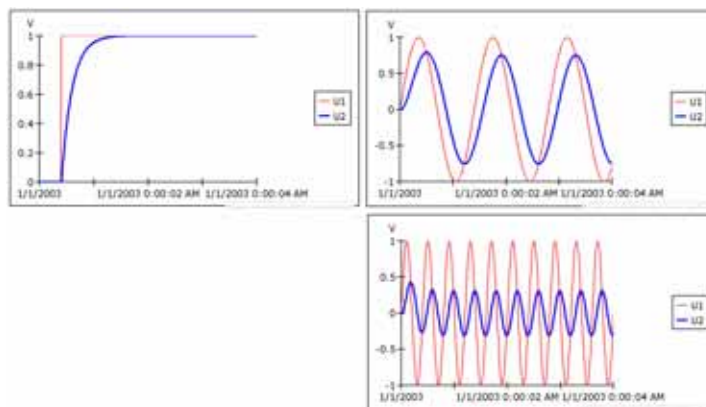
sponse of three various inputs : a step increase in *U1*, and sinusoidal input's with low and high frequencies. As expected, the RC-filter reduces the amplitude of the high-frequent signal, while the low-frequent signal remains almost unaltered.

RC circuit stock & flow equations

4.1 $\quad Q_t = Q_0 + \int i_t \cdot dt$ $\hfill$ [C]

4.2 $\quad i_t = (U1-U2)/R$ $\hfill$ [A]

4.3 $\quad U2 = Q/C$ $\hfill$ [V]

4.4 $\quad R = 10$ $\hfill$ [kOhm]

4.5 $\quad C = 20$ $\hfill$ [microFarad]

4.6 $\quad Q_0 = 0$ $\hfill$ [C]

Level variables are expressed with time index *t* when the integral equation is defined (Eq. 4.1). Level variables start with capital letters. When used in other equations, the time index is omitted (Eq. 4.3). Rate equations are expressed with time index *t* (Eq. 4.2). Auxiliary variables do not use time indexes (Eq. 4.3) Constants start with capital letters (Eq. 4.4). All variables must be specified with units that have real world counterparts.

4.5.2 DC motor

Consider the DC electrical motor in *Figure 4.10* described through the equations - .

$$L_a \cdot \frac{di_a}{dt} = u_a - R_a \cdot i_a - e_a \qquad (iii)$$

$$J \cdot \frac{d\omega}{dt} = K_T \cdot i_a - B \cdot \omega - T_L \qquad (iv)$$

$$e_a = K_e \cdot \omega \qquad (v)$$

where u_a, i_a, e_a is the anchor voltage, current and voltage over the DC motor; ω denotes the shaft speed, K_e is the voltage constant of the motor, B the damping torque, J the inertia of the motor, and T_L the load torque (see stock & flow equations for units and parameter values). The corresponding block diagram and SFD diagram is shown in *Figure 4.10*. Here, we can also identify the feedback loops B1, B2 and B3 in the diagrams, which can be used to determine the behaviour of the system. Corresponding stock and flow equations are represented below in Eq. 4.7- La = 6.4 [mH].

Figure 4.10 Block diagram representation of a DC motor and the corresponding SFD diagram. Simulation results from a step increase in U$_a$

a) DC motor

b) Block diagram

c) SFD DC motor

d) Simulation from SFD
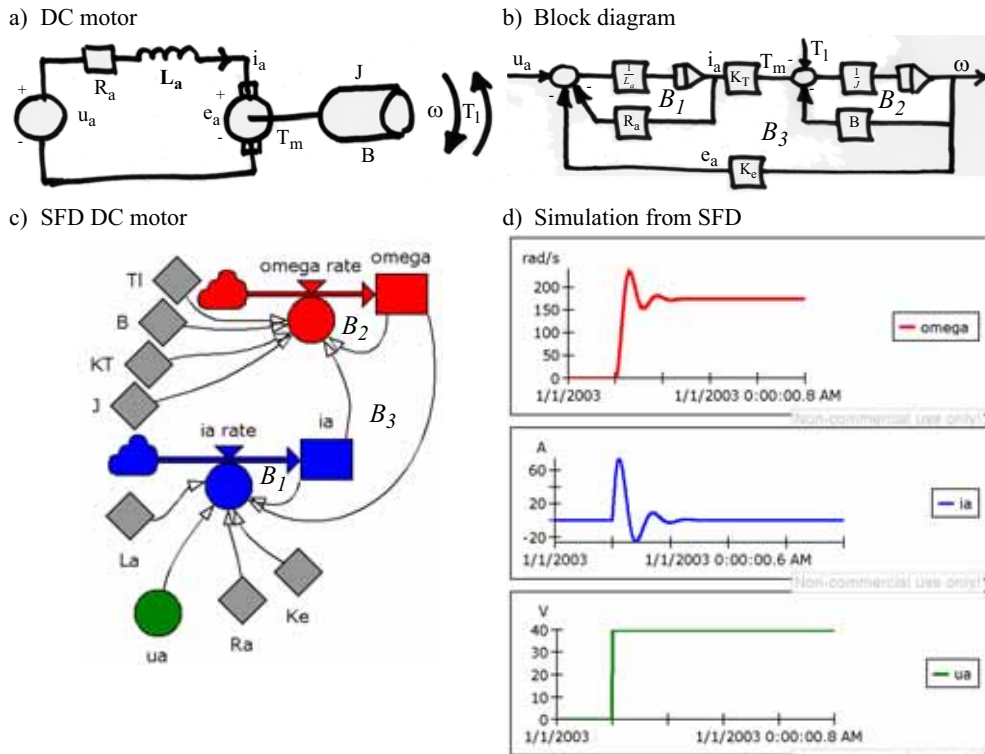
DC motor Stock & flow equations

4.7	$Ia_t = Ia_0 + \int ia\ rate_t \cdot dt$	[A]
4.8	$ia\ rate_t = (ua - Ra \cdot ia - Ke \cdot omega)/La$	[A/s]
4.9	$Omega_t = Omega_0 + \int omega\ rate_t \cdot dt$	[rad/s]
4.10	$omega\ rate_t = (KT \cdot Ia - B \cdot Omega - Tl)/J$	[rad/s^2]
4.11	$J = 26$	[kg·cm^2]
4.12	$KT = 23$	[N·cm/A]
4.13	$B = 0.017$	[N·cm/(rad/s)]
4.14	$Tl = 10$	[N·cm]
4.15	$Ke = 0.3$	[V/(rad/s)]
4.16	$Ra = 0.25$	[Ohm]
4.17	$La = 6.4$	[mH]

Tools and methods from linear control theory are of course much better suited to analyse these technical systems than SFD and system dynamics. The purpose here is to show the similarities of the approaches, which should come as no surprise knowing the origin of system dynamics. However, the useful tools within control theory are mainly restricted to LTI systems and the focus is mainly on stability analysis and the design of negative feedback control systems. System dynamics has its application on highly nonlinear feedback systems - the class to which social and economic systems belong. So lets have a look at two representative

problems of these systems. The following section deals with a sales organisation as a socio-economic system at the micro-level, which can be found within any firm or company. The subsequent section deals with the price formation in the marketplace.

4.5.3   Sales growth

This is an example taken from Forresters *Principle of Systems* (1971), and is a part of Forrester's paper *"Market Growth as Influenced by Capital Investments"* (Forrester, 1958). The model displays the growth of a company in an unlimited market. Even when demand is unlimited, growth and profitability can collapse by overloading the production capacity of the company. *Figure 4.12a)* shows the CLD of a sales department and the flow of incoming and

Figure 4.11 Forrester's sales growth model

a)   CLD, sales growth
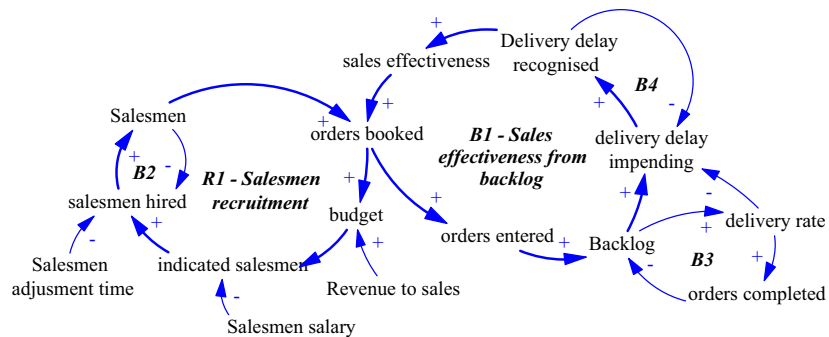
b)   SFD, sales growth
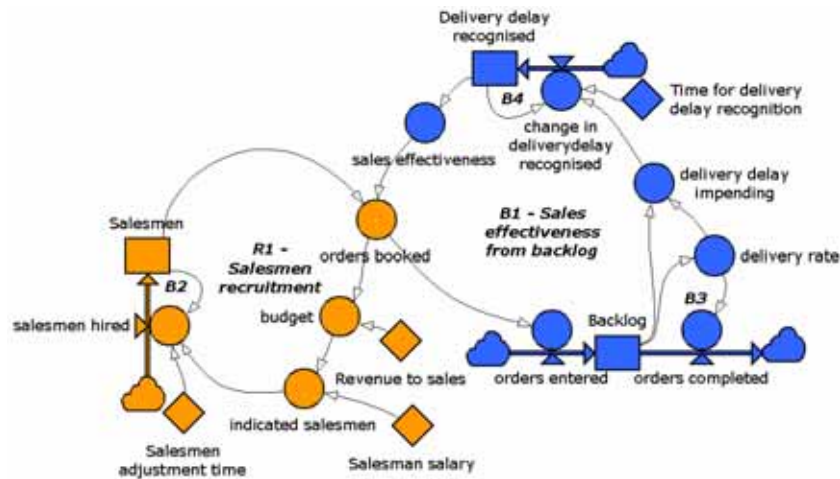
completed orders. The reinforcing feedback loop (R1) - is the growth engine of the company that controls the number of salesmen as a simple first-order process as can be seen in in the corresponding SFD in *Figure 4.12b*. The balancing loop denoted B1 describes the backlog of orders and the delays of perceiving delivery delays. This process is represented as a sec-

ond-order process. These two loops are connected through the delivery delay recognised by the customers. In this model, only the time delays of delivery are assumed to affect the attractiveness of the product. As delivery delays increase, the product becomes increasingly more difficult to sell. While the company increase the sales by generating more revenue from sales, new salesmen are hired to generate more revenue . This is the growth engine of the company,

Figure 4.12 Sales growth model (replicated from Forrester 1971 sec 2.5)

a) Backlog

b) Salesmen

c) Delivery rate and orders booked

d) Sales effectiveness

e) Delivery rate impending and delivery rate recognised

f)
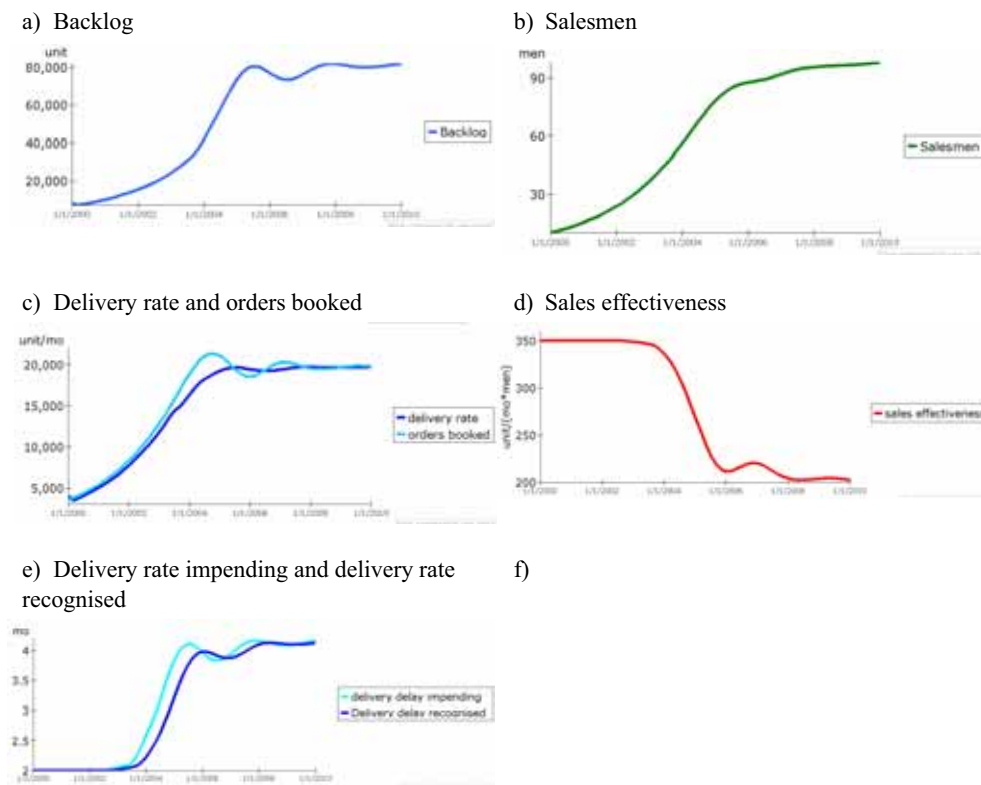
and through the first stages of the model, the order rate grows exponentially (*Figure 4.12*c). However as the order rate increases the delivery rate cannot keep pace due to manufacturing capacity constraints. This relationship is shown in Eq. 4.28 and the corresponding graph in *Figure 4.13c)*.   Further increases of delivery rates can only come from increasing labour or production capacity, which is assumed to be fixed in this example[1]. At the beginning of the phase, increasing orders can be met by the production capacity, and there is no increase in delivery delays (*Figure 4.13e)*. But as the delivery delay cannot keep pace with increasing backlog, delivery delays increase. The example serves to pinpoint some important concepts of system dynamics. The model distinguishes between delivery delay impending and delivery delay recognised (*Figure 4.13e)*, because it will take some time before the delivery delays are perceived by customers and decision-makers. Information delays are important, factors and hence, it is important to distinguisih between actual values and perceived values. In this example, delivery delays recognised adjusts as an adaptive expectation process, where for

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1. The article *"Market Growth as Influenced by Capital Investment"* (Forrester, 1958) includes the capacity investment loop in the sales growth model.

each time step - the delivery delay recognised is adjusted according to the discrepancy between delivery delay impending and delivery delay recognised over the time for delivery delay recognition (Eq. 4.31).   As delivery delays increase, the sales effectiveness drops dramatically (*Figure 4.13d*).   The flows included here are stocks and flows of salesmen (labour) and stocks and flows of information (backlog and delivery delays).

Figure 4.13 Graphical functions used in the Sales growth model

a) Delivery rate as a function of backlog
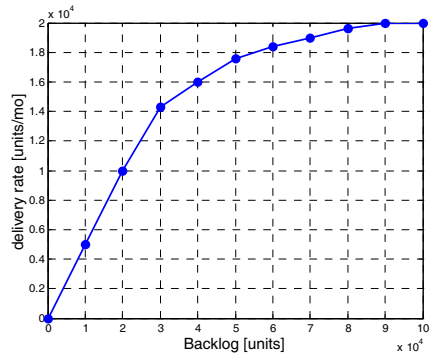
b) Sales effectiveness as a function of delivery delay recognised
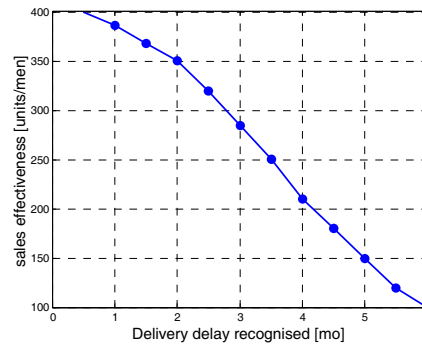
Sales growth model

4.18	$Salesmen_t = Salesmen_0 + \int salesmen\ hired_t \cdot dt$	*[men]*
4.19	*orders booked = Salesmen·sales effectiveness*	*[units/mo]*
4.20	*budget = orders booked·Revenue to sales*	*[$/mo]*
4.21	*Revenue to sales = 10*	*[$/unit]*
4.22	*indicated salesmen = budget/Salesmen salary*	*[men]*
4.23	*Salesmen salary = 2000*	*[$/(men·mo)]*
4.24	$salesmen\ hired_t = (indicated\text{-}Salesmen)/Salesmen\ adjustment\ time$	*[men/mo]*
4.25	*Salesmen adjustment time = 20*	*[mo]*

4.26	$orders\ entered_t = orders\ booked$	*[units/mo]*
4.27	$Backlog_t = Backlog_0 + \int (orders\ entered_t - orders\ completed_t) \cdot dt$	*[units]*
4.28	*delivery rate=GRAPH(Backlog,0,10e3,{0 5e3 10e3 14.3e3 16e3 17.6e3 18.4e3 19e3 19.6e3 20e3 20e3})*	*[units/mo]*
4.29	$orders\ completed_t = delivery\ rate$	*[units/mo]*
4.30	*delivery delay impending = Backlog/delivery rate*	*[mo]*
4.31	$change\ in\ delivery\ delay\ recognised_t = (delivery\ delay\ impending\text{-}Delivery\ delay\ recognised)/Time\ for\ delivery\ delay\ recognition$	*[mo]*
4.32	*Time for delivery delay recognition = 6*	*[mo]*
4.33	$Delivery\ delay\ recognised_t = Delivery\ delay\ recognised_0 + \int change\ in\ delivery\ delay\ recognised_t \cdot dt$	*[mo]*
4.34	*sales effectiveness = GRAPH(Delivery delay recognised,0,0.5,{400 400 386 368 350 320 285 250 210 180 150 120 100})*	*[units/men]*

4.5.4   Market dynamics

Another example is how prices form in a market. *Figure 4.14a)* shows the market cross at two time instants. Comparative static analysis is the examination of market equilibrium before and after a policy change (Schotter, 2001). In other words it is assumed that equilibrium is reached rapidly. But how does the market move from equilibrium point 1 at t_1 to point 2 at time t_2 ?

Suppose the supply and demand curves are given by

$$S_t = S_{eq} \cdot \left(\frac{p_t}{p_{eq}}\right)^{\varepsilon_s} \qquad\qquad (vi)$$

$$D_t = D_{eq} \cdot \left(\frac{p_t}{p_{eq}}\right)^{\varepsilon_d} \qquad\qquad (vii)$$

Where $(S_{eq}\ p_{eq})$ is the equilibrium point at t_1. The market reaches equilibrium when $D_t = S_t$. Inspection of Eq. (vi) suggests that the producer must somehow know the price p_t in advance of producing the commodity S_t because there are time delays in the production processes. *Rational expectations* assume that the agents are able to predict market prices accurately. However cumulative evidences reject this theory of *rational expectations* in favour of *adaptive*

expectations (Williams, 1987) Price formation is an adaptive process in which agents adjust their expectations of price based on a limited amount of information prior to their decisions. .In well-behaving, double-auction markets, prices normally converge towards the equilibri-

Figure 4.14 Market dynamics.

a) Static market cross
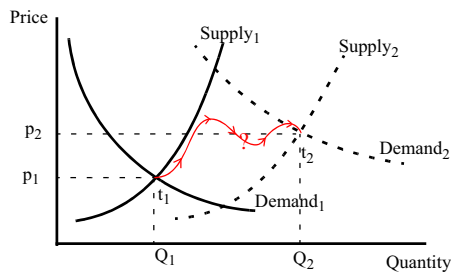
b) CLD Market dynamics
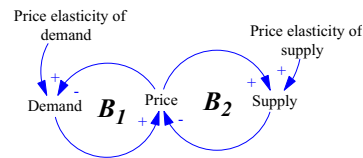
c) SFD Market dynamics
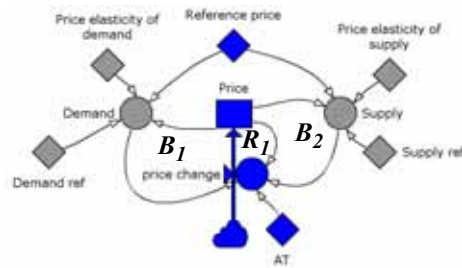
d) Simulation exogenous demand
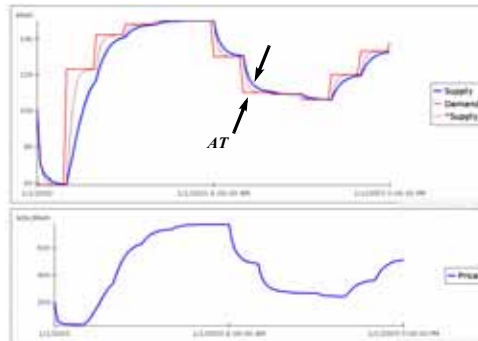
e) Simulation 10% step increase in demand
f)
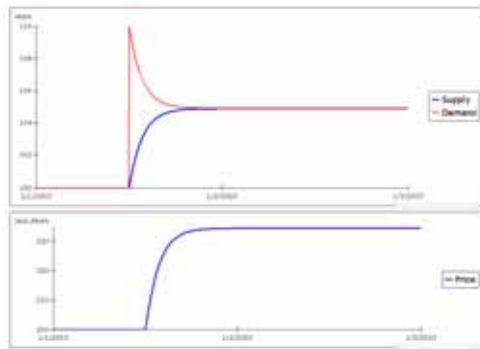
g) Simulation with added pink noise μ = 0 max = +/- 30 MWh 1 day autocorrelation time
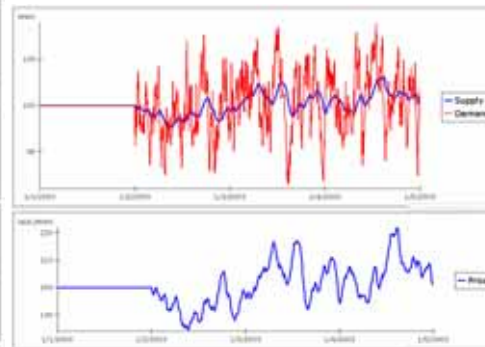
um price as predicted by neoclassical economic theory - if exogenous factors are kept constant throughout this process. We can thus describe price formation as two balancing loops as shown in *Figure 4.14*b. The SFD is shown in *Figure 4.14*c and the corresponding stock and flow equations are shown below. Price is modelled as a level that adjusts up or down for each time step, proportional to the fractional discrepancy between demand and supply in *Eq. 4.36*. where the time constant AT (adjustment time) represents the average time to clear the market.

Market dynamics

4.35 $Price_t = Price_0 + \int price\ change_t \cdot dt$ [NOK/unit]

4.36 $price\ change_t = Price \cdot (Demand-Supply)/Demand \cdot 1/AT$ [NOK/unit/hr]

4.37 $Supply = Supply_{ref} \cdot (Price/Price_{ref})^{Es}$ [Units]

4.38 $Demand = Demand_{ref} \cdot (Price/Price_{ref})^{Ed}$ [Units]

4.39 $Es = 0.3$ [1]

4.40 $Ed = -0.2$ [1]

4.41 $AT = 1$ [hr]

4.42 $Price_{ref} = 200$ [NOK/unit]

4.43 $Supply_{ref} = 100$ [Units]

4.44 $Demand_{ref} = 100$ // Demand is also exogenously varied   [Units]

Pink noise[1] - example

4.45 $Pink\ noise_t = Pink\ noise_0 + \int chg\ in\ pink\ noise_t \cdot dt$ [Units]

4.46 $chg\ in\ pink\ noise_t = (Pinkt\ noise_t - RANDOM(-30\ 30))/Correlation\ time$ [Units/hr]

4.47 $Correlation\ time = 1$ [hr]

*Figure 4.14*d shows how supply responds to an exogenous change in demand over a period of 12 hours. Here, supply adjusts to prices (lower graph in *Figure 4.14*d) as a first order response. In *Figure 4.14*e, we see the response of a step change in demand . Both the supply and demand sides respond due to the price elasticities (Es and Ed in Eq. 4.39-6) and   settles at a new price level. In *Figure 4.14*f, pink noise is added to demand to represent continuous perturbations. Supply tries to adjust accordingly, but there is always some gap between supply and demand and the prices fluctuate continuously, very much like real world markets.

This process of continuous adjustment to a changing goal (demand) can be recognised as a simple search process referred to as a *hill-climbing search* (Sterman, 2000). Optimisation is in practice a search process according to predefined goals. The hill-climbing structure of the market cross is here interpreted as a continuous search to minimise the discrepancy between demand and supply, while keeping the price level as a decision variable. The closer we want to approach the equilibrium point at all times, the smaller the adjustment time AT in Eq. 4.41. The convergence of demand and supply in relation to AT is shown in *Figure 4.14d)*.

4.6   Concluding remarks

From the above examples, we have seen the same basic structures and the same basic patterns reappear in systems thought to be widely different, from the low-pass filter and DC current motor, to price formation in markets and behaviour within organisations. Perceptions of important factors such as prices and backlog are formed through adaptive expectations.

Adaptive expectations in turn, posess the same basic structure as low-pass filters. In principle, all systems can be described in terms of reinforcing or balancing first-order processes that interact in complex feedback networks to produce all kinds of complex behaviour. The complex behaviour that arises from within these systems can then be understood by inspecting its structure.

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1. Note that pink noise as modeled in eq. *4.45-4.47* can be recognised as low-pass filtered uniform random noise (i.e., white noise).

In the context of electrical engineering education, where education is diversifying into fields of electrical engineering, economics, management and environmental science - learning could be significantly enhanced by recognising the underlying structures that recur in all of these systems than if taught under separate theoretical approaches (Radzicki, 2002).

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5   A simplified model of the Nordic electricity market

In this chapter a simplified model of the Nordic electricity market is developed from which a more detailed model will be elaborated.   Structural and parameter sensitivity analyses on the simplified model helps us identify the important parts of the model structure which is useful for the more comprehensive model.   More detailed explanation for each of the model sectors is provided in the subsequent chapters each dealing with one of the model sectors.
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5.1   The electricity 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 settles the market spot price for each hour, which is the most important information for decision makers on the supply side. Additional market based services could be the TGC market and the CO2-quota market plus the already existing futures market 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 give rise to stronger price variations. Thus, imposing transmission constraints will tend to amplify the mechanisms caused by the feedback loops in *Figure 5.1*.

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 choose to include. For this reason, we have chosen a 30-year time horison, 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 so, we are able to simulate the capacity factor (utilisation time) for each generation technology. Capacity utilisation 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. Seasonal variation will determine how much of the renewable capacity is utilised during a year. The interplay between the different generation technologies with respect to the short term (generation scheduling, capacity acquisition) and long-term (technology progress resource availability) is the focus in this thesis.

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.

For simplicity, we only distinguish between *thermal generation*, *hydropower* and *renewables* motivated by their differing operational characteristics. Hydropower is indeed renewable, but the distinction between hydropower and renewables is motivated by the operational characteristics where large-scale hydropower is operated by the market price, while renewables such as wind and CHP biomass is not scheduled by the market price.

Figure 5.1 Causal loop diagram of the Nordic electricity market and the main feedback mechanisms that influence the long-term development of each technology
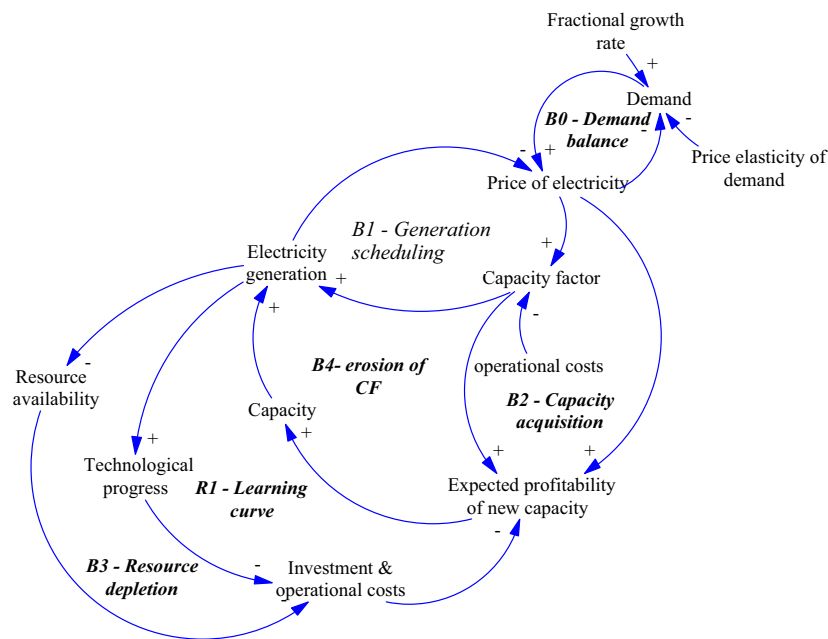
Figure 5.1 shows the main feedback loops that influence the development of electricity generation technologies.

Generation scheduling (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 commissioned. The last unit in operation determine the spot price at each time point (see *Figure 5.3* for details on the supply curve of thermal generation).

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 is typically a tedious process while less time delays are involved in wind power and biomass with usually fewer stakeholders.

The learning curve (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 we assume that the availability of fossil resources does not constrain thermal 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.

Figure 5.2 shows the stock and flow (SFD) diagram of the simplified model. The balancing loops correspond to those of the CLD diagram in *Figure 5.1*. Each symbol with double edges is vectors or arrays while the single-edged symbols contain scalar values. As can be seen from the diagram, the model is subdivided into the following sectors : *Electricity market, Generation scheduling, Profitability assessment, Capacity acquisition, Technology progress, Resource availability* and *Demand*. In the following sections, each sector will be described mathematically.

Figure 5.2 Stock & flow diagram of the Nordic electricity market.
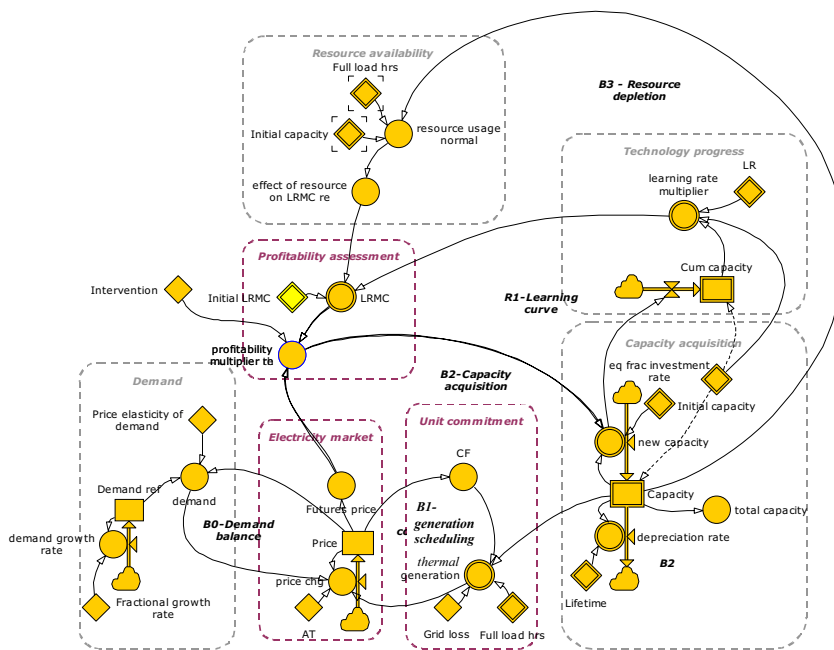
5.2   Market dynamics

The Nord Pool electricity market is a double-auction market that clears every hour. Approximately 30% of all electricity is traded through the spot market the remaining share is traded through bilateral contracts or long-term contracts. The time constant for the spot market is set to 1 week - enough to give a good estimate of how the capacity factor (capacity uti-

lisation) changes with seasonal load patterns. The market dynamics formulation is given in the Market dynamics submodel, where spot price is a level that adjusts in proportion to the fractional demand/supply balance.

Market dynamics submodel

5.1 $Spot\ price_t = Spot\ price_0 + \int chg\ in\ price_t \cdot dt$ [NOK/MWh]

5.2 $chg\ in\ price_t = Spot\ price \cdot (demand\text{-}generation)/demand \cdot 1/Market\ AT$ [NOK/MWh/da]

5.3   *Market adjustment time = 7*   [da]

5.4 $Spot\ price_0 = 200$ [NOK/MWh]

The Nord Pool futures market represents the joint expectations of market participants where contracts for electricity can be traded up to 4 years ahead. This market is used as an indicator when investment decisions for new capacity are being made. The expected future spot prices are modelled as an adaptive trend extrapolation (Eq. 5.5) of prior average spot market prices (Eq. 5.6) where the smoothing time horizon is 3 years and the forward time horizon is 2 years.

5.5   *Futures market price = FORECAST(Yearly avg price, 3, 2)*   [NOK/MWh]

5.6   *Yearly avg price = SLIDINGAVERAGE(Spot price, 1)*   [NOK/MWh]

5.3   Demand side

The demand side is kept simple in our model as the focus is on the supply side. Demand is modelled using a Cobb-Douglas function in the *Demand side submodel* equation set with a price elasticity of demand equal to -0.3 1/yr, although the reported estimates vary from -0.2 to -0.8 (NOU 1998 99; Econ 1999 11; Groenheit & Larsen 2001 46). When simulating over 20 years, demand and price elasticity's will change significantly. It is beyond the scope of this model to address long-term changes in consumption. Changes in consumption are therefore represented through the fractional demand growth rate, which can be set exogenously and price elasticity of demand (yearly elasticity). All reference values refer to data from the year 2000.

Demand side submodel

5.7 $demand = Demand\ ref \cdot (Spot\ price/Reference\ price)^{Price\ elasticity\ of\ demand}$ [TWh/yr]

5.8   *Reference price = 200*   [NOK/MWh]

5.9   *Price elasticity of demand = -0.3*   [1]

5.10 $Demand\ ref_t = Demand\ ref_0 + \int demand\ growth\ rate_t \cdot dt$ [TWh/yr]

5.11 $Demand\ ref_0 = 417$ [TWh/yr]

5.12 $demand\ growth\ rate_t = Fractional\ growth\ rate \cdot Demand\ ref$ [TWh/yr^2]

5.13   *Fractional growth rate = 1.2*   [%/yr]

Note here that reference demand differs in Eq. 5.11 from observed demand in 2000 (384 TWh/yr). We deliberately chose a demand that assured the model initially to be in long-term equilibrium to ease our analysis with the simplified model. This discrepancy is due to the

overcapacity that still persists after deregulation, which is expected to balance around 2010. In the full model however, demand corresponds to observed demand.

5.4 Generation scheduling

Electricity is rather at service than a commodity, and share many common features of service sectors. In service sectors, such as the airline industry, services must be produced in a timely manner. In the same way as airlines cannot store flights electricity as a service cannot be stored. For this reason, the generation capacity of electricity must be flexible to meet consumption at all times. Units are scheduled after increasing marginal operational costs, as can be seen from *Figure 5.3*. Normalising the below graph with total installed capacity yields the *capacity factor* CF varying between 0 and 1, which is the maximum capacity utilisation. The stock & flow equations for the generation scheduling are presented as follows:

Generation scheduling submodel

5.14   *generation$_{th}$= CF·Max full load hrs* [TWh/yr]

5.15   *CF=GRAPH(Spot price$_t$ 0 50 {0 0.014 0.11 0.58 0.82 0.914 0.94 0.98 1 1})* [1]

5.16   *Max full load hrs = 8000* [hr/yr]

The marginal operational costs of hydropower are neglible and hydropower units with reservoirs use *incremental water values* that represent the 'marginal costs' of hydropower. The water value is defined as the marginal change of expected future cumulative profits from storing one additional unit of water. This problem can be solved using stochastic dynamic optimisation. *Chapter 17* provides a detailed study of the hydropower scheduling problem,

which is also represented in the detailed Kraftsim model. For the simplified model, hydro-power is represented with constant capacity utilisation.

5.17   *generation$_{hy}$ = Capacity$_{hy}$·Avg full load hrs$_{hy}$*   *[TWh/yr]*

5.18   *Avg full load hrs$_{hy}$ = 4800 (or 4500)*   *[hr/yr]*

5.19   *Capacity$_{hy}$= 41600*   *[MW]*

5.20   *generation$_{re}$= Capacity$_{re}$·Avg full load hrs$_{re}$*   *[TWh/yr]*

5.21   *Avg full load hrs$_{re}$ = 3350*   *[hr/yr]*

Figure 5.3 Capacity factor based on marginal production costs of thermal units

a)
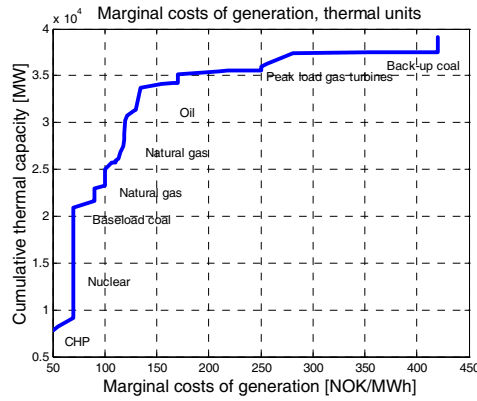
Here full load hours represent the average of hydropower units and for renewables, they represent the weighted average of present bio energy and wind power. Total generation is the sum of generation from each technology minus grid losses:

5.22   *generation =(1-Grid losses)·$\sum_{i \in T}$ generation$_i$*   *[TWh/yr]*

5.23   *Grid losses = 0.1*   *[1]*

where $T = \{th, re, hy\}$

An important difference between renewables and thermal generation is the inability to control generation according to prices. Some bio/waste incineration units or small-scale hy-dropower (defined as new renewable) with reservoirs do operate after marginal costs but it is a good approximation to regard short-term renewable generation as inelastic. In other words, renewable technologies lack the *Generation Scheduling loop B1*. The level of renew-able generation is therefore determined by the long-term *capacity acquisition loop B3* in combination with the stochastic properties of wind and water, which is not included in the simplified model. As we will see later on, this has important implications for the TGC mar-ket.

5.5 Profitability assessment and capacity acquisition

In the short term, electricity generation is adjusted by the processes described by the *Generation scheduling* feedback loop in response to short-term demand variations. In the long term, expectations of future prices govern the investment of new capacity. If the expectations of future spot market prices are significantly higher than the *long-run marginal costs* (LRMC) of new generation capacity investments in new capacity are made. Holding the futures market price (Eq. 5.5) up against LRMC for thermal generation (Eq. 5.25) in Eq. 5.24 indicates the *effect of profitability on investment rate* shown in *Figure 5.4*. When futures mar-

Figure 5.4 Effect of profitability on investment rate
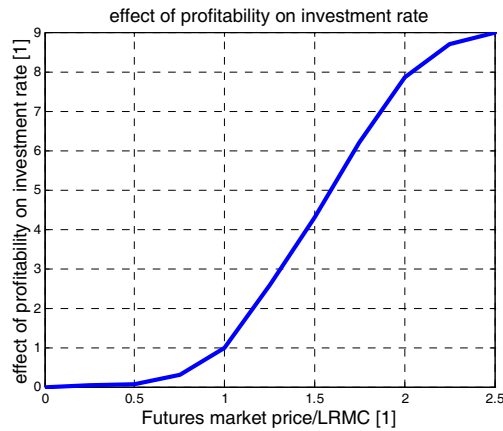
a)

ket price equals LRMC, the effect of profitability on investment rate returns 1 at which the investment rate is in *dynamic equilibrium* with the depreciation rate of that technology. When the futures market price significantly exceeds LRMC the investment rate increases up to a certain limit that corresponds to a maximum 45% growth rate. Growth within the power industry is limited by the availability of service and material from other industrial sectors. The shape of the curve in *Figure 5.4* can be recognised as a cumulative probability density function that represents the aggregate of a large number of possible profitable projects which would differ in costs. The long-run marginal costs can be represented by a more disaggregated *net present value calculation* including profitability requirements, capacity factor, investment costs and operational costs. This has been done in the detailed model.

Profitability assessment submodel

5.24 *effect of profitability on investment rate$_i$= GRAPH(Futures market price/(LRMC$_i$+Support scheme$_i$) 0 0.25 {0 0.03 0.06 0.3 1 2.6 4.3 6.2 7.86 8.7 9})*   *[1]*

5.25 *LRMC$_i$ = Initial LRMC$_i$·learning multiplier$_i$·resource multiplier$_i$*   *[NOK/MWh]*

5.26 *Initial LRMC$_i$ = [200 275 300]*   *[NOK/MWh]*

5.27 *Incentives$_i$ = [0 100 0]*   *[NOK/MWh]*

Authorities can influence the profitability of new projects by taxes and subsidies for investments. This is represented in the support scheme Eq. 5.27 where taxes are negative and subsidies positive values.

It should be pointed out that the Nord Pool power market is not in long-term equilibrium. A long-term (economic) equilibrium exists when the spot price equals the long-run marginal costs of new generation. For our case the market is in long-term equilibrium when the futures market price equals the long run marginal costs of the generation technologies, that is:

Futures market price = min { LRMC$_i$ + Support scheme$_i$ }   *(i)*

If this is not the case the installed capacity of thermal and/or renewables and thereby long-term prices will change. To simplify our study we assume the electricity market to be initially in equilibrium at a spot price of 200 NOK/MWh (which is the current observed futures price in the Nord Pool market) and by letting LRMC thermal equal 200 NOK/MWh while LRMC renewables is set to 300 NOK/MWh requiring 100 NOK/MWh in subsidies to maintain present installed capacity.

The futures market price is now approaching long run marginal costs of new generation while recent years have shown average market prices of around 157 NOK/MWh which is far below LRMC for new generation. Noteworthy the futures price history from 1998-2000 (*Figure 7.2* in *Chapter 7*) shows a declining trend. Expectations of lower prices during the first years of deregulation can be attributed to the expectations of increased competition efficiency that more than compensates for reduction of overcapacity. Some partial equilibrium models with endogenous investments assume markets to be in long-term equilibrium although this is rarely the case in real world.

Much of the considerable variation, which distorts the price signals, is subject to the large variations of hydro inflow from year to year. Hydropower generation can vary as much as +/-40% in a system where hydropower accounts for 61% of electricity generation during normal years of hydro inflow. This problem is not encountered here in our simplified model as we use normal years of hydrological conditions omitting the stochasticity of hydropower. The lifetime of thermal units is set to 30 years and renewables to 20 years. Thus the equilibrium fractional investment rate sufficient to match this rate is 3.33 %/year and 5 %/yr respectively. Initial thermal capacity of 37360 MW and renewable capacity of 5685[1] correspond to the year 2000 situation for the Nord Pool market.

Capacity acquisition submodel $\forall\ i \in T$

5.28   *Capacity$_{i,t}$ = Capacity thermal$_{i,0}$ + ∫ (new capacity$_i$ - depreciation rate$_i$) ·dt   [MW]*

5.29   *new capacity$_{i,t}$ = Equilibrium fractional investment rate$_i$·effect of profitability on investment rate$_i$·Capacity$_i$*   *[MW/yr]*

5.30   *depreciation rate$_{i,t}$ = Capacity$_i$/Lifetime$_i$*   *[MW/yr]*

5.31   *Equilibrium fractional investment rate$_i$= [3.33 5 2.5]*   *[%/yr]*

5.32   *Lifetime$_i$= [30 20 ∞]*   *[yr]*

5.33   *Capacity$_{i\ 0}$ = [37360 5585 41600]*   *[MW]*

A question that immediately arise is the representation of re-investments or retrofitting of plants. For hydropower the lifetime is set to infinity as all of the existing capacities most likely is to be maintained profitably. Renewables may also be considered for upgrade when considering the rapid technological development. Furthermore old sites with thermal units

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1.   Renewable capacity is calculated as the sum of wind power and biomass installed in 2001 with a corresponding full load hour utilisation.

i.e. coal plants can be retrofitted at lower costs to gas power or gas power plants - especially in Denmark. The effects of retrofitting and upgrade is not taken into account here.

5.6 Technology progress

Technology progress equation set defines the long-run marginal costs as a function of the technological progress estimated as proportional to the cumulative installed capacity. The learning index is afflicted with high uncertainty, particularly in the early stage of a technology. As the installed capacity grows, more experience with the technology cumulates and uncertainties are reduced. Such considerations will be addressed later in the modeling stage during the parameter sensitivity analysis. Noteworthy, technology progress is the only major *reinforcing* identified for the long-term development of the electricity market. While balancing loops oppose changes reinforcing loops when stimulated amplify changes. This means that the learning curve effect is a high leverage point for long-term policymaking if we want to alter the course of development. A further discussion of technology progress and the underpinnings of this sector is left for *Chapter 11*. For now we represent technological progress as a multiplier influencing long-run marginal costs of technologies where the learning rate is a function of cumulative installed capacity and the learning index defined as the fractional change in cost reductions in for each doubling of cumulative capacity.

Technology progress $\forall \, i \in T$

5.34 $Cumulative \ capacity_{i \, t} = Cumulative \ capacity_{i \, 0} + \int new \ capacity_{i \, t} \cdot dt$ *[TWh/yr]*

5.35 $Cumulative \ capacity_{i \, 0} = \ Capacity_{i \, 0}$ *[TWh/yr]*

5.36 $learning \ rate \ multiplier_i = (Cumulative \ capacity_i \ / \ Capacity_{i \, 0})^{Learning \ index_i}$ *[1]*

5.37 $Learning \ index_i = [0.05 \ 0.2 \ 0]$ *[1]*

5.7 Resource availability

The ultimate constraining loop is the availability of resources. There is usually a great deal of uncertainty in the estimate of resource potentials, mostly because the estimates themselves rely on assumptions about technology costs and public acceptability.

Resource availability submodel $\forall \, i \in T$

5.38 $resource \ usage \ normal_i = Capacity_i \cdot Full \ load \ hrs_i / Capacity_{i \, 0} \cdot Full \ load \ hrs_i$ *[1]*

5.39 $resource \ multiplier_{re} = GRAPH(resource \ usage \ normal_{re} \ 1 \ 10 \ \{1 \ 1.4 \ 1.9 \ 2.5 \ 3.3 \ 4.5\})$ *[1]*

5.40 $resource \ multiplier_{hy} = GRAPH(resource \ usage \ normal_{hy} \ 1 \ 0.0125 \ \{50 \ 140 \ 170 \ 200$
   $225 \ 250 \ 265 \ 290 \ 310 \ 340 \ 400 \ 450 \ 1000\})$ *[1]*

5.41 $resource \ multiplier_{th} = 1$ *[1]*

The long-run marginal costs of thermal generation is assumed not to be significantly influenced by the resource availability over the simulation period of 30 years. The user of the model can specify the fuel price. In most studies concerning the renewable potential, assumptions on growth rate, technology, and other feasibility constraints are made. In our model

technology and constraints on growth rates are explicitly represented through other sectors of the model. Data from the ReBUS project was adapted to our purpose and *Figure 5.5* shows some of the data for comparison. Rebus data span from realistic potential in 2010 (where maximum growth rates up to 2010 are imposed along with experts' evaluations). The technical potential from the Rebus project aggregated for bio and wind is also shown. For a sensitivity analysis, we have chosen to represent resources as marginally increasing normalised cost curves spanning between these ranges $R_{25\%}...R_{150\%}$ where R_{ref} is the reference closer to the technical potential in the Rebus study. The curves are normalised with the year 2000 in which the renewable resource usage was 17 TWh/yr and at a cost of 275 NOK/MWh.

Figure 5.5 Resource potential renewables (adapted from ReBUS)
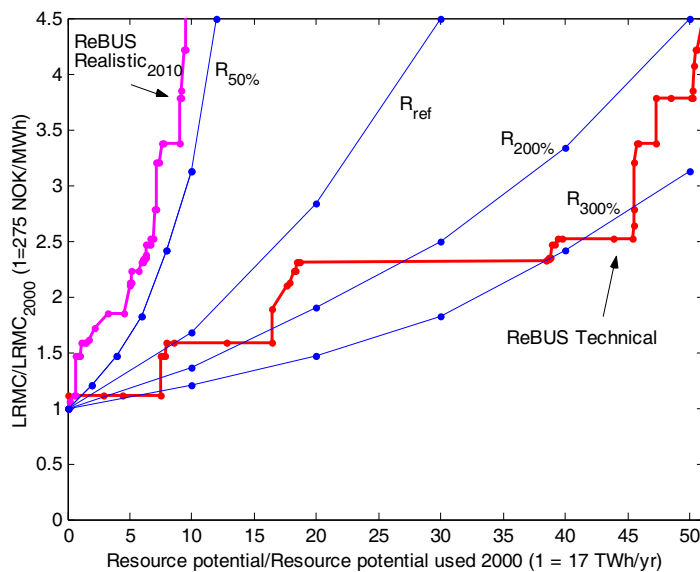
Hydropower is also represented as a resource in the same fashion. For hydropower we have used data on long-term marginal costs for remaining hydropower projects in Norway from NVE. Details on the resources and the resource data are provided in *Chapter 12*

5.8   Reference simulation

With this model, the characteristic long-term behaviour of the Nordic electricity market can be analysed. Assuming a 1.2% yearly increase in demand a price elasticity of -0.3 and the resource cost curve R_{ref} in *Figure 5.5* to represent resource availability the response is given in *Figure 5.6*. Note that these simulations start from an assumed state of equilibrium, in which the long-run marginal costs equal the market price. This is not the case for the current situation of the Nordic electricity market, where prices are rising until the investment rate in new capacity equals the depreciation rate of existing capacity. While installed capacity of hydropower is constant (an assumption in the simplified simulation), renewables shows a continued growth throughout the simulation period. Thermal generation shows initially growth, and levels out by the end of the simulation period. The net growth rate (new capacity

minus depreciation of old capacity) does however not exceed 15% yearly growth. By the end of the simulation period renewables dominate the share of total installed capacity.

Demand grows to 600 TWh/yr, which is a 50% increase from the initial level. Price elasticity of demand does not influence demand significantly as the electricity price remains around the 200 NOK/MWh throughout the simulation. Lower capacity utilisation of renewables makes the growth in generation less impressive although renewable generation approaches the level of hydropower by the end of the simulation period. Thermal generation peaks around 2020 before declining. This can also be observed by the capacity factor of thermal generation, which shows a weak decline throughout the simulation period.

Long-run marginal costs are compared with the electricity price. As already mentioned electricity price shows a small increase in the start of the simulation period around 2010 before declining thereafter. LRMC of thermal generation shows a slight reduction due to the learning curve effect. Renewables shows an initial decline in costs due to the learning curve effect, but at the same time, less profitable resources have to be developed. The lowest costs of renewables is reached somewhere before 2020 before the resource depletion loop (B3) starts to dominate over the learning curve effect reinforcing loop (R1). Renewables are subsidised by 100 NOK/MWh throughout the period and in the long run electricity market prices are determined by the lowest long-run marginal costs of new generation which in this case would be renewables. In the Nordic market gas power is presently the cheaper alternative and is currently setting the long-term prices in the electricity market (i.e. futures market prices). Due to the long time delays in capacity acquisition, electricity market prices here does not reach equilibrium with the cheapest alternative which is subsidised renewables.

Figure 5.6 Reference simulation : Fractional growth rate = 1.2 %/yr   Price elasticity of demand = -0.3 and R$_{ref}$ in *Figure 5.5* represents resource availability
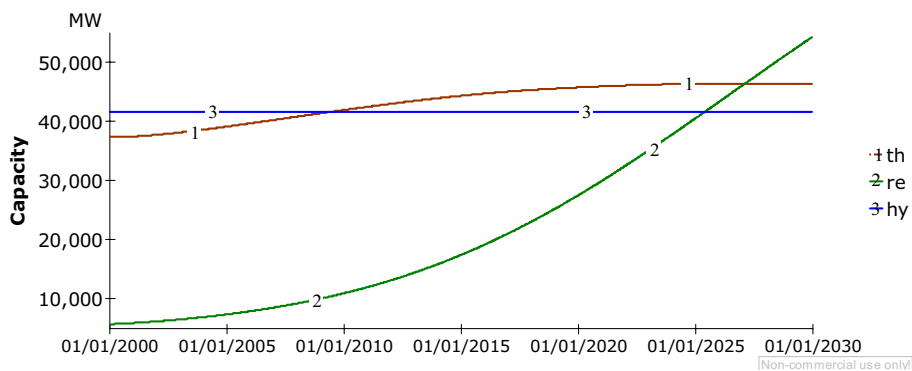
Figure 5.6 Reference simulation : Fractional growth rate = 1.2 %/yr   Price elasticity of demand = -0.3 and R_{ref} in *Figure 5.5* represents resource availability
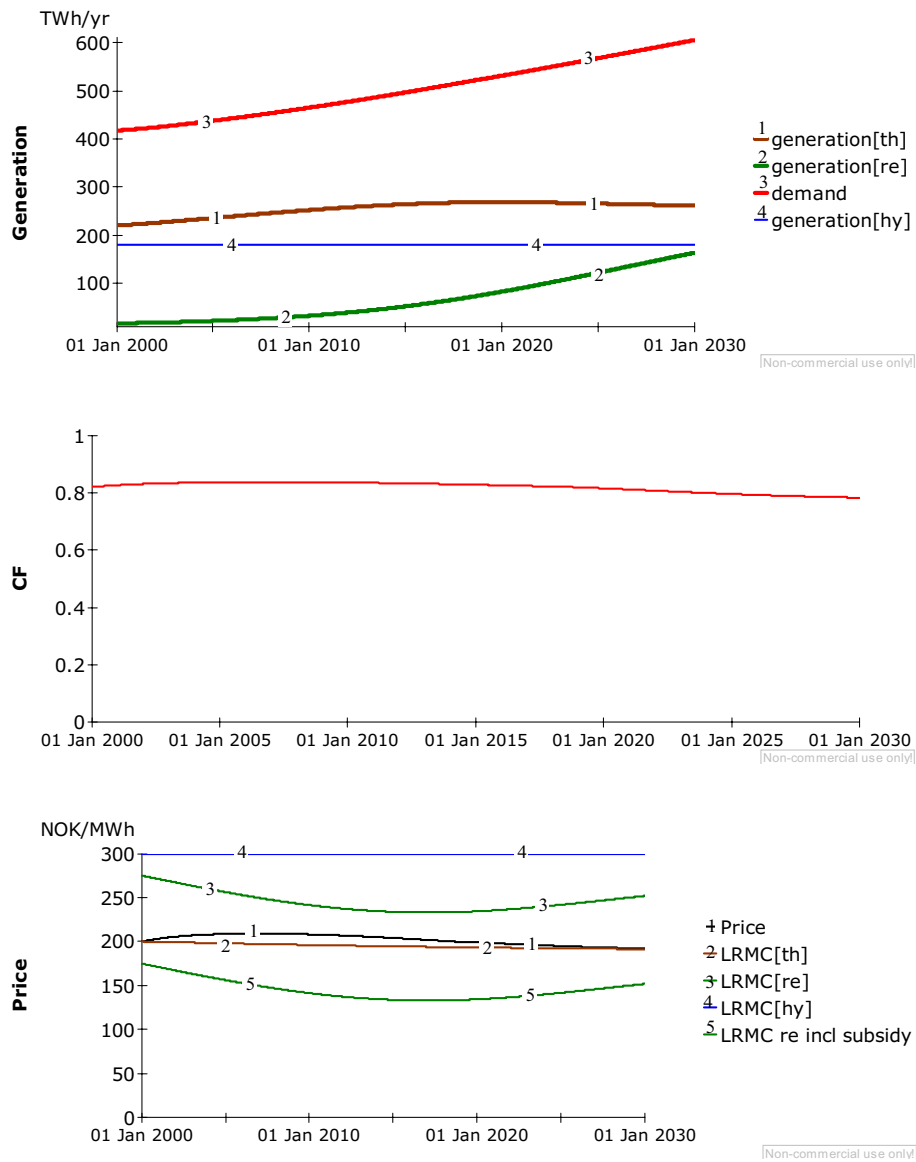
5.9   Sensitivity to resource potential

A more detailed discussion on the resource estimates is provided in *Chapter 12*. A sensitivity analysis will however yield insight as to how important the resource estimate is for the results. Generation is shown with various curves for resource description as depicted in *Figure 5.5*. Generation of resources is most significantly affected while price is not significantly influenced. A doubling of resources (from R_{ref} to R_{200}) would mean 5 year longer delay before renewable generation exceeds thermal.

Figure 5.7 Sensitivity analysis various cost curves of resources R$_{50}$ ... R$_{300}$
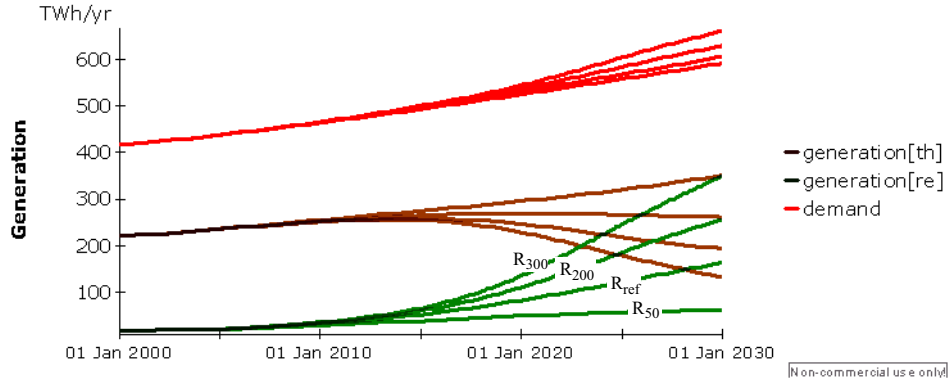
5.10   Sensitivity to technology progress

The only main reinforcing feedback loop identified is the learning curve *(loop R1)* in *Figure 5.1*. Recalling from the theory chapter reinforcing loops are responsible for growth characteristics such as the ones observed in the graphs in the sensitivity analysis of *resource depletion* in *Figure 5.7*. Technological progress constrains technology progress via the long-run marginal costs of investing in new capacity. Relaxing the resource constraint allows technology progress to develop further.

Technology progress is itself afflicted with uncertainty and to analyse the importance of this uncertainty, we perform a Monte-Carlo simulation by varying the learning indexes of thermal and renewable generation. The learning index was defined in *5.37* and is restated here :

5.42 Learning index$_i$ = [0.05 0.2 0]   [1]

for $i \in \{th, re, hy\}$. While technological progress for hydropower is assumed to be neglible being a mature technology with few remaining potential for development thermal and renewables are each assigned *uniformly distributed* learning indexes :

5.43   Learning index$_i$ = [Uniform(0 0.1) Uniform(0.1 0.3) 0]   [1]

where *Uniform(a,b)* denotes a stochastic variable with a uniform distribution between *a* and *b*.

The resulting Monte-Carlos sensitivity analysis was performed with the Reference resource availability R$_{ref}$ and demand and price elasticity of demand as defined in previous sections.

The results in *Figure 5.8* shows in percentiles how the diffusion of renewables are stronger for relatively higher values of learning indexes. Demand is also influenced through price sensitivity. The observed exponential growth of renewables reach the inflection point (at which resource depletion starts to dominate over technology progress) earlier for higher learning rates than for lower. The impact of technological development is however substan-

tial but only after a long period of continued continuous development. From year 2000 to 2010, technology progress hardly make a significant impact on the technology mix in terms of electricity generation. If more resources are available (as in R_{200} and R_{300}) the diffusion of renewables amplifies. Conversely, if resources are less abundant as in scenario R_{50}, technology progress will make a minor impact on the generation mix. In the most extreme case with high learning index of renewables, costs of renewables comes down to 200 NOK/MWh by 2015, but increase thereafter (due to resource depletion).

Figure 5.8 Monte-Carlo sensitivity analysis for development of demand and generation. Learning indexes are uniformly distributed between 0 and 0.1 for thermal technologies and 0.1 and 0.3 for renewables.
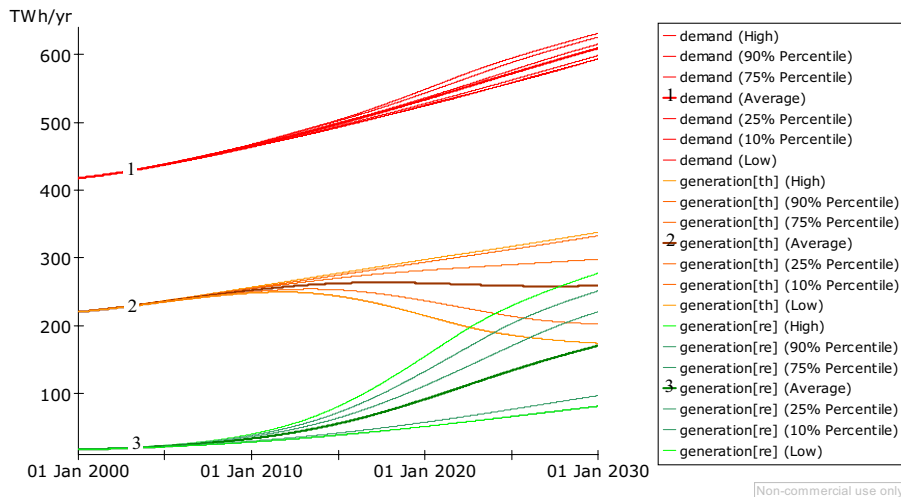
We leave a more detailed discussion of technology progress as well as the underlying theory to *Chapter 11*.

5.11   Exogenous versus endogenous representation of learning

Using the simplified model presented in *Chapter 5* we can analyse the importance of representing learning as dependent on investments (previously installed capacity). Obviously, learning takes place globally outside the boundaries of the local model and cost reductions are to some extent independent of technology policies adopted by the Nordic countries. On the other hand the rationale behind R&D programmes demonstration projects and subsidies of technologies at a national level is to influence the technology development. In *Figure 5.9* and *Figure 5.10* simulation runs are shown where technology progress is modeled as 100 % exogenous (reference case) and as 100 % endogenous. The learning parameters used are summarised in *Table 5.1* and the exogenous learning multiplier is the same as in Eq. 5.37.

R_{ref}

Table 5.1   Exogenous and endogenous learning parameters

	th	re	hy
Exogenous learning rate [1/yr]	0.005	0.014	0
Endogenous learning index [1]	0.05	0.2	0

The first simulation is the same as reference case where subsidies amounts to 100 NOK/ MWh. Simulations runs with exogenous learning rates is shown as the reference in all runs. (thin lines). *Figure 5.9* shows that the difference between exogenous and endogenous representation of technology progress makes some difference towards the end of the simulation period concerning generation whereas price development are fairly similar throughout the simulation.

Figure 5.9 Exogenous (*) versus endogenous technology progress. Subsidy for renewables are 100 NOK/MWh.
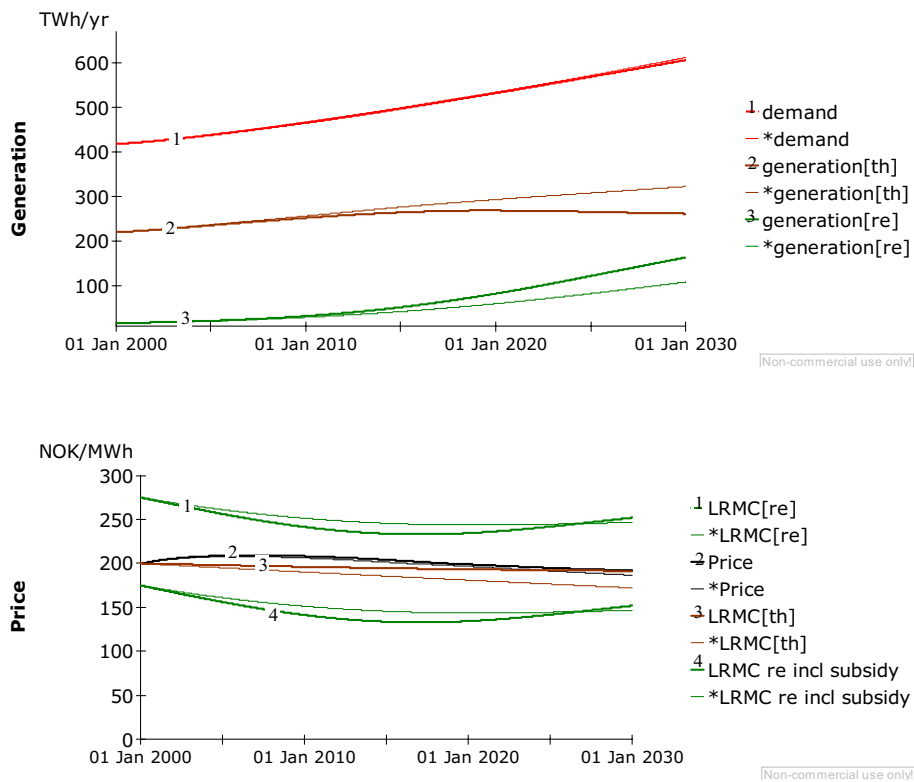
Suppose that wanted to find the impact of increasing subsidies from 100 NOK/MWh to 200 NOK/MWh in 2005. The response of this policy (*Figure 5.10*) shows that renewables will start to dominate over thermal generation halfway in the simulation period whereas an exogenous representation of technology progress shows show a much slower response. The costs are also lowered with an endogenous formulation compared with the exogenous formulation but at the end of the simulation period the resource depletion loop will dominate over technology progress in both cases.

It is not likely that technologies such as nuclear coal and gas - if stimulated in the Nordic countries - will result in significant cost reductions. This is partly due to their maturity secondly there are no manufacturers of these technologies in the Nordic countries (except for smaller gas turbines). It is however likely that using these technologies would result in technology progress in for instance CO2-free technologies (such as CO2-sequestration) devel-

opment of fuel cells or other related technologies - and in such cases a representation of exogenous learning is more appropriate, especially because of the discrepancy between global cumulative installed capacity and locally installed capacity which makes the endogenous learning too optimistic.

Figure 5.10 Exogenous (*) versus endogenous learning when increasing subsidies for renewables from 100 NOK/MWh to 200 NOK/MWh in 2005
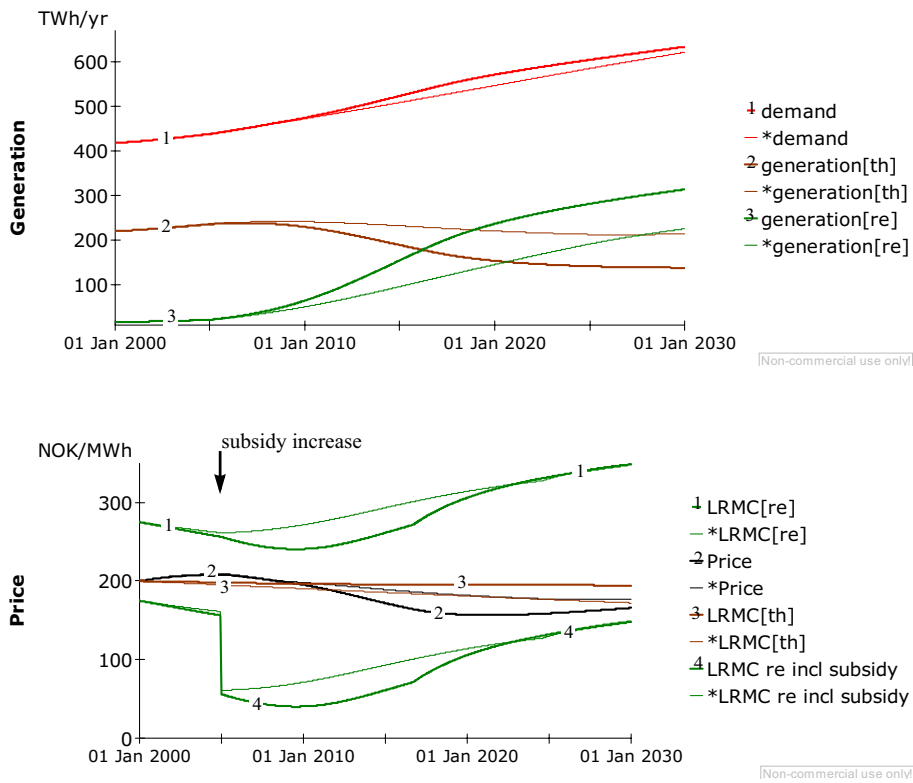
From a policy perspective, the impact of stimulating specific technologies are considerably underestimated if learning is modeled as exogenous. What we can also observe is that the effect of stimulating new technologies does not yield immediate results but will have significant impact in the long term. In many national or regional - even global energy models - technology progress is either not represented or taken as exogenous. If these models are used for decision support on technology or environmental energy policies - the impact of stimulating new technologies are probably severely underestimated and does not appear to have a significant impact.

5.11.1 Aggregated representation

In the previously mentioned models MARKAL and MESSAGE market prices are not given an explicit representation . The projected demand is balanced by generation from installed capacity where capacity is represented by a constant for each technology. This simplification can be justified when studying long-term changes where the operational characteristics

can be represented by averages at least if the system is linear (superposition principle). However, if the system is nonlinear short-term mechanisms can propagate and influence long-term behaviour (Forrester, 1958). In our simplified model we have modeled explicitly operational behaviour of thermal generation through the *Generation scheduling* submodel When subsidised, the share of renewables increase and prices drop and the thermal capacity utilisation drop accordingly.

Figure 5.11 Constant capacity factor versus generation scheduling (production scheduling). *Upper:* **Constant capacity factor CF=0.82.** *Middle:* **Reference case where thermal capacity utilisation is determined by marginal operational costs (generation scheduling loop).** *Lower:* **Capacity factor as a function of market price. Learning index is uniformly distributed between 0-0.1 and 0.1-0.3 for thermal and renewables respectively.**

Figure 5.11 Constant capacity factor versus generation scheduling (production scheduling). *Upper:* **Constant capacity factor CF=0.82.** *Middle:* **Reference case where thermal capacity utilisation is determined by marginal operational costs (generation scheduling loop).** *Lower:* **Capacity factor as a function of market price. Learning index is uniformly distributed between 0-0.1 and 0.1-0.3 for thermal and renewables respectively.**

Do we need to include short-term loops *market dynamics* and *generation scheduling* if we are to study long-term mechanisms such as *technology progress*? A preliminary answer to this is *no* after examining sensitivity analysis in *Figure 5.11* where the upper graph displays distribution of generation subject to uncertain learning rates as in the reference case in section 5.10. The middle graph shows the same sensitivity analysis but where capacity factor CF is now fixed to $CF = 0.82$. The differences in the simulation runs does not seem to be significantly important although we *do* observe a slightly faster diffusion when CF is dependent on operational costs. This is so because a fixed CF will continue to suppress prices since the substitution effect of new renewables is not taken into account. Furthermore low prices reduce price expectations which is the basis for the profitability assessment and thereby investment in new generation. The speed of diffusion of new technologies are then slowed by the lifetime of old capacity. However with the inclusion of the generation scheduling loop capacity factor reduces immediately in response to price reductions. It is here assumed that the supply curve, (short-term marginal costs of thermal generation) does not change over time. In the detailed model, the supply curve is disaggregated onto 5 thermal technologies, each assigned with a supply curve and the distribution of the total aggregated supply curve can therefore change as a consequence of changes in the technology mix (see *Chapter 8*). Furthermore the *erosion of CF* balancing loop (B4 in the causal loop diagram at the start of this chapter) is not included in the simplified model. LRMC is influenced by *resource depletion* and *technology progress* (see Eq sets in *Chapter 5).* In the detailed model however long-run marginal costs for each technology is estimated based on a net present value calculation in which expected capacity utilisation is a component and the impact of reduced capacity utilisation will therefore influence the preferred choice of new investments. These mechanisms will accelerate the diffusion of renewables further so that the impact of explicitly including *electricity*

market and the *generation scheduling* submodels is probably underestimated in this sensitivity analysis.

5.12 Representing vintages

How detailed should *Capacity acquisition* be represented ? Adjustments of the capacity stock involves long time delays hence replacements or transition to new technologies will take a long time. Eq. approximate *Capacity acquisition* as a first-order system where the depreciation rate is proportional to the installed capacity. This means that the distribution of the lifetime of installed capacity is exponentially distributed (i.e. first order response) which is a crude approximation. If we however disaggregate capacity into three vintages with equally long lifetime the distribution of capacity lifetimes becomes more a third order response which resembles more of a lognormal distribution. A more detailed discussion of representing capacity acquisition is provided in *Chapter 10*. For simplicity we represent age distribution capacity as uniformly distributed. Furthermore the characteristic properties of each vintage is not disaggregated that is the CF curve of thermal generation is the same for all three vintages which is the case also for average full load hours. At this stage we want to assess the significance of various alternative model specifications.

The sensitivity to other model parameters can also be assessed. Until now we have looked at increasing the resource base and increasing the learning rate. In this analysis learning rate was chosen to vary.

Figure 5.12 Vintage structure of installed capacity.
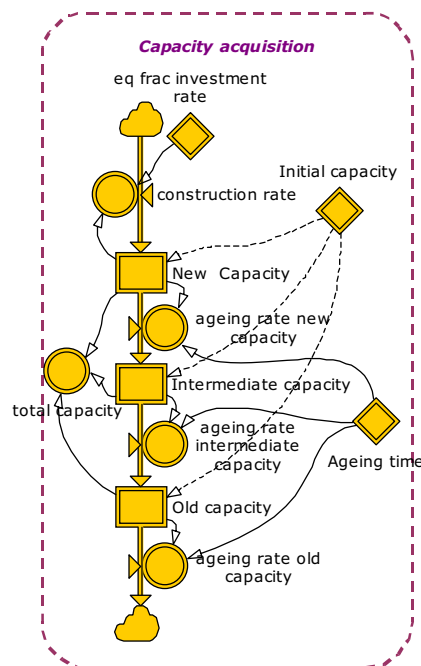
Capacity acquisition submodel

5.44   *New capacity$_{i\,t}$ = New capacity$_{i\,0}$ +* $\int$ *(construction rate$_{i\,t}$-ageing rate new capacity$_{i}$* $_t$)·*dt*   *[MW]*

5.45   *construction rate$_{i\,t}$ = Eq frac investment rate$_i$·profitability multiplier$_i$·New capacity$_i$*
       [MW/yr]

5.46   *Eq frac investment rate$_i$ = [3/30 3/20 3/40]*   *[1/yr]*

5.47   *ageing rate new capacity$_{i\,t}$ = New capacity$_i$ / Ageing time$_i$*   *[MW/yr]*

5.48   *Intermediate capacity$_{i\,t}$ = Intermediate capacity$_{i\,0}$ +* $\int$ *(ageing rate new capacity$_{i\,t}$ -*
       ageing rate intermediate capacity$_{i\,t}$)·dt   *[MW]*

5.49   *ageing rate intermediate capacity$_{i\,t}$ = Intermediate capacity$_i$ /Ageing time$_{i|}$ [MW/yr]*

5.50   *Old capacity$_{i\,t}$ = Old capacity$_{i\,0}$ +* $\int$ *(ageing rate intermediate$_{i\,t}$ - ageing rate old$_{i\,t}$)·dt*
       [MW]

5.51   *ageing rate old$_{i\,t}$ = Old capacity$_i$ / Ageing time$_i$*   *[MW/yr]*

5.52   *Ageing time$_i$ = Lifetime$_i$ /3*   *[yr]*

5.53   *Lifetime$_i$ = [30 20 40]*   *[yr]*

5.54   *Initial capacity$_{i\,0}$ = [37360 5685 41600]*   *[MW]*

5.55   *New capacity$_{i\,0}$ = Initial capacity$_{i\,0}$/3*   *[MW]*

5.56   *Interm capacity$_{i\,0}$ = Initial capacity$_{i\,0}$/3*   *[MW]*

5.57   *Old capacity$_{i\,0}$ = Initial capacity$_{i\,0}$ /3*   *[MW]*

5.58   *total capacity$_i$ = New capacity$_i$+Intermediate capacity$_i$ + Old capacity$_i$*   *[MW]*

Note   *Total capacity is equally distributed on the three vintages as defined in* Eq. 5.55 - Eq.
         5.57 in this example but the vintage distribution can be any.

The results displayed in *Figure 5.13* shows increased sensitivity to technology progress, thus
representing the vintage structure will be important in for the model behaviour.

Figure 5.13 Sensitivity to technology progress with representation of 3 vintages.
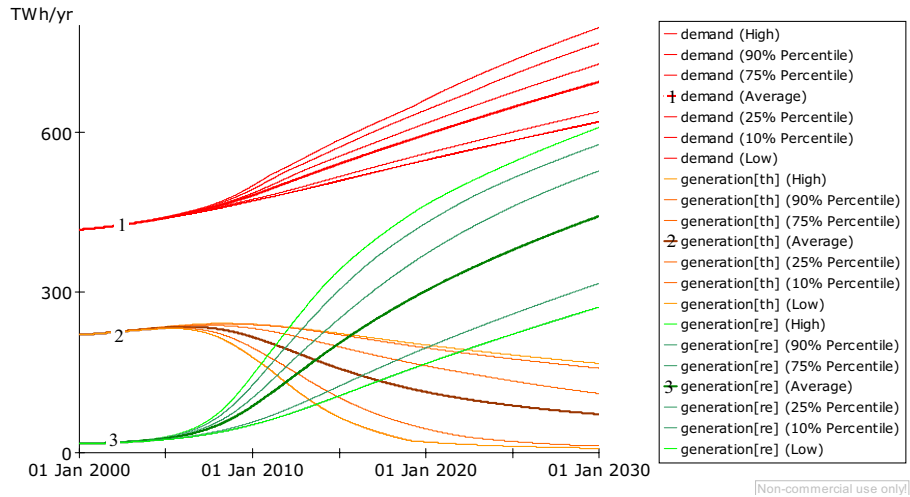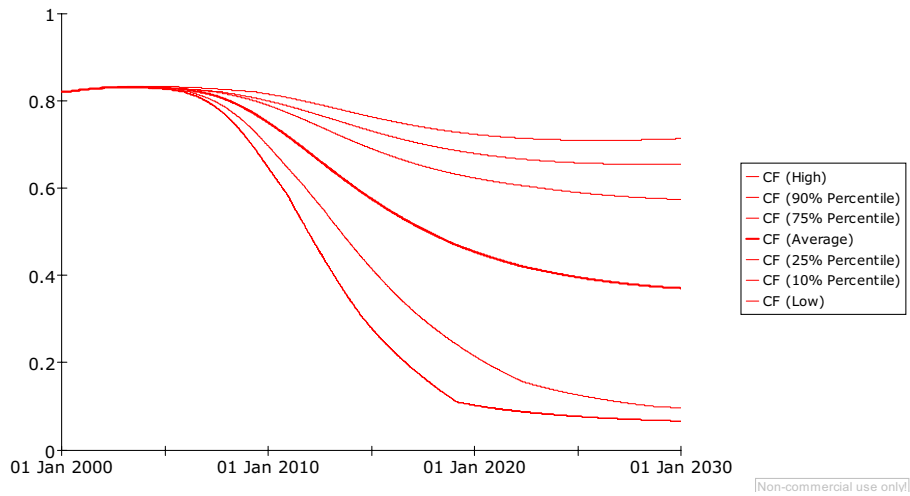
Part II

Kraftsim - a system dynamics model

6   An overview of the Kraftsim model
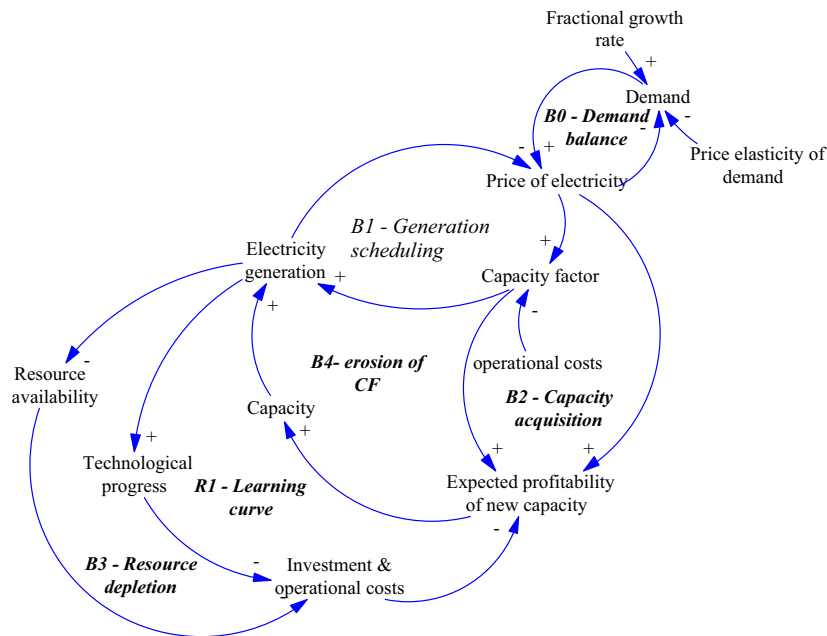
K raftsim's development started by Botterud et al (2000, 2002). Its development continued in Vogstad et al. (2002), Vogstad et al. (2003), and Vogstad (2004), and now more of a modelling concept than a fixed, general model. The original purpose of the model was to represent long-term dynamics not captured by equilibrium models.

From a Norwegian perspective, the model grew to represent the Nord Pool area, and the time resolution was altered from yearly time steps to daily time steps to represent generation scheduling. Furthermore, the model tested various implications of current energy- and environmental policies, pointing out counterproductive consequences and flaws in market designs (*Chapter 15* and *Chapter 16*). In the latter case, a simplified and separate model structure was built and analysed for the Tradable green certificate market. The model was also converted into an experimental economics laboratory (Vogstad et al. 2003, Vogstad 2004), and the model is already in use to test the perfomance of new proposed market designs by Norwegian energy authorities. Simplified parts of the model have been used for teaching purposes at NTNU's Energy and Environmen Programme.

The flexibility and versatility of the model to be tailoded to the specific problem at hand proves to be a major strength of the modeling concept. Changes and new simulations can be performed on the fly during discussion with clients.

Mathematically, Kraftsim is a set of nonlinear differential equations that are solved numerically. System dynamics provides a general theory of how to represent decision rules, organisations, economic and social systems in addition to physical and technical systems can be formulated in a computer model to study the dynamic behaviour. At current, the model contains 150 state variables (stocks), of a nonlinear system. Every single equation of the

model (as of Nov. 2004) is documented in this thesis. This chapter gives an overview of the various sectors of the modelKraftsim submodels.

The chapter page showed the main causal loop diagram that the Kraftsim model is organised around. Each loop was explained in the previous chapter (section 5.1). The main loops were characterised as *Demand balance, generation scheduling, capacity acquisition, learning curve,* and *resource depletion. Figure 6.1* shows the detailed stock & flow diagram, where the dotted rectangles identify the same terms as submodels. Numbers in paranthesis below and on the graph indicate the chapter number where the sector is desribed :

(7) Electricity market price contains a dynamic formulation of price formation in the spot market. An approximate representation of the future/forward price is represented as an adaptiveexponential smoothed forecast of the yearly average price.

Exchange is a submodel that represents available exchange capacity to neighoubring countries outside Nord Poool.

(8) Generation scheduling coordinates the capacity utilisation of each technology type according to price.

(8.4) Generation scheduling hydro represents the particular features of hydropower in scheduling. Hydropower scheduling is based on the water value method.

(8.5) Exchnage represents the aggregate of Nord Pool area's exchange with other countries.

(9) Profitability assessment makes calculations of expected profitability of new investments based on available information about price and costs. The profitability assessment is based on the net present value criterion, using a return on investment index.

(10) Capacity acquisition describes the process of applying for permits, before investing and building new capacity.

(10.1) Application processing The Application process involves significant time delays before permits can be approved.

(10.2) Capacity vintage A vintage structure consisting of three vintages keeps track on the capacity residing in the system.

(10.3) Resource efficiency coflow A coflow keeps track of the age-dependent attribute *efficiency* for each technology and vintage. Efficiency of a plant is important in calculating the operating costs and thereby the the capacity utilisation, plus the estimation of emissions.

(10.3) Technology progress describe the cost reductions that take place as experience cumulates. Technology progress is partly exogenous for investments, and entirely exogenous for improvements in efficiency.

(12) Resource availability keeps track of the remaining available resources for development. Resource availability is also partly exogenous, i.e. no constraints on fossil fuels.

(13) Demand submodel is kept simple as focus is on the supply side. Demand is here represented with a yearly fractional growth, a price elasticity of demand, and seasonal variation. A short-term price elasticity of demand is also incorporated, but will only be important when running simulations at hourly level. .

Figure 6.1 Kraftsim stock & flow diagram
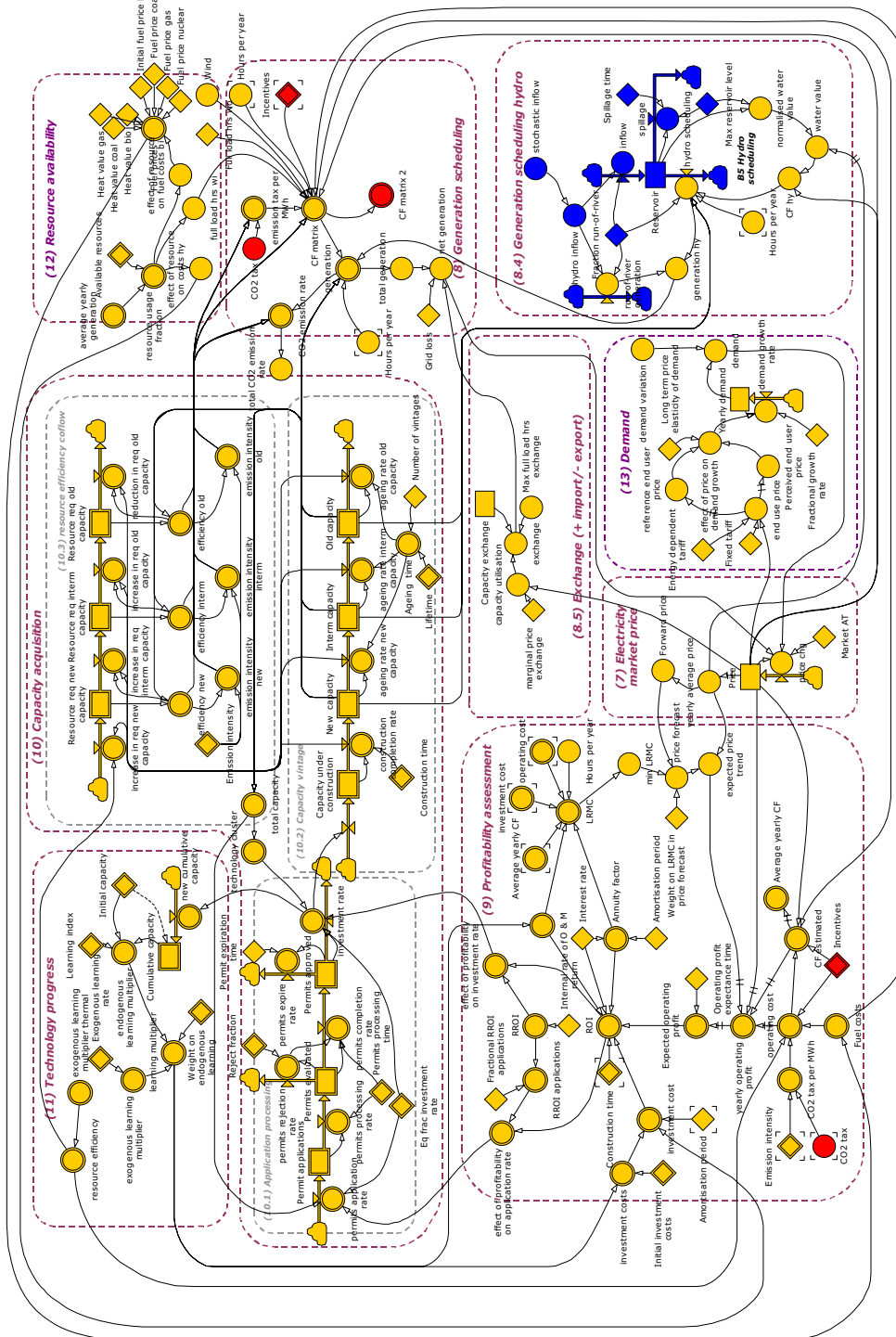
7   Electricity market price
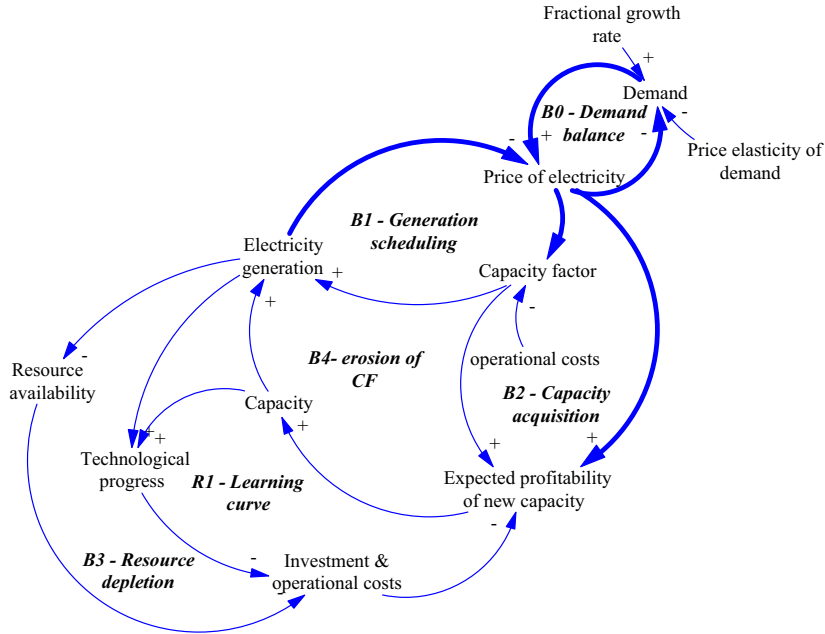
P rice is an important input to all other sectors of the model including *generation sched-uling*, *profitability assessment* and *demand.* Generation scheduling, investment deci-sions and demand are, at least partly, based on price and price expectations. Prior to deregulation, generation scheduling of utilities was based on cost minimisation of each utili-ty's production system. With a transparent spot price, generation scheduling of each unit can be performed as separate optimisation tasks allowing optimisation across utilities' production systems. Under the monopoly regime, a detailed description of each utility's production sys-tem was essential while under the market regime, good models for price prognoses have be-come increasingly more important.

We start by discussing the static formulation of supply and demand and its underlying as-sumptions to contrast it with a dynamic formulation to the price formation process before re-lating this to the Nordic electricity market.

7.1   The price discovery process

Standard economic theory tend to focus on equilibrium and on equilibrium conditions, and the EMPS, NordMod-T and Markal models described in *Chapter 3* is based on a static, inter temporal formulation of the market where supply equals demand, assuming that equi-librium can be reached rapidly.

Suppose that for the electricity market,

$$D_t = f(p_t), S_t = g(p_t) \qquad\qquad\qquad (i)$$

where demand D_t and supply S_t are functions of price p_t at time t, where $f(p_t)$ and $g(p_t)$ represent the behaviour of consumers and producers. The two equations containing three unknowns D_t, S_t and p_t is completed by assuming that

$$S_t = D_t \qquad\qquad (ii)$$

Inspection of Eq. (i) suggests that prices must somehow be known in advance of production or consumption, as there is some time delays involved in both scheduling of production and demand. While a lot of work has been devoted to the derivation of the functions entering Eq. (i), the equilibrium condition of Eq. (ii) is pretty much taken for granted (Arrows, 1975). In order to plan production S_t and demand D_t, we must somehow make expectations about the price. Conversely, to estimate the price we must make expectations about demand and supply. This problem can be solved iteratively as a trial-and-error process according to the law of supply and demand:

$$\frac{dp}{dt} = h \cdot (D(t) - S(t)) \qquad\qquad (iii)$$

where h is a function such that $\frac{dh}{dp} > 0, h(0) = 0$.

The "Law of supply and demand" states that price rises when demand exceeds supply, and falls when supply exceeds demand, which is precisely what Eq. (iii) describes. This formulation is also referred to in literature as the *excess demand* function. In section *4.5.4* of the system dynamics theory chapter, we showed a dynamic formulation of the market that is in accordance with the excess demand function. Furthermore, we showed that the market price formulation in section *4.5.4* can be brought sufficiently close to the equilibrium condition by choosing a sufficiently small adjustment time constant. Thus by replacing Eq. (ii) with Eq. (iii), the price will converge to the same equilibrium price.

7.2   A dynamic formulation of price formation in the Nordic electricity market

To relate this to the spot market, recall *Figure 2.2* in *Chapter 2* which showed the process of bidding price/quantity curves to Nord Pool upon which spot prices were calculated. Although the derivation of spot prices stems from a direct calculation of known demand and supply curves (which conforms to the common representation of price formation using Eq. (i) and Eq. (ii)), the demand and supply curves submitted actually represents *expected* demand/supply curves for the day ahead. Physical generation and consumption takes place well after the spot price has been calculated. The discrepancy, denoted as the excess demand, is adjusted by use of the Real-time market. This discrepancy stems from deviations in the expectations of consumption, and technical failures that can occur on the supply side from the bid were submitted to the time of physical delivery. Imbalance is monitored by system frequency deviations and ACE (Area Control Error), so that designated controllers (such as ACG's[1]) can compensate for deviations.

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1. Area Control Generator

Figure 7.1   A dynamic formulation of price formation in the Nordpool Power Market
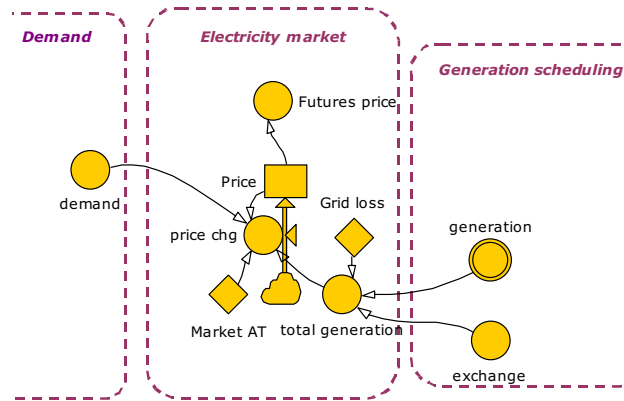
We will here not consider the real-time market explicitly, but give a simplified representation of the spot price as one balancing feedback process in which price adjusts in proportion to the excess demand, over the time interval (Market AT in Eq. 7.3). The bidding process of supply and demand is described in the *Generation scheduling* and the *Demand* submodel. In brief, generation scheduling assumes generators to bid according to marginal operational costs and water values, while the demand side responds by its price elasticity of demand. The dynamic price formulation does, however, not put limitations on the type of bidding strategies represented in generation scheduling.

In the study of the TGC market (*Chapter 16*), we included both *value trading* and *trend following* as bidding strategies. *Figure 7.1* shows the stock and flow diagram corresponding to The Nord Pool spot price formation equation set below.

The Nord Pool spot price formation

7.1 $Price_t = Price_0 + \int price\ change_t \cdot dt$ [NOK/MWh]

7.2 $price\ change_t = Price \cdot (demand - total\ generation)/demand \cdot 1/Market\ AT$ [NOK/MWh/da]

7.3 $Market\ AT = 3$ [da]

7.4 $Price_0 = 150$ [NOK/MWh]

7.5 $Average\ price_t = SLIDINGAVERAGE(Price, 1\ yr)$ [NOK/MWh]

7.6 $Forward\ price_t = FORECAST(Average\ Price, 3\ yr, 4\ yr)$ [NOK/MWh]

The Average price is a sliding average of last years' prices, which is used for display in the simulation graphs, and to remove the seasonal variation in the calculation of the *Futures price*. The forward/futures market contains several contract types ranging from the following week up to four years ahead. We are here concerned with the long-term prices, and therefore represent the long-term four years ahead yearly contracts using the FORECAST function, which is a trend extrapolation of (exponential weighted) prices over a certain period back in time (see Appendix A)

The model can have several interpretations. The first one, is that the Price formation sub-model can be viewed as a hill-climbing search that finds the equilibrium price that sufficiently clears the market (Sterman, 2000). The second interpretation is to consider the price forma-tion submodel as an excess demand function, where the spot price continuously adjust in ac-cordance to the three feedback processes shown in *Figure 2.2* in *Chapter 2*. The second interpretation also means that the equilibrium price over some time interval actually is a sim-plification of the underlying dynamic price discovery process.

Similar dynamic formulations of price can be found in economic literature, where it has been used to study the stability of equilibrium and multiple markets (Samuelson, 1941; Ar-rows and Hurwicz, 1958a,b). Alvarado uses a dynamic price formulation to analyse the sta-bility of power system markets (Alvarado,1999; Alvarado et al. 2000). Similarly, Yu et al. (1999) and Ilic (2000) use a dynamic price formulation to address the dynamics of transmis-sion provision and planning problems in electricity markets, for instance Ilic et al. (1999) ex-plored the possibility of a market for frequency control.

Figure 7.2 Nord Pool spot market prices and Forward contract prices (2 years ahead) from 01/98 to 12/2000. Source: Nord Pool
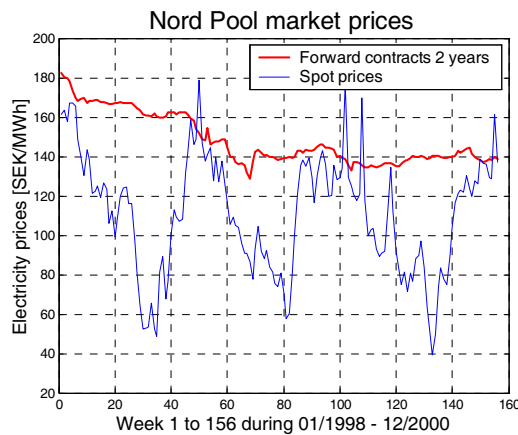
In our model price adjustment time is set to 3 days. The choice of this time constant is a trade-off between the fact that the shortest time interval of interest here is one week, as de-mand, hydro inflow and variation in wind is represented with weekly data, and an adjustment time of 3 days for price was found to give a sufficiently tight match between demand and gen-eration. The numerical time step *dt* is set to a sufficiently small fraction of the smallest time constant in the model (which is the spot market adjustment time) to avoid numerical instabil-ity. A numerical time step *dt* of 1 day was used. If hourly variations are to be represented, say for demand or wind, the adjustment time Eq. 7.3 can easily be modified, as well as *dt*.

7.3   Futures market and price expectations

The concept of rational expectations asserts that outcomes do not differ systematically (i.e., regularly or predictably) from what people expected them to be. This implies that $E[p_t] = p_t$. at some future time point t, on the average. Botterud et al. (2002) analysed the

Nordic spot and futures market, and showed that the one-year ahead futures market ability to predict spot prices are generally low.

There are few other futures markets for electricity to compare against, but one way of measuring its performance in terms of price prediction, is to compare against simple forecasting algorithms, such as adaptive expectations and extrapolation.

A simple form is adaptive expectations where expectations of future prices are based on knowledge of past prices projected into the future; $E[p_t] = f(p_{t-1}, p_{t-2}, ..., p_{t-n})$. A first-order adaptive expectation weighs recent prices exponential (as in Eq. 7.6).

In reality, market participants utilise other information cues than just the price. The reservoir level is particularly an important state variable in the Nordic system. Reservoir levels change slowly, and dry years can influence prices several years into the future. Other market information, for instance expectations about new energy policy implementations such as the CO_2 quota market, or new capacity additions is information that will influence prices in the long term. Such considerations were also claimed among forecasters in Stermans studies on expectation formation in forecasting of energy demand and other markets (Sterman, 1987; 1988; 2000). And yet - a simple adaptive expectations model reproduced their forecasts extremely well by only incorporating past prices as an information cue.

Our model of the futures market should be tested against historical data for Nord Pool. This is however left for future research. The futures market is in our model an indicator for long-term prices that will be used for investment decisions in the *Profitability assessment* submodel in *Chapter 9*.

7.4   References

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8   Generation scheduling
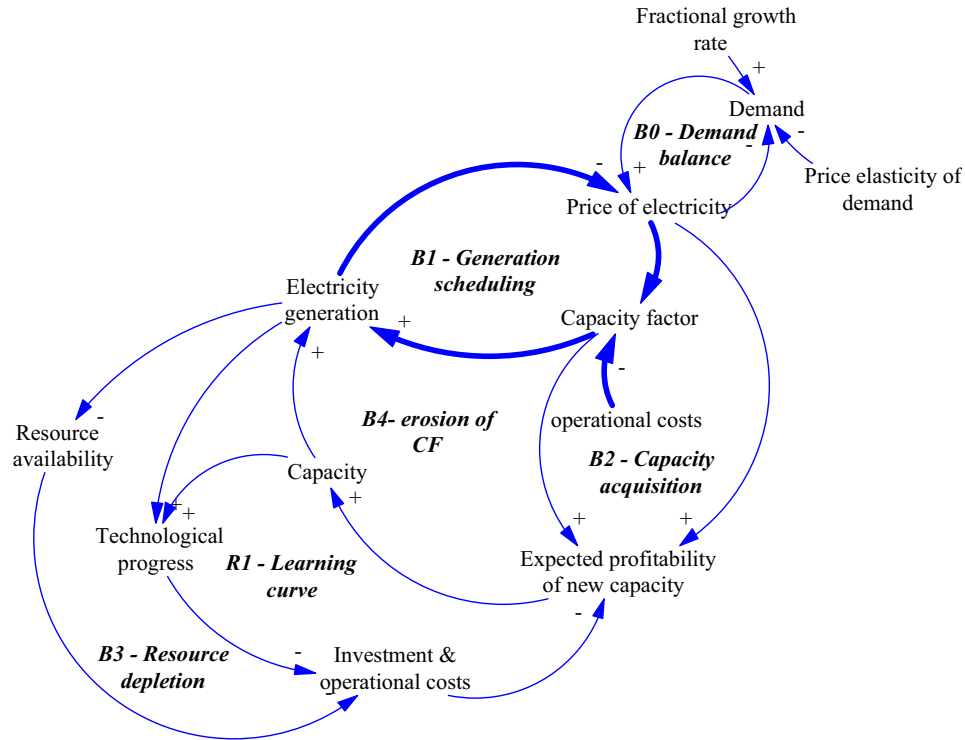
W ith liberalisation, the generation scheduling problem has changed from cost minimisation to profit maximisation for each utility. Prices now coordinate decisions of the individual plants, and hence, generation scheduling can be decentralised. Good price models have become increasingly more important for generation scheduling in addition to risk management facing price uncertainties.

Numerous optimisation models are developed for generation scheduling. For the purpose of our model, we need to include a description of generation scheduling that captures the essential features of each technology with respect to capacity utilisation and emissions. We assume the Nord Pool spot market to be a perfectly competitive market with each utility as price takers.

First, we describe generation scheduling of thermal capacity based on marginal costs. Nex, we describe wind power as an intermittent source in terms of stochastic series of wind converted into electricity generation. The last section provides the system dynamic formulation of the hydro scheduling problem. In *Chapter 17*, we deal with the hydro scheduling problem in details in, developing a SDP[1] model.

8.1   Thermal generation scheduling

In a perfect market, generation is scheduled according to increasing marginal operating costs. Before deregulation, information on fuel costs etc. was readily available. In a com-

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1. Stochastic dynamics programming

petitive environment, information is highly sensitive to competition (Dyner and Larsen, 2001). Moreover, costs vary from plant to plant. Fuel costs in particular are subject to change over the 30 -year time horizon considered, which implies that searching for precise estimates for marginal operating costs is of limited value for a long-term model.

The assumption that companies make bids according to marginal operating costs can also be questioned. In a competitive environment where information about competitors is limited exploratory strategies are probably pursued. Such strategies can be rewarding and result in prices well above those suggested by perfect markets (Bower et al., 1999). In principle, such bidding strategies can be incorporated in the system dynamic modeling framework as evidenced by the TGC model in *Chapter 16*, but the model boundaries would have to be redefined for this purpose.

Figure 8.1 shows the marginal cost curve of thermal units in the Nordic system. This aggregated curve is based on cost estimates of the data set collected for the EMPS simulations (Vogstad et al, 2001); see Appendix B - Data set.

The cumulative capacity utilisation is indicated along the supply curve with circles on the CF curve with corresponding CO_2 emission intensity as triangles.

Figure 8.1   Marginal cost curve thermal generation (left axis). Triangles show emission intensity for the marginal unit in operation (right axis).

a)
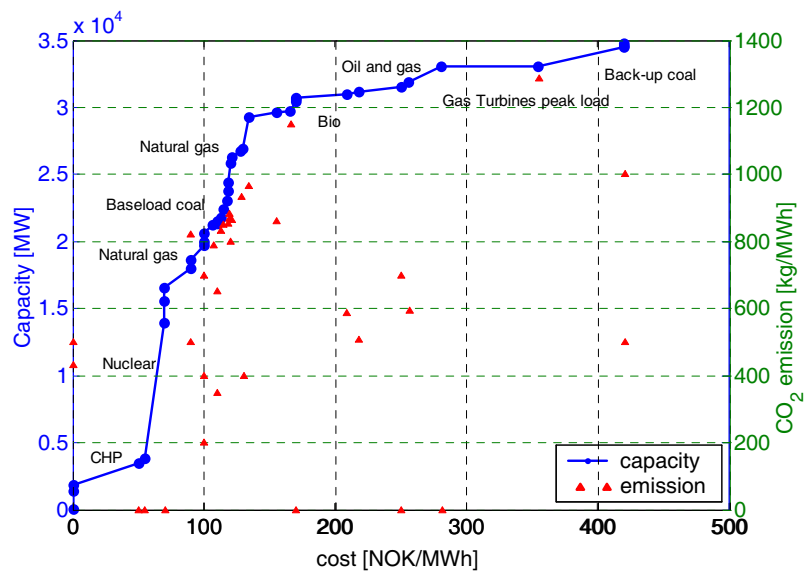
The above curve was used in the simplified model as an approximate description of thermal generation. The shape of the curve resembles a lognormal cumulative distribution.

However, we need to disaggregate the curve into the technologies considered; nuclear, coal, gas, gas peak load and bio if we are to study how investments in new technologies

changes the operations of the market, prices and CO_2 - emissions in response to proposed energy policies.

8.1.1 Supply curve disaggregated on technologies

Figure 8.2 shows the supply curve disaggregated on the various technologies whose capacity utilisation is determined exclusively by the electricity price. These curves were used in a previous version of the system dynamic model, documented in Vogstad et al. (2002) and presented at International system dynamics conference in Palermo, 2002.

Figure 8.2 Marginal cost curves for each technology : CF_i(Price,Intervention$_i$)
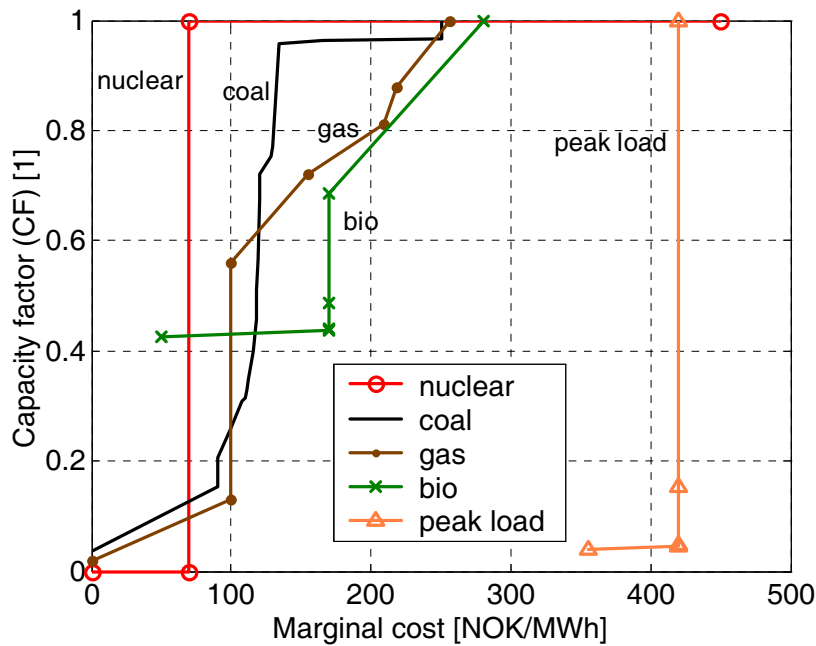
The function CF_i(Price,Intervention$_i$) was however found inconsistent with the replacement of old capacity with new and more efficient units within each technology as the long time horizon allows for substantial technological progress.

8.2 The supply curve disaggregated on technology and vintages

The later development of this model first presented in Vogstad (2004) takes into account the age-dependent attributes of capacity by introducing a vintage structure. In system dynamics, age-dependent attributes - in this case the efficiency of energy conversion - can be taken into account using *Coflow* structures (Sterman, 2000). The capacity utilisation for each technology *i* and vintage *v* can then be defined as:

$$CF_{i,v}(Price, fuel\ cost_i, efficiency_{i,v}, Intervention_i) \qquad \forall\ v, i \in th \qquad (i)$$

where *v={New, Interm, Old}* represents *new*, *intermediate* and *old* vintages, *fuel cost*$_i$ represents the fuel cost of technology *i*, *efficiency*$_{i,v}$ the average energy conversion efficiency of technology *i* in vintage *v*, and *Intervention*$_i$ represents the effect of taxes/ subsidies on technologi *i* per energy unit generated. .

Figure 8.3 Illustration of the supply curve disaggregated on *i technologies* and *v vintages*
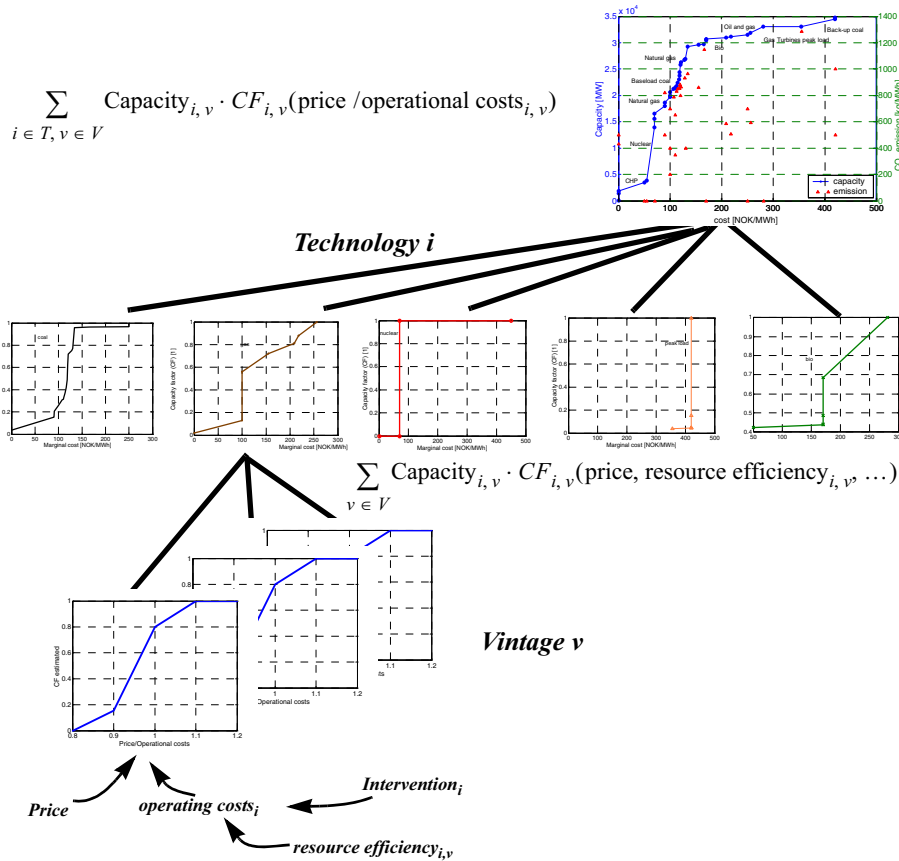
Each technology shown in *Figure 8.2* is split onto the three vintages *New, Interm* and *Old* that possess different *average* resource efficiency.For each technology *i* and vintage *v*, we assume the capacity utilisation $CF_{i,v}$ in Eq. 8.1 to be distributed according to Eq. 8.2-Eq. 8.4

around the price-cost ratio (Eq. 8.5). *Figure 8.4* shows $CF_{i,v}(Price/operating\ costs_i)$, where

Figure 8.4 *CF Table$_{i,v}$* **used in Eq. 8.1 to represent cost distributions. The cost distribution may differ for each technology and vintage.**
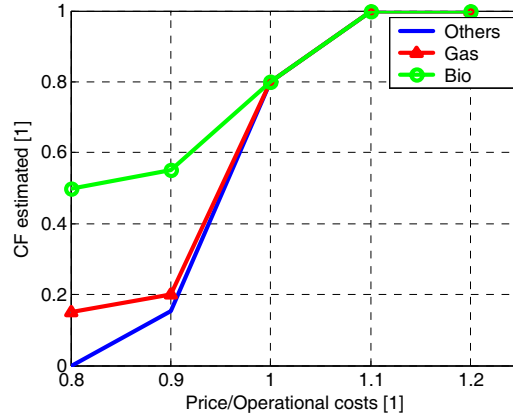
bio and gas has a higher minimum capacity utilisation due to restrictions from serving heat loads and take-or-pay contracts respectively. The $CF_{i,v}$ curves are distributed along the price/ operating costs ratio as shown in *Figure 8.4*. The assumed curves can be changed as better information on operations becomes available. In the assumed CF curves, price/cost ratio of 1.2 will cause full capacity utilisation, while a price/cost ratio of 0.8 will result in a minimum capacity utilisation.

Apparently, the limited number of data within each technology *i* and vintage *v* makes curve estimation difficult. If we are to increase the level of details and complexity of the model, a bottom-up representation such as agent-based models representing each individual plant could be the preferred modeling technique[1].

Generation scheduling submodel $\forall\ i \in$ ***T*** *=\{nu,co,ga,gc,gp,hy,bi,wi,wo\},* $\forall\ v \in$ ***V=\{new,interm,old\}***

8.1 $CF_{i,v} = GRAPH(Price/operating\ costs_{i,v}\ 0.8, 0.1, CF\ Table_{i,v})$ *[1]*

8.2   *CF Table$_{i,v}$ = \{0,0.154,0.8,1,1\}* $\forall\ v, i \in \{nu, co, gp\}$ *[1]*

8.3   *CF Table$_{i,v}$ = \{0,0.154,0.8,1,1\}* $\forall\ v, i \in \{ga, gc\}$ *[1]*

8.4   *CF Table$_{bi,v}$ = \{0,0.154,0.8,1,1\}* $\forall\ v$ *[1]*

8.5   *operating costs$_{i,v}$ = Fuel costs$_i$ / resource efficiency$_{i,v}$ + Intervention$_i$ [NOK/MWh]*

1. System Dynamics and agent based modelling share many underlying assumptions, but while system dynamics takes a more aggregated stance than that of agent based modeling. See Scholl (2001) and Rahmandad (2004) for analyses of the differences and similarities between agent-based modeling and system dynamics.

Figure 8.5 Capacity factor $CF_{i,v}$(Price/operating cost$_{i,v}$)

a) Aggregated Capacity factor
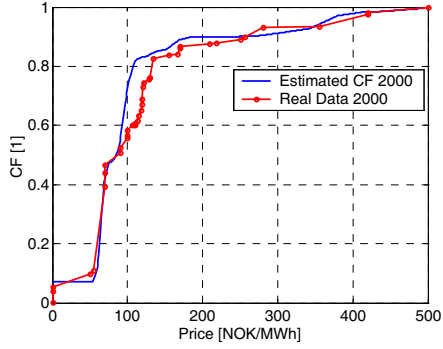
b) Nuclear capacity utilisation $CF_{nu,v}$
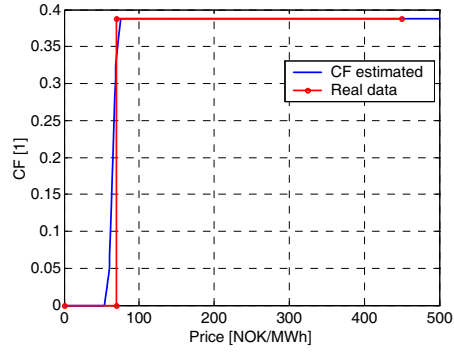
c) Coal capacity utilisation $CF_{co,v}$
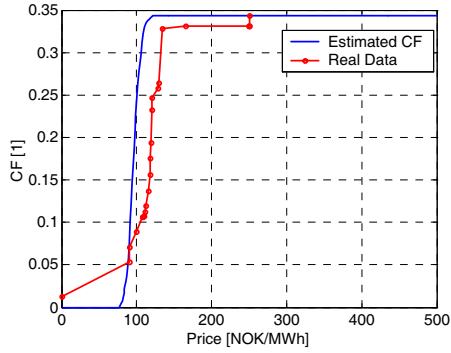
d) Natural gas capacity utilisation $CF_{ga,v}$
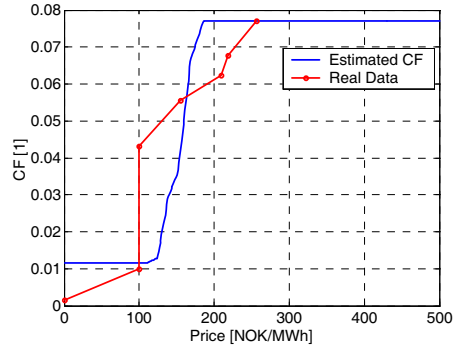
e) Peak load gas capacity utilisation $CF_{gp,v}$
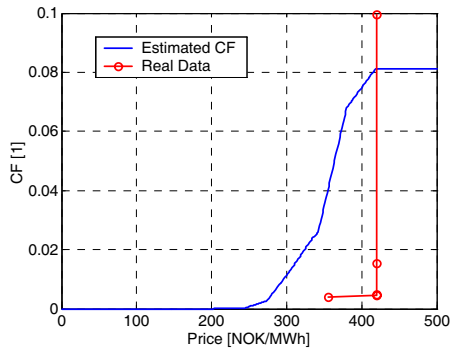
f) Biomass capacity utilisation $CF_{bi,v}$
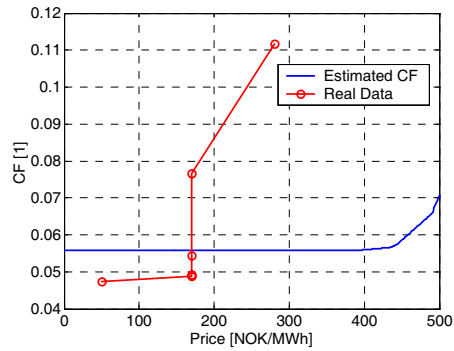
curve $\sum_{i \in T, v \in V} CF_{i,v}$(Price/Operational cost$_{i,v}$) $\cdot$ Capacity$_{i,v}$ in   a)   and

$\sum_{v \in V} CF_{i,v}$(Price/Operational cost$_{i,v}$) $\cdot$ Capacity$_{i,v}$ $\forall i \in th$ for all thermal technologies aggre-

gated over the vintages. The aggregated supply curve matches quite well with the estimated data, while the match is less apparent within each technology.

Equation set (Generation scheduling submodel T ={nu,co,ga,gc,gp,hy,bi,wi,wo}, V={new,interm,old} equation set) represents generation scheduling for the technologies based on feedbacks from various other submodels as illustrated in *Figure 8.6*. Eq. 8.1 does not apply to hydro and wind and their case, capacity factor depends on other factors (Eq. CF-hy,v = GRAPH((Price-water value)/Average Price,0, 10, {0.2 0.214 0.29 0.44 0.69 0.84 0.936 0.98 1 1 1}) ·resource efficiencyhy,v (same as Eq. 8.24) [1] equation set- CFwo,v = normalised windt·resource efficiencywo,v·Full load hrswo/Hours per year [1] equation set) that will be discussed in the remaining sections of this chapter.

8.6 $CF_{hy,v} = GRAPH((Price\text{-}water\ value)/Average\ Price,0,\ 10,\ \{0.2\ 0.214\ 0.29\ 0.44\ 0.69$
$0.84\ 0.936\ 0.98\ 1\ 1\ 1\})\text{·}resource\ efficiency_{hy,v}$ *(same as Eq. 8.24)*   [1]

8.7 $CF_{wi,v} = normalised\ wind_t\text{·}resource\ efficiency_{wi,v}\text{·}Full\ load\ hrs_{wi}/Hours\ per\ year$
          [1]

8.8 $CF_{wo,v} = normalised\ wind_t\text{·}resource\ efficiency_{wo,v}\text{·}Full\ load\ hrs_{wo}/Hours\ per\ year$
          [1]

Net generation refers to the total generation after grid losses are subtracted (Eq. 8.9). Total generation is defined as generation within the Nordic countries, plus exchange with our neighbouring countries (Eq. 8.10) as described in *Chapter 13*.

8.9 $net\ generation = generation\ total\text{·}(1\text{-}Grid\ loss)$ *[TWh/yr]*

8.10 $total\ generation = exchange + \sum_{i\in T,\,v\in V} generation_{i,v}$ *[TWh/yr]*

8.11 $Average\ yearly\ generation_i = SLIDINGAVERAGE(\sum_{v\in V} generation_{i,v},1)$ *[TWh/yr]*

8.12 $generation_{i,v} = Capacity_{i,v}\text{·}CF_{i,v}\text{·}Hours\ per\ year$ *[TWh/yr]*

8.13 $Hours\ per\ year = 8760$ *[hr/yr]*

Taxes on CO_2-emissions and subsidies influence the operating costs each unit, depending on the emission intensity of each technology *i* and vintage *v* (Eq. 8.14).

8.14 $emission\ tax\ per\ MWh_{i,v} = emission\ intensity_{i,v}\text{·}CO_2\ tax$ *[NOK/MWh]*

8.15 $CO_2\ emission\ rate_{i,v} = generation_{i,v}\text{·}emission\ intensity_{i,v}$ *[Mt CO_2 / yr]*

8.16 $total\ CO_2\ emission\ rate = \sum_{i\in T,\,v\in V} CO_2\ emission\ rate_{i,v}$ *[Mt CO_2 /yr]*

8.2.1   The effect of start/stop costs on generation scheduling

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. This will also apply to the operations of the generation technologies.

This is also thoroughly demonstrated in Larsen (1996). In his thesis, a detailed generation scheduling model of Preussenelektra (now a part of E-ON) was used to study the operational implications of power exchange between the Norwegian hydropower system and Germany connected through a transmission line. The generation scheduling model included start-up and shutdown costs for Preussenelektras units. The results showed that exchange with hydropower, will result in a shift towards higher utilisation of baseload (coal) at the expense of medium- and peak load (gas). As a result, emissions increased, and the net exchange between the areas was minor.

Liik et al. (2004) demonstrates that high shares of wind power will alter the optimal dispatch of thermal capacity in a thermal dominated system, leading to reduced efficiency and emission increases by 8-10% .

Forrester discussed the problem of superposition in long-term models with nonlinear effects[1]: *"Models, suitable only for long-range prediction, are often used with short-term influences and fluctuations omitted. This is justifiable only if the system is sufficiently linear to permit superposition, an assumption which has not been justified or defended and which is probable untrue. Therefore, the long-range trends are probably very much a function of the short-range behavior of a system"* (Forrester, 1956).

This model gives a chronological representation of demand load, which makes it possible to include start/stop costs and their impact on the operational characteristics. This has not been implemented yet but the model is designed with such characteristics in this in mind.
.

Figure 8.6 Generation scheduling SFD

a)

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1. First presented as a note to the MIT Faculty Research Seminar 5 Nov 1956, reprinted in System dynamics review (Forrester, 2003)

8.3 Wind as an intermittent source of generation

Wind generation is dictated by the wind and the capacity factor in Eq. 8.7- $CF_{wo,v}$ = normalised $wind_t \cdot$ resource efficiency$_{wo,v} \cdot$ Full load hrs$_{wo}$/Hours per year [1] equation set is represented by the by the *normalised wind$_t$* entering Eq. 8.7- $CF_{wo,v}$ = normalised $wind_t \cdot$ resource efficiency$_{wo,v} \cdot$ Full load hrs$_{wo}$/Hours per year [1] equation set and the normalised resource efficiency of each vintage (see section 10.3 in *Chapter 10*).

Figure 8.7 shows the variation of electricity generation from wind based on Tande and Vogstad (1999) and Vogstad et al (2001). While wind power nicely fits with the seasonal demand profile, most hydro inflow is released during the spring. The data set contains 30 years of wind measurements converted into 52 weeks of wind generation (documented in Tande and Vogstad, 1999) and enter the model as the exogenous variable *normalised wind$_t$* in Eq. 8.7- $CF_{wo,v}$ = normalised $wind_t \cdot$ resource efficiency$_{wo,v} \cdot$ Full load hrs$_{wo}$/Hours per year [1] equation set above. The variable contains a table of weekly or monthly normalised historical wind series corresponding to *Figure 8.7*.

Figure 8.7   Normalised wind series to represent the seasonal and yearly variation of wind as 0,25, 75 and 100% percentiles. Bold lines shows average wind   (Source: Vogstad et al, 2001)

a)
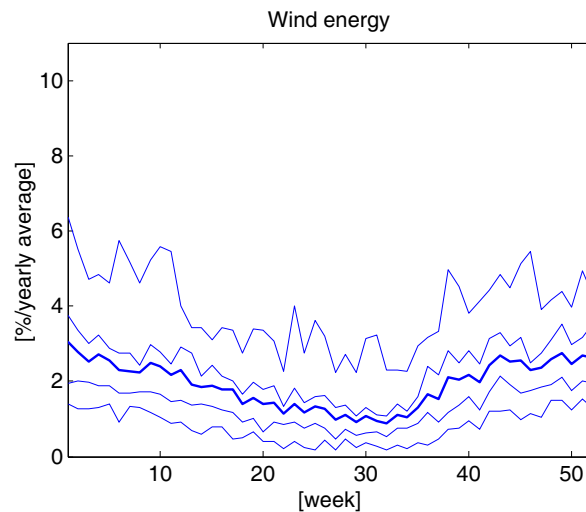
8.4 Hydro scheduling

Hydropower with reservoir poses a more complicated scheduling problem. A water value table, dependent on reservoir level and time of the season determines the capacity factor *$CF_{hy,v}$* for hydro generation entering (Eq. 8.6). Our simplified dynamic representation of hydro

scheduling will be presented here, whereas a complete SDP scheduling model is developed in *Chapter 17*. *Figure 8.8* shows variations of hydro inflow over the season

Figure 8.8 Variation in hydro inflow shown as 0 25 75 and 100% percentiles. Bold line shows average value. (Source: Vogstad et al, 2001)
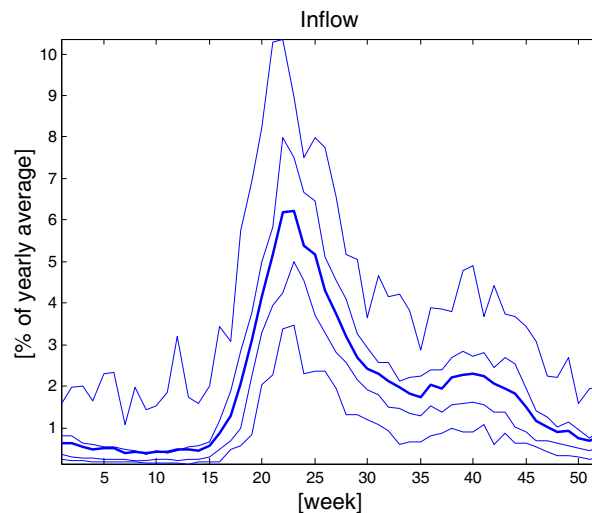
Run-of-river hydropower is similar to the intermittent wind power in the sense that neither of these units is entirely dependent on their intermittent energy source.

The water value 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 the stochastic future hydro inflow, future electricity prices and the present reservoir level. Calculating the expected future profits from storing water is referred to as the *water value method* and utilities use sophisticated optimisation models to accomplish this task (Fosso et al., 1999). The EMPS and the EOPS model described in earlier chapters are dominating planning tools in the Nordic system for hydro generation scheduling.

In *Chapter 17* a simplified model of hydropower scheduling is presented that captures the main features of hydropower scheduling. Combined with our data set for the Nordic market water values are computed consistent with the data set and used as a table lookup function to

represent hydro scheduling. A typical water value table derived from the model developed in *Chapter 17* is shown in *Figure 8.9*.

Figure 8.9 Water value table. Water value is a function of reservoir level and time of the year. The water value table is computed using the SDP model developed in *Chapter 17*.
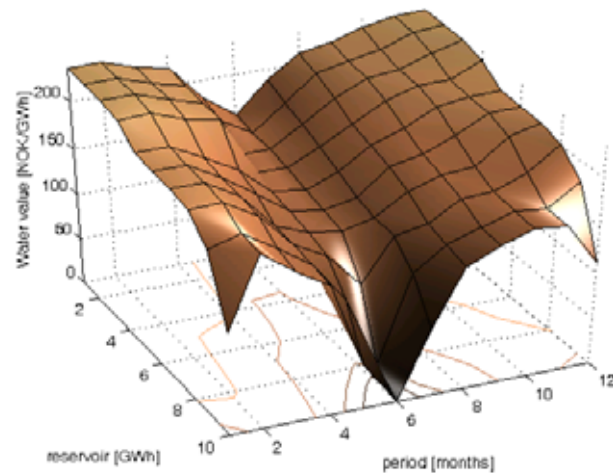
We approximate this hydropower scheduling problem by the stock and flow structure illustrated in *Figure 8.10* with the corresponding equation set:

Figure 8.10 Production scheduling (generation scheduling) for hydropower with reservoirs

a)
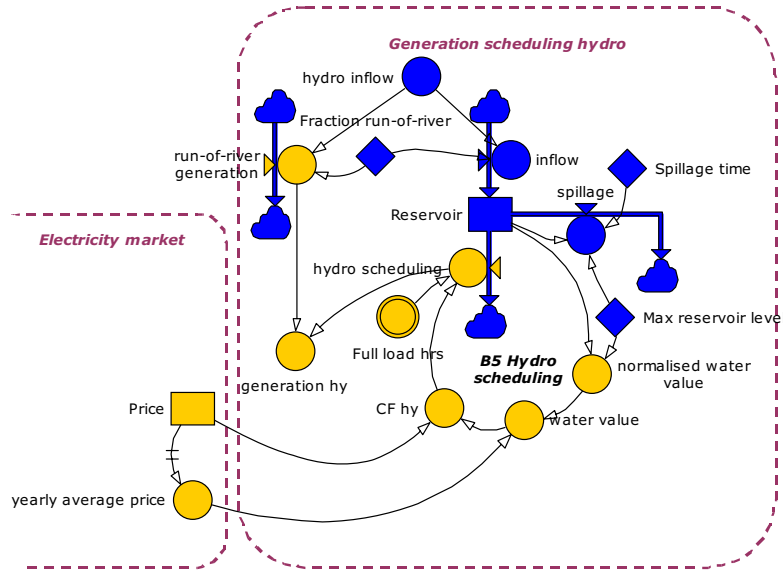
Hydro scheduling submodel

8.17 $Reservoir_t = Reservoir_0 + \int (inflow_t - hydro\ scheduling - spillage_t) \cdot dt$ *[TWh]*

8.18 $Reservoir_0 = Fraction\ initial\ reservoir \cdot Max\ reservoir\ level$ *[TWh]*

8.19 *Fraction initial reservoir = 0.6*   *[1]*

8.20 *Max reservoir level = 123.6*   *[TWh]*

8.21 $inflow = hydro\ inflow_t \cdot (1 - Fraction\ run\text{-}of\text{-}river)$ *[TWh/yr]*

8.22 $hydro\ scheduling_{hy,v} = Capacity_{hy,v} \cdot Hours\ per\ year \cdot CF_{hy,v} \cdot (1 - Fraction\ run\text{-}of\text{-}river)$
     [TWh/yr]

8.23 *Fraction run-of-river = 0.27*   *[1]*

8.24 $CF_{hy,v}$ = *GRAPH((Price-water value)/Price, 0, 10, {0.2 0.214 0.29 0.44 0.69 0.84 0.936 0.98 1 1 1})* $\forall\ v$ *[1]*

8.25 *water value = normalised water value·Futures price*   *[TWh/yr]*

8.26 *normalised water value = GRAPH(Reservoir/Max reservoir level, 0, 0.1 {2.96 2.06 1.63 1.37 1.16 1 0.94 0.77 0.73 0.56 0})*   *[1]*

8.27 $spillage_t = MAX(0,\ Reservoir - Max\ reservoir\ level)/Spillage\ time$ *[TWh/yr]*

8.28 $run\text{-}of\text{-}river\ generation_v = hydro\ inflow_t \cdot Fraction\ run\text{-}of\text{-}river \cdot resource\ efficiency_{hy,v}$
   $\forall\ v$ *[TWh/yr]*

8.29 $generation_{hy,v} = hydro\ scheduling_{hy,v} + run\text{-}of\text{-}river\ generation_v$ *[TWh/yr]*

Hydropower is split into run-of-river and hydro with reservoirs. Run-of-river is simply the stochastic *hydro inflow$_t$* times the fraction run-of-river (Eq. 8.28). The remaining share of inflow enters a reservoir that represents the aggregated reservoir level of hydro generation in the Nordic market (Eq. 8.17.-Eq. 8.21) Hydro scheduling governs the outflow of the reservoir (Eq. 8.22), depending on price and water value (Eq. 8.24-Eq. 8.26)

In wet years, there is a risk of spillage. (Eq. 8.27) where *Spillage time* is the observed interval for which the spillage rate is measured.

8.4.1   Water values in the SD model

Water values are used to compare against current market price how much water to use for electricity generation for the following week. In the long term, water values need to be updated as new information of inflow, fundamental changes in capacity, demand and taxes unfolds. *Figure 8.11* illustrates the main loops governing hydro scheduling.

B5 - reservoir management loop controls the reservoir by computing water values as a function of the reservoir level to be compared with market price (Eq. 8.24), where water values represent the expected future value of storing one additional unit of water (Eq. 8.25 - Eq. 8.26). The tabulated water values representing marginal cost of hydro generation in *Figure 8.9* was computed from the SDP model in *Chapter 17*[1]. The SDP model takes into account the constraints on *max reservoir level*, *stochastic inflow* and the demand and supply curve of

---

1. The tabulated water values here only contains a one-dimensional table of water values against reservoir levels, while the SDP model in *Chapter 17* provide water values as a function of both reservoir level and season. Such a two-dimensional interpolation could not easily be implemented within the Powersim software, but the tabulated data can be linked via an Excel sheet or a Vbscript algorithm. Methodologically and mathematically, however, such an extension does not provide any problems and a two-way interaction between the SDP model in *Chapter 17* and the SD model will be implemented in the near future, allowing water values to be updated when significant changes are in capacity or demand emerge.

other generation including exchange). The loop *B5* has the effect of distributing hydro generation so that the profit is maximised over the year.

Figure 8.11 Main loops governing hydro scheduling
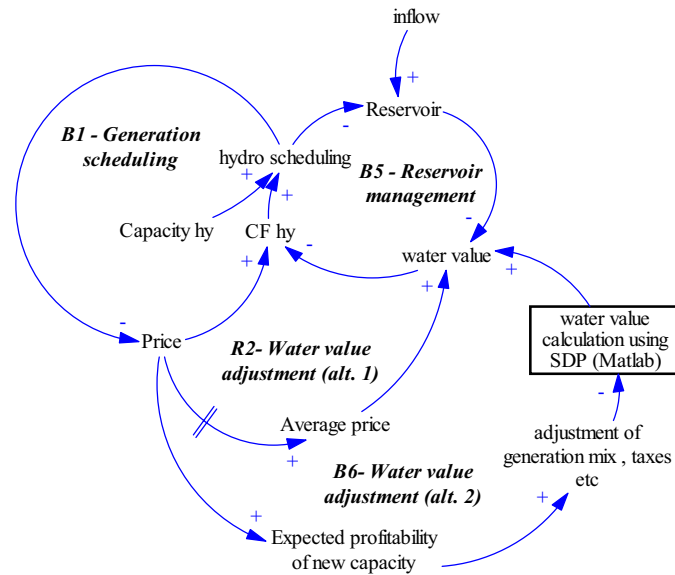
The following paragraphs represent two alternative implementations to the water value calculation. Alternative 1 adjusts the average level of water values in response to average prices (alternatively expected future prices). This alternative provides a simple model implementation and is used in the simulation studies presented here unless otherwise specified. Alternative 2 contains a full-fletched water value computation by linking the SD model to the simplified SDP model presented in *Chapter 17*

R2 - Water value adjustment. **(alt. 1) :** If we consider time scales longer that the seasonal level, the water value adjustment loop (R2) adjust the average level of water values in accordance to the average market price. If a sudden change has occurred that will lead to a change in expectations of long-run future prices - the water value table has to adjust accordingly, otherwise the average reservoir level will deviate optimum. Suppose that a large share of Swedish nuclear capacity is phased out and the expected future prices increase accordingly. If hydro schedulers do not include the change in capacity in their models, water values will be too low compared to the new price level, which causes increased generation that drains the reservoir. In a model spanning over several years, changes in production capacity and other fundamentals that influence the price level must be taken into account. This is done in a simplified way by using normalised water values multiplied with the average/expected spot price (Eq. 8.25). While this formulation adjusts to the correct average price level, the formulation does not account for relative changes in the shape of the water value table from changes of the supply curve.

B6 - Water value adjustment (alt. 2): A consistent representation of water values will be to update the water value table regularly to include new information about supply and demand when it becomes available. Practically, this had to be done outside the Powersim software. Linking Matlab and Powersim has shown to be a feasible way of updating water

values, where water values are calculated in the Matlab environment when changes in fundamentals (capacity, demand, taxes etc.) significantly changes since last water value calculation. Information about demand and the supply curve is then fed in to the Matlab SDP model from Powersim and simulation paused until new water values have been calculated and exported into Powersim. The model can run continuously with this interlinkage, but computation time naturally increases. The dotted-line loop B6 - Water value adjustment (alt 2.) illustrates how changes in fundamentals such as capacity, demand and taxes trigger new water value computations with an externally linked SDP model. operating costs, capacity and demand are variables that can be monitored through a state variable $\mathbf{x}$ = [Capacity$_{i,v}$ operating costs$_{i,v}$ Yearly demand]. If $|\mathbf{x}-\mathbf{x}^*|>\varepsilon$, then the Powersim simulation is paused, and data of the supply curve and demand is passed on to Matlab, which returns a new water value table for the simulation for continued run.

8.5   Exchange

Total transmission capacity for exports amounts to 3500 MW. The profitability of transmission lines depends on the price differences between Nord Pool and neighbouring countries. Deregulation and restructuring of the electricity sector has brought transmission capacity investments to a halt.

One the one hand, if the price difference between Nord Pool and neighbouring countries is high, the transmission itself is profitable, but contributes in reducing each of the exchanging countries' prices. 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. The TSO's on the other hand, are considering new transmission lines based on socio-economic calculations.

In this model, there is no representation of the transmission system, except for this submodel that allows exchange to countries outside Nord Pool. Recent work however, demonstrates the feasibility of representing transmission with a load flow model within a system dynamics model (Dimitrovski et al, 2004) similar the Kraftsim model.

Figure 8.12 Transmission lines from the Nord Pool area to neighbouring countries. Right: Capacity utilisation as a function of the price ratio

a) Capacity exchange SFD diagram
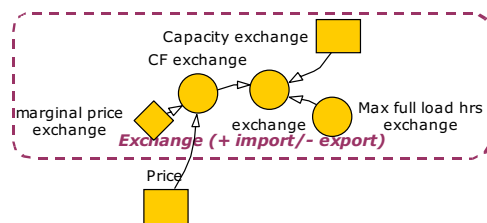
b) Capacity utilisation
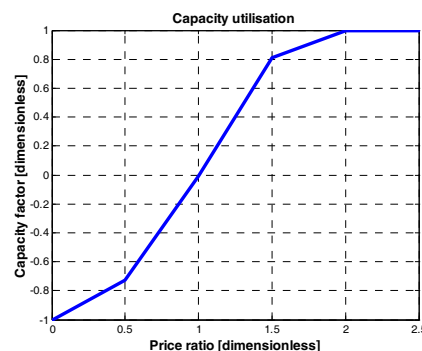
Figure 8.12 shows a) the stock and flow diagram representing exchange between Nord Pool and neighbouring countries. We assume a European price level of 200 NOK/MWh (Eq. 8.30) for exchange. Most important is the daily load patterns between a thermal dominated and a hydropower dominated system.

In thermal systems, the difference between on peak and off-peak prices are larger. Typically, Nord Pool imports during night and exports during day. Larsen (1996) provides a detailed analysis of power exchange between Norway and Germany, using a generation scheduling model. Recently, Asseldonk (2004) performed a similar analysis of the NorNed transmission line to the Netherlands.

Hourly simulations are not parts of the results in this thesis, although the model is designed run hourly simulations.

Exchange submodel

8.30   *exchange = Capacity exchange·CF exchange·Max full load hrs exchange [TWh/yr]*

8.31   *Capacity exchange = 3500*   *[MW]*

8.32   *Max full load hrs exchange = 8000*   *[hr/yr]*

8.33   *CF exchange=GRAPH(Price/'marginal price exchange',0,0.5,{-1,-0.73,-0.01,0.81,1, 1}*   *[1]*

8.34   *Marginal price exchange = 200*   *[NOK/MWh]*

8.35   *emission intensity from exchange = emission intensity$_{co,old}$*   *[Mtonne/yr]*

Investment in new capacity is not taken into account here, and the transmission model needs to be developed further. Imports are defined as positive excexchangehange, exports as negative exchange. In *Chapter 15*, we analyse the impacts on CO2 of building gas power in the Nord Pool area. The simulations also account for CO2 from exchange, in which case we assumed generation from Germany to have the same emission intensity as the oldest vintage of coal in the Nord Pool area (Eq. 8.35).

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9   Profitability assessment
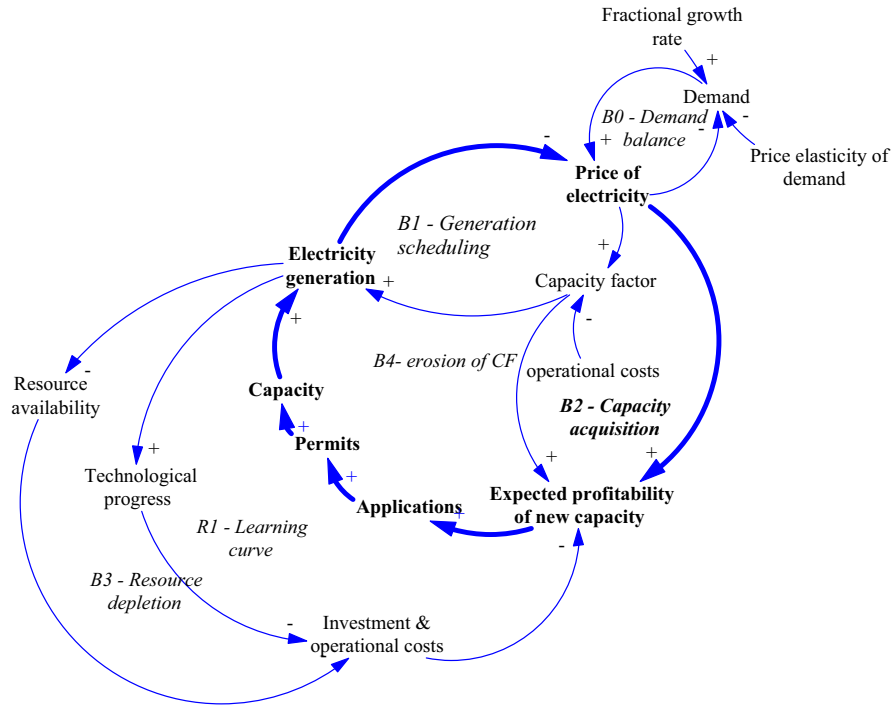
P rofit expectations govern investments in new capacity. Profit expectations are in turn based on expectations of future prices and market conditions. Acquisition of new capacity involves long time delays, facing substantial elements of financial risk.

Profitability assessment is a part of the *Capacity acquisition loop B2*, which adjusts the stock of capacity in response to long-term price changes and cost developments. Investment behaviour is therefore a key explanatory factor in the long-term analysis of the Nordic electricity market.

In section 9.1, we discuss representation of investments from literature and previous modelling work. Section 9.3 presents the investment rate in our model, which uses the profitability indicator presented in section 9.2.

The expected profitability indicator calculates return on investments based on marginal costs, tax/subsidy incentives and long-term price expectations, each of which in turn is influenced by feedback from the other sectors of the model.

9.1   Modelling investments

As a perfect foresight model, Markal presents an optimal investment path subject to constraints on maximum investment rates over a specified time horizon. In doing so, the model provides a rationale for the energy planner on how to allocate investments for the future; however, there are no single decision makers in a liberalised market.

In NordMod-T (Johnsen, 1998), new capacity is added at the start of every year. The level of investment equals the additional capacity needed to bring the *electricity price* in year *t* in equilibrium with the *long-run-marginal costs*. With only one year time lag, the model does

not account for the long time delays involved in capacity acquisition under the assumption that investors are able to plan the investment well in advance. With this assumption, the model stays close to the social welfare optimum, unless severe constraints on capacity are superimposed.

The IDEAS model that was used to analyse the US energy sector, based new investments on the following logic: Use demand projections to estimate required investments, next allocate these to the different available technologies using the *logit model:*

$$share_i = \frac{\cos t_i^{-\lambda}}{\sum_j \cos t_j^{-\lambda}} \qquad (i)$$

where *share*$_i$ represents the fractional share of technology *i*; *cost*$_i$ is the energy cost of technology *i*, $i, j = 1...N$ technologies and λ is a parameter describing the cost distribution. *Eurogas* (Moxnes, 1986) and the *Timer* model (de Vries, 2001) apply similar logic. The former describes oil, gas coal and electricity demand in Europe and the latter is a global energy model developed at RIVM[1].

Econometric studies shows that investment functions based on expected optimal return of investments gives the best fit to historical data, both for individual firms and industry groups (Jorgenson, 1971).

Ford (1999, 2001) represents investors in the Californian electricity market by three different types: Believers, pre counters and followers. Knowing demand growth, depreciation and capacity, investors are able to estimate reserve margins and thereby prices. Believers count installed capacity, pre counters additionally account for capacity under construction, whereas followers only invest if other market participants choose to do so.

Bunn and Larsen (1992, 1994) make similar detailed assumptions on profitability calculations, on a specific problem of capacity payments as incentive for investments in new capacity.

Keynes (1936) argued that profit expectations, and the degree of confidence or weight that managers place in their profit forecasts, determine investment. Keynes stresses the fact that decisions must be based on *expectations*, which in this case is the expected return on investments for new capacity. Keynes asserts that *perceived risk* affect the size of the investment. The perceived risk arises from the investors' confidence in his prospective yield.

Anderson and Goldsmith (1997) tested Keynes hypothesis against panel data from managers, and concluded that investment rises both when they are more optimistic (expect higher profitability), and when they exhibit greater confidence in their forecast. Low confidence in future expectations results in a precautious attitude towards new investments.

Pindyck (1991) points out that the *quality* of information may dictate the pace of investments. By delaying investments, more confidence can be gained as new information arrives. Investment decisions can then be rephrased from *"now or never"* to *"now or later"*.

Botterud (2003) developed models for analysis of long-term investments in liberalised electricity markets. Using SDP and real options theory, uncertainties are handled to find the optimal timing of investments.

9.2   Profitability assessment

The purpose of the profitability assessment model is not to find an optimal or perfect investment criterion, but to represent *investment behaviour* and their decision rules. The pur-

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pose of the Kraftsim model is to study the system behaviour that arises from these decision rules, not for supporting single investment decisions. With this in mind, we must captureing the essentials of investment decisions in the electricity market. As an aggregated model, we also need to represent the aggregate investment rate.

To estimate profitability, investors must take into account the price distribution when making their investments, in particular, the profitability of peak load capacity is sensitive to price distribution. Investors will typically try to estimate price distributions from time series, or using fundamental models such as the EMPS model. The forward market provide prices up to four years ahead, which can be used for price prognosis.

For investments, utilities must consider time horizons beyond the forward market, with economic payback periods of 10 to 15 years.

We try capture both these aspects in the profitability assessment model presented in the next section. *Figure 9.1* shows the SFD diagram corresponding to the *Profitability assess-*

Figure 9.1 Profitability assessment submodel SFD diagram
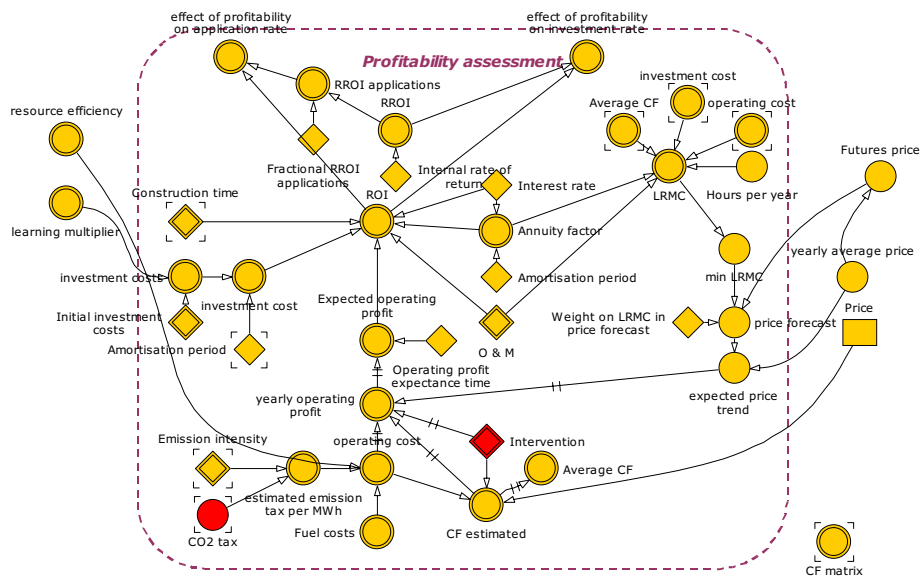
ment submodel. Eq. 9.1 through 9.35

9.2.1   Future price expectations

Perhaps the most crucial factor in profitability assessment is expectations of future market prices. The Nord Pool forward market provides an indicator for prices up to four years, and more importantly enable the possibility to hedge risk.

Investment must, however consider time horizons longer than four years. Three to four years ahead, fundamentals such as new capacity or demand are not likely to change (except for hydro inflow). The current state of the reservoirs can influence prices several years into the future.

In the longer term, however - new capacity and development on the demand side, as well as new environmental regulations or market regulations can change prices significantly.

These factors must be brought into consideration when investing as the forward market does not price in such long-term expectations.

The long-run marginal costs of each technology, which is subject to changes in fuel prices, technology progress and resource availability change slowly. A perfect market will tend to converge towards long-term equilibrium, and so the long-run price in the market should converge towards the most competitive technology, which (at present) appears to be combined cycle gas power. Naturkraft (2003) held this view at a seminar organised by Montel[1].

Thus, long-term prices should converge towards 250-300 NOK/MWh - the price of new gas plants depending on the required return on investments of utilities and plus the gas price, which is exogenous to our model.

Assuming investors pay attention to both the forward market, and long-run marginal costs of technologies (possibly from model simulations[2]) as a basis for price expectations. In Eq. 9.1, *Price forecast* is a weighted average of *forward prices* and the most competitive technology, taken as the minimum of $LRMC_i$ (Eq. 9.2) of the nine technologies *i* considered. The weight factor (Eq. 9.3) states how much investor emphasise the forward market versus the long-run marginal costs in their expectation formation.

Price forecast

9.1   *Price forecast = Forward price·(1-Weight on LRMC in price forecast)+MIN(LRMC_i)·Weight on LRMC in price forecast*   *[NOK/MWh]*

9.2   *$LRMC_i$ = energy investment cost_i·Annuity factor_i+operating costs_i+O&M_i*   *[NOK/MWh]*

9.3   *Weight on LRMC in price forecast = 0.25*   *[1]*

9.2.2   Return on investments, ROI

The first version of the profitability assessment submodel was developed and implemented by Botterud et al. (2001)[3] in his Kraftsim model. Later versions of the model incorporated changes, from Vogstad et al. (2002) to Vogstad (2004). Utilities invest when the *expected* present value of a project is positive, that is:

$$\Pi_i = \pi_i(t) - IC_i = \int_0^{T_{a,i}} (\pi_i(t) - O\&M) \cdot e^{-r(t+T_{c,i})} dt - IC_i > 0 \qquad (ii)$$

where $\pi_i(t)$ is the expected yearly operating profits in [NOK/MW/yr], IC_i the investment costs at time *t*, O&M is the operation and maintenance costs independent of the capacity utilisation, *r* is interest rate, $T_{c,i}$ and $T_{a,i}$ is the *construction time* and *amortisation time*, respectively.

At break even, operating profits equal investment costs:

$$\Pi_i(t) = \int_0^{T_{a,i}} ((\pi_i(t) - O\&M) \cdot e^{-r(t+T_{c,i})} dt) = IC_i \qquad (iii)$$

Furthermore, we simplify into:

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1. Montel, a magazine for the electricity business, www.montel.no
2. Nordmod-T, (NOU, 1998) provide such scenarios for long-term price development
3. Available in Appendix E.

$$\Pi_i(t) = (\pi_i(t) - \text{O\&M}) \cdot \int_0^{T_{a,i}} e^{-r(t + T_{c,i})} dt = IC_i \qquad (iv)$$

Solution of the integral gives:

$$-\frac{1}{r}(e^{-r \cdot (T_a + T_c)} - e^{-r \cdot T_c}) \qquad (v)$$

Inserting Eq. (v) into Eq. (v) and then divide by the annuity factor $a = \dfrac{1 - e^{-r \cdot T_a}}{r}$, we can re-arrange Eq. (v) into the *return on investments ROI_i*:

$$ROI_i = \frac{(\pi_i(t) - \text{O\&M}) \cdot e^{-rT_c} \cdot a}{IC_i} = 1 \qquad (vi)$$

Expected *operating profits*, $\pi_i(t)$ has not been defined yet.

Operating profits$_i$ $\pi_i(t)$ depend on the difference between *price* and *operating costs* and capacity utilisation, $CF_{i,new}$. Since we do not prices or price distributions, we make some expectations about future profits based on experience. We calculate the recent years operating profits over the period $T = 1$ yr for technology *i as*:

$$\pi_i(t) = \int_{t-T}^{t} \left((\text{Price} - \text{operating cost}_i) \cdot CF_{i,new}\left(\frac{\text{Price}}{\text{operating cost}_i}\right) \right) \cdot dt \quad \forall i \qquad (vii)$$

$CF_{i,new}$ range between 0 and 1 depending on the whether the price is above or below operating costs. *Figure 9.2* demonstrates the operating profits over the one-year interval T.

Figure 9.2 *Operating profits* is the moving window of recent year's profit per energy unit expressed in [NOK/(kW·yr)].
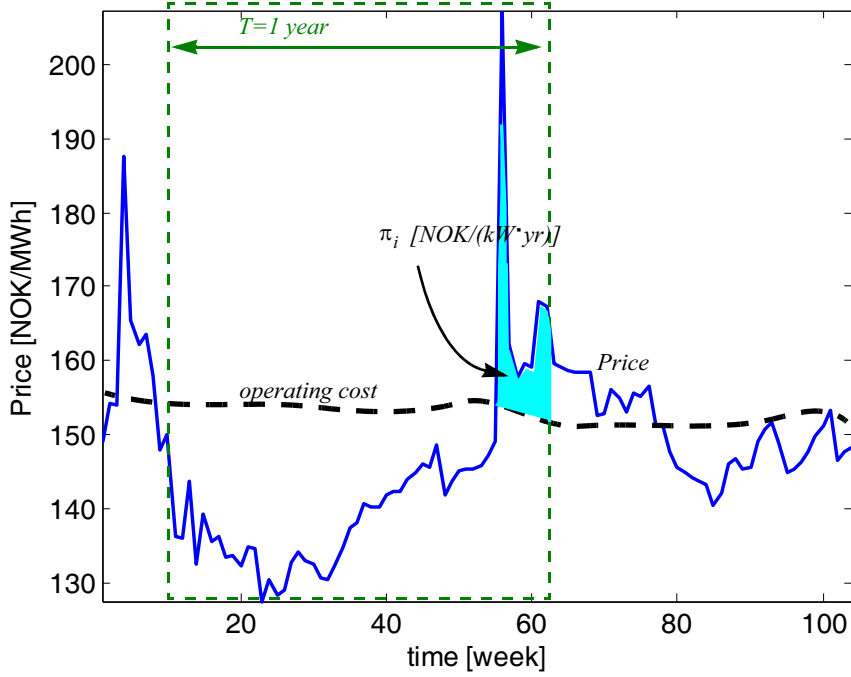
In the model, operating profits are updated by the simulation running in continuous time. Operating profits capture the price distribution within a year, depending on the resolution of the simulation. Variations from year to year are not included. If hourly load patterns are included, the profit calculation will also contain the resulting price distribution. *Figure 9.2* shows weekly spot prices at Nord Pool.

Furthermore, we can adjust expected operating profits by using year'sour *price forecast*:

$$\pi_{i(t)} = \int_{t-T}^{t} \left(\left(\text{Price}_t \cdot \frac{\text{Price forecast}_t}{\text{Average price}_t} - \text{operating cost}_i \right) \cdot CF_{i,new}\left(\frac{\text{Price}}{\text{operating cost}_i} \right) \right) \cdot dt \quad \forall i \quad (viii)$$

Rather than only relying on the recent year, we can take into account previous year's by exponentially averaging $\bar{\pi}_i$ of yearly operating profits π_i:

$$\bar{\pi}_i(t) = \bar{\pi}_i(0) + \int_0^t (\pi_i(t) - \bar{\pi}_i(t)) \cdot \frac{1}{T_s} dt \qquad (ix)$$

where T_s is the smoothing time.

Using $\bar{\pi}_i(t)$ as an estimate of future *operating profit$_i$*, ROI_i can be rewritten to:

$$ROI_i = \frac{(\bar{\pi}_i(t) - O\&M) \cdot e^{-rT_c}}{a \cdot IC_i} \qquad (x)$$

Hence, Eq. (x) yields the expected return on investments taking into account the price distribution and price expectations.

The return on investment formulation here incorporates price distribution and price expectations. The price distribution is endogenously calculated from previous year's data. Normally, price distributions are computed from outside the model. This formulation does however not include variations in hydro inflow based on historical data. Price distributions from hydro inflow scenarios can be derived from the EMPS model. Our SDP model in *Chapter 17* can in principle generate such scenarios consistent with data from this model when updating water values, but this feature has not been implemented yet.

. The below *submodel Return on investments* restates the *ROI* model formulation outlined in Eq. (ii) - (x). Eq. 9.4 corresponds to Eq. (x), Eq. 9.5- 9.7 to (viii) and (x).

Return on Investment (ROI) $\forall\ i \in$ ***T:***

9.4   *ROI_i = discount factor from construction delay·(expected operating profit$_i$ - $O\&M_i$)/ (Investment cost$_i$·annuity factor)*   *[1]*

9.5   *Expected operating profit$_i$ = DELAYINF(yearly operating profit$_i$, T_s) [NOK/MW/yr]*

9.6   *T_s = 3 //smoothing time*   *[yr]*

9.7   *yearly operating profit$_i$ = SLIDINGINTEGRATE(price·(price forecast/Yearly average price)-operating cost$_i$)·estimated CF$_i$, 1)*   *[NOK/MW/yr]*

9.8   *operating costs$_i$ = fuel cost$_i$/resource efficiency$_i$-Incentives$_i$+CO2 tax per MWh$_i$ [NOK/MWh]*

9.9   *fuel cost$_i$ = fuel price$_i$*   *[NOK/MWh]*

9.10   *Incentives$_i$ = [0 0 0 100 0 0 100 100 100]*   *[NOK/MWh]*

9.11   *O&M = [162 40 37 40 25 0 40 162 226.8]*   *[NOK/MW/yr]*

9.12   *discount factor from construction delay$_i$ = exp(-interest rate·Construction time$_i$) [1]*

9.13   *annuity factor$_i$ = (1-exp(-interest rate·T_a))/interest rate*   *[1]*

9.14   *Investment cost$_i$ = Initial investment cost$_i$·learning multiplier$_i$ $\forall\ i \neq hy$*   *[NOK/kW]*

9.15   *Initial investment cost$_i$ = [22.5 11 5.5 10.45 4 0 10 6.5 8.45]$\forall\ i \neq hy$*   *[NOK/kW]*

9.16   *Investment cost$_{hy}$ = effect of resource on costs hy*   *[NOK/MWh]*

The CO2 tax depends on the type of fuel and conversion efficiency for each plant:

9.17   *CO2 tax per MWh = Emission intensity /efficiency$_i$·CO2 tax $\forall\ i \in$ {co,ga,gc,gp}*   *[NOK/MWh]*

9.18   *Emission intensity$_i$ = [0,0.3,0.2,0.02,0.25,0,0,0,0]*   *[kg CO2/kWh]*

9.2.3   Long run marginal costs LRMC

Long run marginal costs *LRMC* can be calculated as follows:

Long run marginal costs (LRMC) $\forall\ i \in$ ***T:***

9.19   *$LRMC_i$ = (Investment cost$_i$·annuity factor+$O\&M_i$)/(Hours per year·Average yearly CF$_i$)+ operating cost$_i$$\forall\ i \neq hy$ [NOK/MWh]*

9.20   *$LRMC_{hy}$ = Investment cost$_{hy}$ + $O\&M_{hy}$*   *[NOK/MWh]*

Table 9.1 summarise the parameters used. In Eq. 9.8, operating costs are *Fuel costs$_i$*

Table 9.1   Initial values for profitability assessment

		thermal					renewables			
		nu	co	ga	gc	gp	hy	bi	wi	wo
Investment costs [kNOK/kW]	x	22.5	11	5.5	10.5	4	see section 12.2	14.5	8.1	11.3
Lifetime [yr]		40	30	30	30	30	40	30	20	20
Full load hrs [hr/yr]	x	8760	8760	8760	8760	8760	4800	8760	2500	3500
Capacity factor [1]	x	price	price	price	price	price	water-value	price	wind	wind
Resource efficiency[1] [1]		0.35	0.45	0.58	0.45	0.35	1	0.33	1	1
Fuel price in [NOK/MWh]		65	114	134	172	258	wv	146	-	-
Fuel costs	x	65 NOK/ MWh	0.4 NOK/ kg	90 øre/ Sm3	90 øre/ Sm3	90 øre/ Sm3	-	0.3 NOK/ kg	-	-
Heat value (lower) [kWh/kg] gas in kWh/Sm3			7.8	11.6	11.6	11.6		2.3		
O & M [NOK/(kW·yr)]		260	40	37	60	25	10	60	162	227
Incentives [NOK/MWh]		0	0	100	0	0	0	100	100	100
Interest rate [%/yr]		7	7	7	7	7	7	7	7	7
Required return on inv [%]		15	15	15	15	15	15	15	15	15

1. hydro and wind uses and index for resource efficiency normalised to 1 at in reference year 2000. Coal, gas and bio use heat rate as index for resource efficiency.

divided by *resource efficiency$_i$* of new plants[1], and *Incentives$_i$* (Eq. 9.10) representing the taxes (-) and subsidies (+) for each technology[2].

Fuel costs in Eq. 9.9 are calculated using *fuel prices* Eq. 12.6-12.11 and *heat rates (*Eq. 12.12-12.14). *Operation* and *maintenance* costs (Eq. 9.11) are mainly based on NVE (2002).

As can be seen in *Figure 9.1*, variables from *Resource availability, Electricity market* and *Technology progress* sector influence the various factors for the technologies in the *profitability assessment.*

As time passes, technology progress and reduce investment costs (Eq. 9.15). The learning multiplier can be defined as exogenous and/or endogenous in the *Technology progress* submodel in *Chapter 11*

9.2.4   Estimated capacity factor

Estimated CF$_i$ differ from *CF$_{i,v}$* in *Chapter 8* only by the efficiency. Efficiency of new investments is given by the *resource efficiency$_i$* in the *Technology progress submodel (Chap-*

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1. Note that *efficiency new* (in *section 10.3* in *Chapter 10*) represented the *average* efficiency of the *Capacity new* vintage stock.
2. In the reference case, renewables and gas with CO2-sequestration receive 100 NOK/MWh as subsidies, while there are no CO2-taxes. The current Swedish TGC market trade certificates around 250 SEK/MWh, and the Current CO_2 quota market price is in the range 60-120 NOK/tonne CO2.

ter 11) while $CF_{i,v}$ depends on the *average* efficiency within each vintage *v*. Apart from *efficiency*, estimated CF_i are identical with $CF_{i,v}$.

.

9.21   *Yearly average CF_i = SLIDINGAVERAGE(CF estimated$_i$)*   *[NOK/MWh]*

9.22   *CF estimated$_i$ = GRAPH$_i$(Price/operating costs$_i$,0.8,0.1,{0,0.154,0.8,1,1})*

Eq. 9.21 computes the yearly average from Eq. 9.22 using a *sliding average* with one-year

Figure 9.3 Estimated capacity factor for each technology
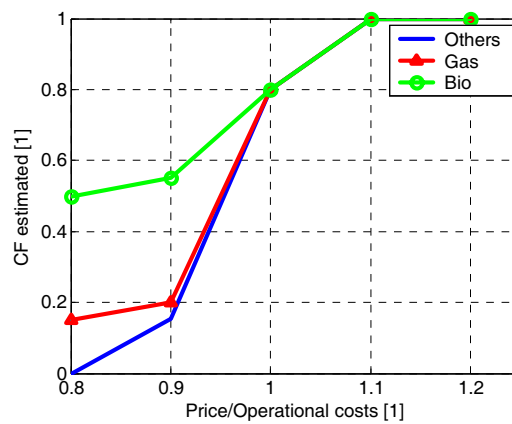
time window. The yearly average CF_i is used to estimate the long run marginal costs in *Chapter 9.19*. Long-run marginal costs stated in [NOK/MWh] depend partly on electricity price, but is the most intuitive way of representing cost of new generation. In perfect, long-run market equilibrium - price should converge towards the long-run marginal cost of the cheapest available technology (including incentives and taxes).

9.3   Investment rate

The question remaining, is the aggregate size of investments for each technology. What is the investment rate given that investments are profitable?

Consider a market in perfect long-run equilibrium, where new capacity replaces old capacity retirements, plus the additional growth in demand and electricity prices equal the long run marginal cost of new capacity[1].

If we base our profitability assessment on price expectations, demand growth should be reflected in the price forecast and thereby the profitability indicator. If we use the equilibrium condition as a reference, then investments should equal replacements of old capacity:

investment rate$_i$ = ageing rate old capacity$_i$

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1. In growing markets, price must actually be higher than long run marginal costs of new capacity, to compensate for the growth.

The formulation reflects the replacement of old capacity. Investment in new capacity is

Figure 9.4 Capacity investments
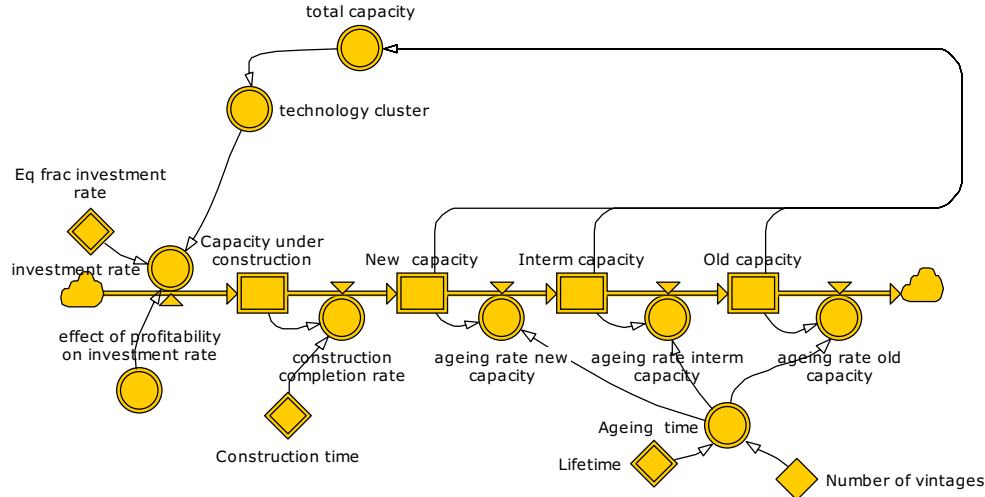
also strongly correlated with new vintages. In fact, there is very few wind turbines in the oldest vintage, most of the wind turbines are in the New capacity vintage. *Total capacity$_i$* makes a good compromise between the replacement of old capacity and new investment trends. The installed capacity of each technology reflects the number of people with experience and knowledge within that technology. For instance, hydropower producers have long traditions within hydropower projects and planning. People from the process industry deal with thermal processes, combustion etc. and have the knowledge to develop thermal plants, but are less knowledgeable in hydropower. Some technologies does however, share many similarities, such as coal, gas and biomass - and switching between such technologies will be within the reach of their expertise.

We therefore introduce a set of technology clusters and make investments proportional to profitability and the size of its technology cluster

Technology cluster
Let T_j denote the subset of technology clusters $j=\{nuclear,thermal,hydro,wind\}$, where nuclear=\{nu\}, thermal=\{ga,gc,gp,bi\} , hydro=\{hy\} and wind=\{wi,wo\}.

9.23   *technology cluster$_{nuclear}$ = total capacity$_{nu}$*   [MW]

9.24   *technology cluster$_{thermal}$*= $\displaystyle\sum_{i \in thermal}$ *total capacity$_i$*   [MW]

9.25   *technology cluster$_{hydro}$= total capacity$_{hy}$*   [MW]

9.26   *technology cluster$_{wind}$* = $\displaystyle\sum_{i \in wind}$ *total capacity$_i$*   [MW]

The two first terms in Eq. 9.27 states that investments are proportional to the amount needed to maintain the capacity of the technology cluster, while the latter term effect of profitability on investment rate$_i$ expresses the relationship between profitability as a function of return on investment ROI$_i$ for technology i (Eq. 9.29).

Investment rate

9.27   *investment rate$_{i,t}$ = Eq fractional investment rate$_i$·technology cluster$_{j|i}$·effect of profitability on investment rate$_i$ $\forall i$*   *[MW/yr]*

9.28   *Eq fractional investment rate$_i$ = 1/Lifetime$_i$*   *[1/yr]*

9.29   *effect of profitability on capacity acquisition$_i$ = GRAPH(ROI$_i$/RROI$_i$,0,0.25,{0 0.03 0.06 0.3 1 2.6 4.3 6.2 7.86 8.7 9})*   *[1]*

9.30   *RROI$_i$= 1+Internal rate of return*   *[1]*

9.31   *Internal rate of return = 0.15*   *[1]*

Similarly, the application rate for permits has the same formulation as investment rate, but with a lower requirement on profitability (Eq. 9.35).

9.32   *permits application rate$_i$ = Eq fractional investment rate$_i$·technology cluster$_{j|i}$·effect of profitability on application rate$_i$ $\forall i$*   *[MW/yr]*

9.33   *effect of profitability on application rate$_i$ = GRAPH(ROI$_i$/RROI applications$_i$ 0 0.25 {0 0.03 0.06 0.3 1 2.6 4.3 6.2 7.86 8.7 9})*   *[1]*

9.34   *RROI applications$_i$= RROI$_i$·RROI application fraction*   *[1]*

9.35   *RROI application fraction$_i$ = 0.5*   *[1]*

Figure 9.5 shows the *effect of profitability on investment rate*. Return on investments are

Figure 9.5 Effect of profitability on capacity acquisition.

a)
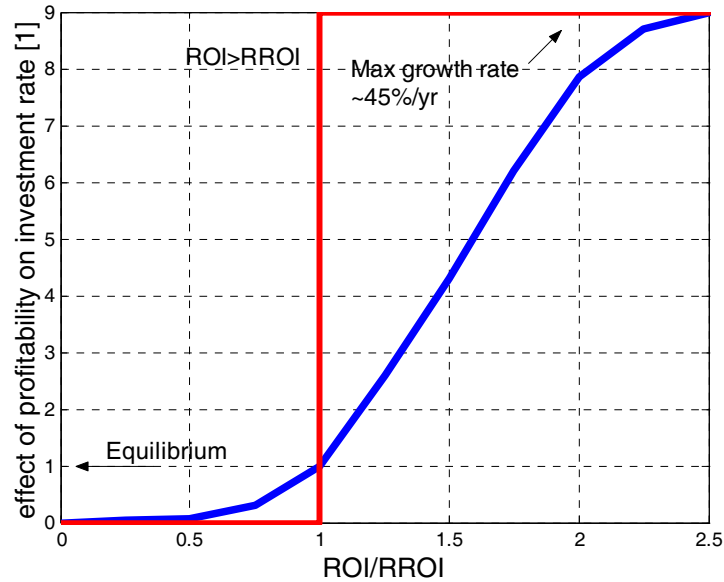
normalised with the required return on investments (Eq. 9.29-9.31), where we assume that 10

to 15% return on investments are required[1]. When $\dfrac{ROI_i}{RROI_i} = 1$, it the *effect of profitability*

on investment rate$_i$ equals 1 and the investment rate equals the depreciation rate of existing capacity stock. The minimum investment rate is zero, and the maximum investment rate is 45% of the technology cluster. The upper constraint stems from the fact that few industries exhibit growth rates above this level. Such constraints are the availability of experienced workers and limited capacity of suppliers. The straight line shows the *effect of profitability*

on investments for the individual investor. If the profitability indicator $\dfrac{ROI_i}{RROI_i}$ is greater than

one, an investment decision is made. However, each investment project may differ from case to case. All the cost elements in the profitability assessment when viewed at an aggregated level will be distributed. For instance, the gas price and the contract for delivery may differ from project to project as the result of negotiations between parties. The investment costs depend on the conditions of existing infrastructure, the financial terms of the loan. Expectations of future prices, and investment criteria differ as well.

Rather than representing all of these parameters as statistical distributions, we can interpret the function *effect of profitability on capacity acquisition* as a *cumulative distribution* resulting from the underlying statistical variables discussed in this section. The cumulative

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1. According to Fortum (2002), average return of European utilities were 15% in 2000-2001.

distribution of profitability may then look like in *Figure 9.5*. The normalised profitability along the x-axis ranges from 0 up to 2.5. Along the y-axis, the *effect of profitability on capacity acquisition* has the shape of a cumulative distribution function scaled to unity when it is marginally profitable to invest in new capacity (i.e. the market is in long-run equilibrium when long-run marginal costs equal the forward price). The curve is upward limited to a factor that yields a maximum growth rate of 45% per year for the technology in quest. Few industries sustain at growth rate more than this. Investment of new capacity requires resources from manufacturers and their suppliers, administrative resources in terms of planning and permits, employees with relevant skills etc. - all of which are resources that constrain growth rates.

Figure 9.6 Empirical observation of yearly capacity additions versus expected internal rate of return for single-owners of wind turbines in Denmark (source: Morthorst, 1999)
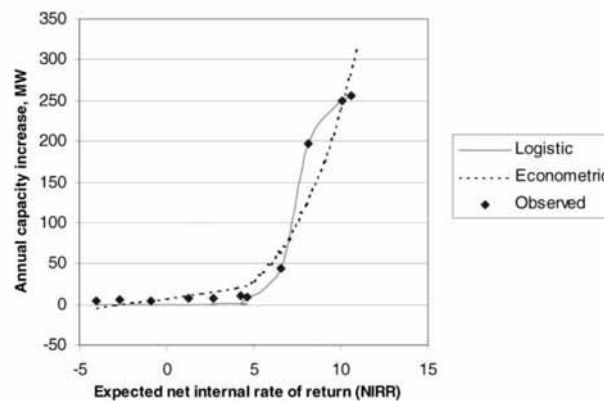
The relationship can furthermore be derived from empirical analysis. There is surprisingly little theory or information to obtain from standard economic literature on this relationship. Morthorst (1999) made an empirical estimation of this relationship on wind turbine owners in Denmark, and came up with an s-shaped curve for private-owned turbines as argued by our analytical discussion. A deeper search into economics literature would probably provide more empirical evidence studies on this relationship. Nevertheless, the constraining resources give rise to dynamics that does not appear in partial equilibrium models.

9.4   Implications for model behaviour

Different assumptions underlie the investment behaviour between our dynamic profitability assessment model and the existing partial equilibrium optimisation models NORDMOD-T and MARKAL. Investors are here assumed to be boundedly rational rather than rational, which implies that they make decisions based on a limited set of information, using heuristic decision rules. Optimisation models assume investors as a result will find the optimal amount of capacity to be invested in a timely manner, usually ignoring problematic time delays involved in the process. As a result, partial equilibrium models will tend towards long-run equi-

librium, while this model can exhibit significant periods of over investments and capacity deficits resulting from the behavioural assumptions of investors and the time delays involved.

Furthermore, the investment rate is a nonlinear relationship of installed capacity and the profitability that capture constraints on investment rates. Both nonlinearities and time delays can in principle be included in optimisation models, but in practice this will render the fairly data-intensive optimisation models too difficult to solve (Gritsevskyi et al., 2000). The resulting behaviour of capacity development using the nonlinear formulations is in accordance with historically observed patterns that typically exhibit s-shaped diffusion curves for technologies.

Finally, profitability assessment in the long-term influenced by important feedbacks from technology progress, resource availability and the electricity market.

Optimisation and partial equilibrium models assuming rational expectations are prescriptive and provides a reference mode of how things should be in a perfect market. However, they are less useful in the process of designing the necessary conditions that is required for the electricity market to perform nearly as a perfect market. In order to design market structures - rules and regulations that provide a stable, well-working market, the behaviour of participants and their real decision policies subject to various rules and regulations must be captured in order to understand the total impact and future development of the electricity market. The dynamic simulation model presented here can provide such a tool.

9.5   References

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10 Capacity acquisition
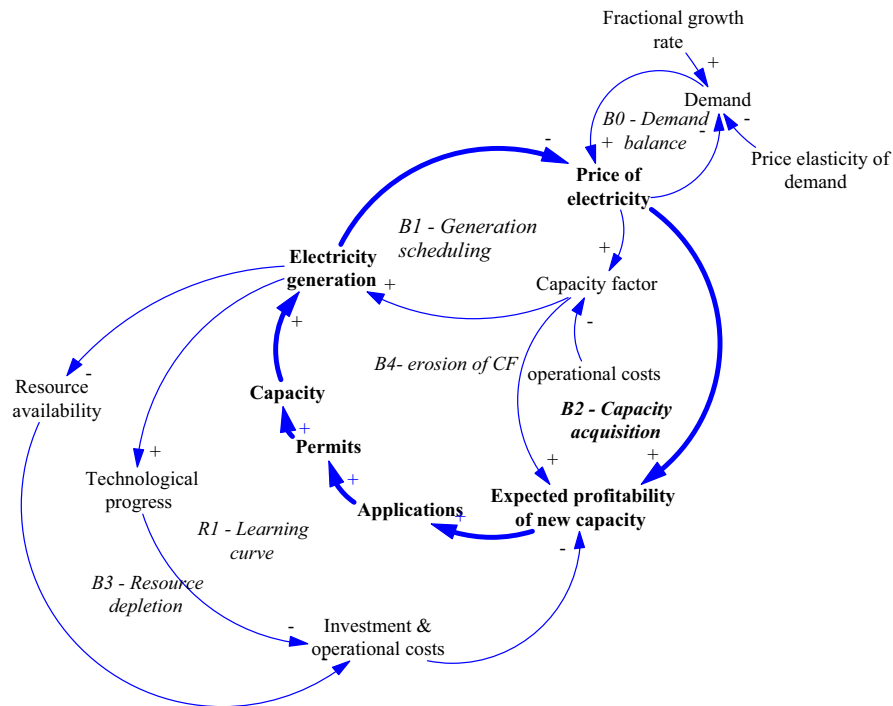
C apacity investments*, or the lack of it has become a major concern in deregulated electricity markets (Finon et al. 2004; Econ, 2002) Most electricity markets subject to deregulation inherited overcapacity from the regulated regime. The Nordic market is now approaching a situation where reserve margins are becoming tighter and new investments are needed.

The *capacity acquisition loop B2* in the above figure illustrates the process of capacity investments, where long time delays are involved in expectation formation, application processing and the construction of new capacity. Several authors have pointed out that the electricity market can enter into cyclical modes of behaviour (Bunn and Larsen, 1992, 1994; Ford 1999, 2001; Arango et al., 2005; Botterud et al. 2002), which is typical in other markets, such as the pulp & paper, aluminium, oil tanker industry, the airline industry etc.

Figure 10.1 shows the stock and flow diagram of the *Capacity acquisition* process. In the following sections, we present *Application processing*, *construction* and the *vintage* structure of the technologies. *Profitability assessment* submodel outlined in the previous chapter, which also determines the initiation of permit applications, determines the acquisition of new capacity. The final section of this chapter presents *efficiency* of each technology as an age-

dependent attribute. *Table 10.1* summarises the average time delays for permit applications,

Figure 10.1 Stock & flow diagram of capacity acquisition. The supply chain consists of *Application processing* (dashed box), construction and the vintage of each technology. The *Coflow resource intensity* submodel keeps track of the *average* resource intensity accompanying each capacity vintage stock.
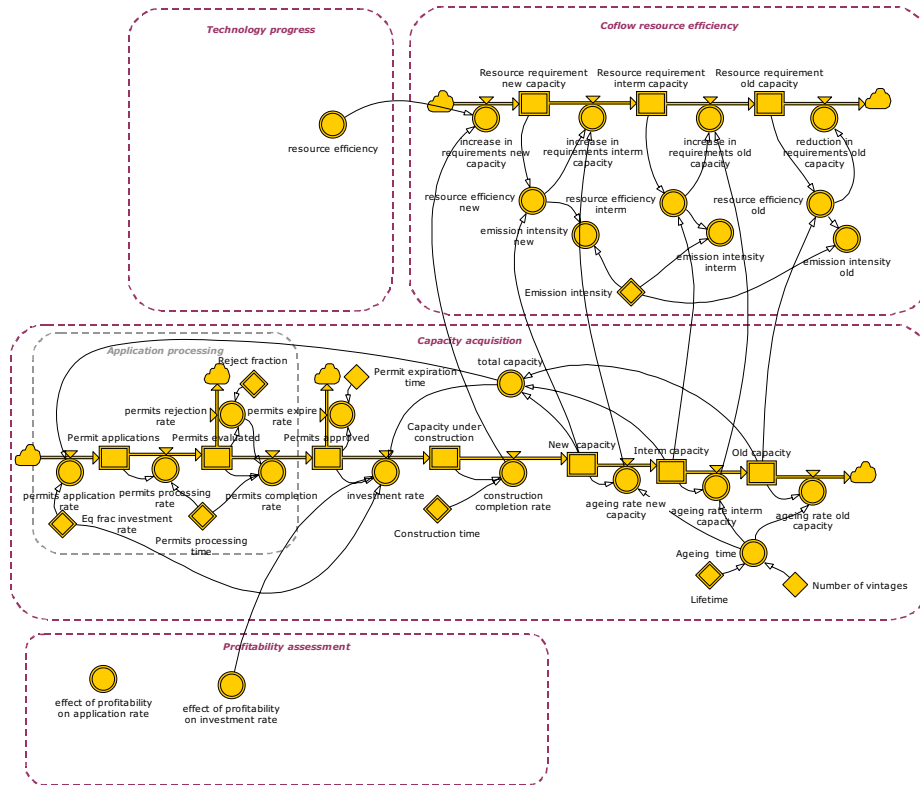
construction time and lifetime of each technology.

Table 10.1 Time delays in capacity acquisition

[yr]	thermal					renewables			
	nu	co	ga	gc	gp	hy	bi	wi	wo
Application processing time	3	1.5	1.5	1.5	1	2.5	1.4	1.4	1.4
Construction time	7	5	3	5	1	3	1	1	1.5
Lifetime (vintages 1/3 each)	40	30	30	30	30	40	30	20	20

10.1   Application processing

We will first have a look at delays in the process of submitting applications for permits (construction permits, emission permits etc.) necessary to develop new projects (see the box *Application processing* in *Figure 10.2*). Delays in the application process can vary from country to country according to their administrative procedures and regulations, whereas construction delays are mainly technology specific. To give an estimate of the delays involved, available data and discussions with staff from regulating authorities in the Nordic countries

took place[1]. In all countries, several laws are effective: Planning and construction regulations, environmental regulations and sometimes special laws of cultural inheritance and international agreements apply. Delays in the application process increases costs for developers[2]

Figure 10.2 Application processing
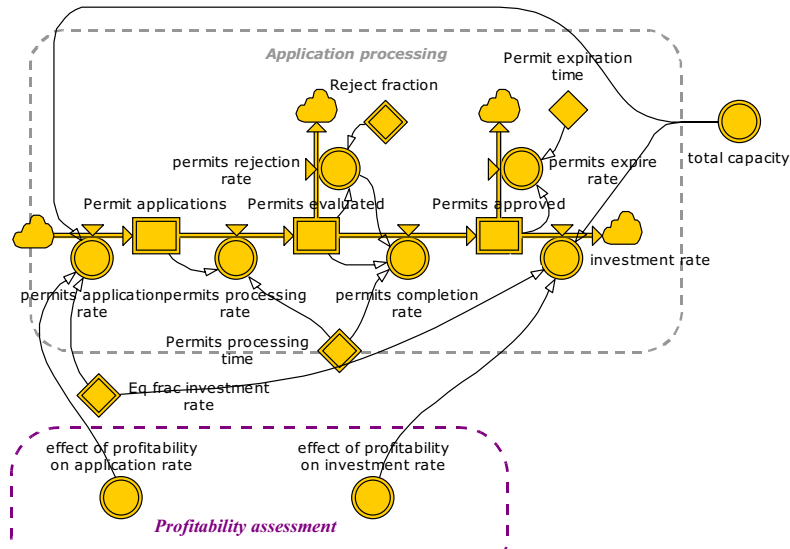
Application processing submodel $\forall i \in T$

10.1   *Permit applications$_{i,t}$ =Permit applications$_{i,0}$+ $\int$(permit application rate$_{i,t}$ -permits processing rate$_{i,t}$)·dt*   [MW]

10.2   *Permit applications$_{i,0}$ = {1600,0,164,400,164,0,243,250,25}*   [MW]

10.3   *permit application rate$_{i,t}$ =Eq fractional investment rate$_i$· effect of profitability on application rate$_i$· capacity$_i$*   [MW/yr]

10.4   *Eq fractional investment rate$_i$={1/40,1/30,1/30,1/30,1/30,1/40,1/30,1/20,1/20}[1/yr]*

10.5   *permits processing rate $_{i,t}$=Permit applications$_i$ /Permits processing time$_i$*   [MW/yr]

10.6   *Permits processing time = {3,1.5,1.5,1.5,1,2.5,1.4,1.4,1.4}/2*   [yr]

10.7   *Permits evaluated$_{i,t}$ =Permits evaluated$_{i,0}$+ $\int$(permits completion rate$_{i,t}$-permits rejection rate$_{i,t}$)·dt*

10.8   *Permits evaluated$_{i,0}$ = {0,0,164,400,164,0,243,250,25}*   [MW]

10.9   *permits completion rate$_{i,t}$ = Permits evaluated$_i$/Permits processing time$_i$-permits rejection rate$_{i,t}$*   [MW/yr]

10.10   *permits rejection rate$_{i,t}$ = Permits evaluated$_i$·Reject fraction$_i$*   [MW/yr]

10.11   *Reject fraction$_i$ = {0,1,0,0,0,0,0,0,0}*   [%/yr]

10.12   *Permits approved$_{i,t}$ = Permits approved$_{i,0}$+ $\int$(permits completion rate$_{i,t}$-investment rate$_{i,t}$ - permits expire rate$_{i,t}$)·dt*   [MW]

10.13   *Permits approved$_{i,0}$ = {0,0,82,400,82,0,122,125,13}*   [MW]

10.14   *permits expire rate$_{i,t}$ = Permits approved$_i$ / Permit expiration time*   [MW/yr]

10.15   *Permits expiration time = 3*   [yr]

In the *Application processing submodel* presented in Eq. 10.1 - Eq. 10.15, the application process is modelled as a second-order process (*Permit applications* and *Permits evaluated*) Permits then enter the stock of *Permits approved*.

Permit application rate (Eq. 10.3) has in principle the same formulation as the *investment rate$_i$* discussed in *Chapter 9*.

Permits processing time in Eq. 10.6 is the average time needed for the application process. Since the process is distributed on *n=2* stocks, *Permits processing time* is divided by *n=2* (see Forrester, 1961, ch 9). *Table 10.1* summarise the estimated application processing time delays for the technologies.

Permits expire within three years. The *permits expire rate* (Eq. 10.14) describes this process. Often, developers choose to renew their permits, and this can simply be adjusted for by extending the *Permit expiration time* in Eq. 10.15.

Permits can be rejected, which is what the *permits rejected rate* outflow from *Permits evaluated* describe. The *Reject fraction* in Eq. 10.11 for each technology is exogenously determined by the user. Initially, the reject fraction is set to *one* for coal, and *zero* for the remaining technologies.

Initial values of the stocks *Permit applications, Permits evaluated* and *Permits approved* are set to be in equilibrium from the start of the simulation (see *Chapter 9* for a discussion on the long run equilibrium condition).

NVE observed that there is no close relationship between profitability and permit applications. Permit applications can be developed for strategic reasons in the case of wind power and gas power, where transmission, resources or authorities limit the feasible number of projects. Well aware of the delays in the application process utilities can also send applica-

tions just to "fill the pipeline", viewing permits as an option which is not necessarily realised into investment decisions.

10.1.1 Permits for wind power

As of November 2002, 11 applications have been processed by NVE, while 28 applications have been processed by the Skåne and Gotland County, which is the main area of development for wind in Sweden (see Appendix D - Permit applications). New wind power development in Norway differs from Sweden and Denmark by having a more centralised planning approach. Applications are coordinated centrally by NVE, guiding the applicants through the process.

In Sweden, the process is more decentralised. Developers must obtain a number of permits from the county administration, the energy authorities and a number of other authorities depending on the status of the project[1].

In Denmark, the county administration, Danish Energy Authority and The Ministry of Environment issue separate permits. Finland has had less focus on wind power, but procedures for recommendations have been made[2].

We assume that our sample of applications being processed for wind power adequately represents the application process in the Nordic countries in the sense that the same kind of procedures has to be conducted whenever stake holders and interested parties are involved in the process. Given the time horizon of our model, routines of application processing are sub-

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1. See www.vindkraft.nu (in Swedish)
2. Miljöministeriet, 2001: *Ympäristölainsäädännon soveltaminen tuulivoimarakentamisessa.* (In Finnish)

ject to change during this period, so that estimates of the application process that are more precise would add little to the analysis.

Figure 10.3 Histogram of $n = 39$ **application delays for wind power. Time delay (x-axis) measured from submission to approval/reject, measured in months. The Erlang distribution of order 2** $\mu = 16$ **months/application and** $\sigma = 11.5$ **months/application fits the histogram.**

a)

time [months]
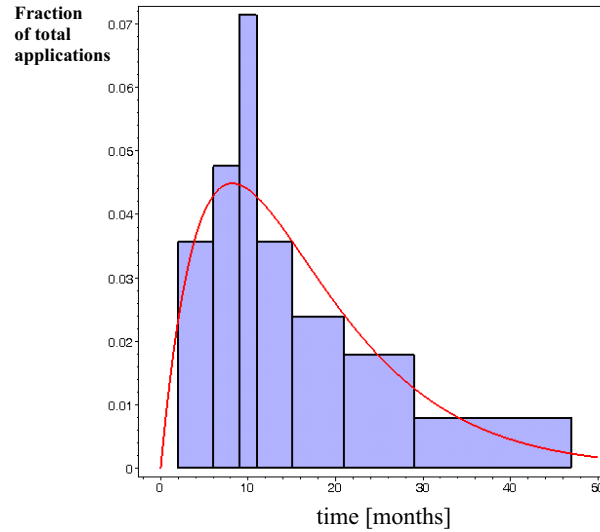
The time delay from submission of each application submitted to the final approval/reject was calculated for the $n = 39$ samples are shown in the histogram in *Figure 10.3*. There is a mean delay time μ of 16 months/application, and a standard deviation of $\sigma = 11.5$ months/application. The distribution of the delay helps us characterise the order of the application process delay using the Erlang distribution defined as:

$$P(t) = \frac{\left(\frac{n}{\mu}\right)^n}{(n-1)!} \cdot t^{(n-1)} \cdot e^{\left(-\left(\frac{n}{\mu}\right) \cdot t\right)} \qquad t > 0 \tag{i}$$

where t is time and n is the order of the delay (Sterman, 2000 p465). The Erlang distribution represents the pulse response of an nth order cascading first order stock and flow structure like the ones in *Figure 10.1* and *10.2*. The variance of an nth order Erlang distribution is:

$$\sigma^2 = \frac{\mu^2}{n} \tag{ii}$$

Thus

$$n = \text{INT}\left(\frac{\mu^2}{\sigma^2}\right) \tag{iii}$$

serves as an estimator of the order of the delay process. In *Figure 10.3*, the continuous line shows the Erlang distribution with μ, σ corresponding to the histogram of applications. By applying Eq. (iii), the estimated order of the delay process is $\hat{n} = 2$. Though the average

delay time μ may differ from technology to technology, the order should be similar for the other technologies as well.

10.1.2 Permits for bio energy

Finland and Sweden have the largest share of electricity generation from bio, mostly CHP in industry. There is no electricity generation from bioenergy in Norway - but there is a potential for future development as alternatives to electricity for heating is underdeveloped. Denmark makes extensive us of CHP in district heating. The application procedure should be about the same as for wind power (~16 months)

10.1.3 Permits for hydropower

Several conflicting considerations makes hydropower projects special in the context of applications and permits. Nature conservation, local employment, tourism and fishing are among controversies. Moreover, hydropower projects will influence potential developments downstream. Final decisions are made in Parliament for larger projects, often being contested by NGO's. According to NVE, permits take approximately 2.5 years to process[1].

Small scale hydropower requires less rigorous application procedures. NVE recently estimated a large potential for small scale hydropower.

10.1.4 Permits for fossil and nuclear

Gas power remains a controversial issue in Norway, which is also reflected by the application process. In addition to NVE, the Norwegian Pollution Control Authority (SFT) under the Ministry of Oil and Energy must grant emission permits for industrial plants. In 1996, the first application was sent and in October 2002, necessary permits were finally given. These three applications create a lot of political turmoil and still do. Uncertainties about the development of the CO_2 quota market and its rules concerning joint implementation, legal aspects concerning international environmental agreements (i.e. the Gothenborg protocol) may have postponed decisions several times. The application delays range from 8 months to 3 years for the Norwegian case.

The most probable development in Denmark is not necesarily new sites but rather modification or replacement of existing ones, especially conversion from coal to gas. Utilising existing sites and infrastructure will reduce the need for permits as well.

Table 10.2 Sample of applications for gas power

Unit	Size [MW]	Application sent	Approved	On line
Skærbæk, Denmark	400 gas + 400 coal	06.12.1991	03.04.1992	late 1997
Avedøre, Denmark	570 (multifuel gas bio and oil)	09.1994	03.1997[1]	09.2001
Kårstø and Kollsnes, Norway	2 x 400 natural gas	23.02.1996	10.1996 11.1996[2] 10.2002 (renewal)	not yet (as of 2004)

1. NVE (Norwegian Water Resources and Energy Directorate) maintain a database of each hydropower project, but several of these projects are remainings of submissions prior to deregulation, and is therefore not a good indicator for profitable projects intended for development.

Table 10.2 Sample of applications for gas power

Unit	Size [MW]	Application sent	Approved	On line
Skogn, Nor-way	**800 NGCC, inte-grated with paper-mill**	**04.03.1999**	**29.11.2000[3]**	**not yet**

1. First application of a pure coal fired plant rejected. Second application approved for multifuel plant. (Environmental assessment started primo 95, approved 06.96)
2. Construction permit was contested by several NGO's and stake holders. Permit reinforced after processing the complaints.
3. The application lead to the resign of the Government 9. March 2000. New government instructed SFT to approve application.

New coal power is less relevant, as their levelised energy costs (long-run marginal costs) are considered higher than for gas and the uncertainty about future CO_2 quotas are also to the disadvantage of coal. On the other hand, soaring gas prices make investments in natural gas risky, but the capital investments are in turn lower for gas than for coal.

There is a political decision of no new coal power in Denmark. Likewise, coal plants in Norway and Sweden is in conflict with environmental objectives, while Finland does not impose restrictions on the type of new plants.

Sweden has since 1980 had a goal of phasing out nuclear plants (even before the end of its technical lifetime), and the industry is in negotiations with authorities for a time schedule for a phasing out nuclear capacity. Barsebäck I has been shut down, and Barsebäck II is about to close. This policy has lately been under attack now that Finland decided to expand their nuclear capacity.

10.2   Capacity vintages

This section deals with the *construction* and *vintage* of capacity shown in *Figure 10.4*. Construction and vintages adds inertia to the system.

Capacity under construction Eq. 10.16 - Eq. 10.21 is determined by the investment rate in Eq. 10.18. The investment rate depends on the *Equilibrium fractional investment rate (Eq. 10.4), effect of profitability on investment rate$_i$* (see the *Profitability assessment* submodel), *capacity$_i$, (Eq. 10.35)* and is constrained by the availability of *Permits approved* (Eq. 10.12). Representing investment decisions is an important aspect of the model, which will be discussed in the next section.

Projects initiated enter the stock of *Capacity under construction*, and the various technologies appear to have different lead times, nuclear at the upper end, wind and bio at the lower end. *Table 10.1* shows the lead times used corresponding to Eq. 10.21. Capacity on line enters the first vintage *New Capacity*, moving onto the *Intermediate* and *Old Capacity* before being phased out by the end of the *Lifetime* (Eq. 10.22-Eq. 10.34). Capacity reside on average one third of its lifetime in each vintage category, for instance gas and coal will (on average) spend 10 years in each vintage category totaling 30 years lifetime, whereas wind with 20 years lifetime spend on average short of 7 years in each vintage category.

The number of vintages has not been estimated from statistical data, but in principle, the same approach canbe followed as for the application process model[1]. Forrester (1961,

Figure 10.4 Investments, Construction and Capacity vintages
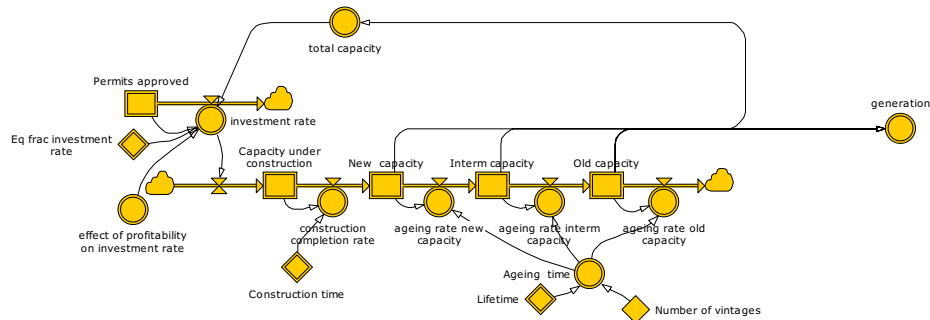
pp419-420) pointed out that systems usually are not sensitive to the time response of the delay representation, unless the systems are very simple. With $n = 3$ vintages, the standard deviation of an average 30 years lifetime according to Eq. (ii) of the lifetime is

$$\sigma = \sqrt{\frac{(Lifetime/n)^2}{n}} \approx 5.8 \text{ yr},$$ which is quite plausible. The early version presented in Vogstad et al. (2002) represented capacity as a single stock. The main reasons to include a vintage structure, is a better representation of the time delays involved in phasing out existing capacity, and the representation of conversion efficiency of each of the technologies as an age-dependent attribute in making the supply curve consistent with new investments.

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1. Nordel, www.nordel.org maintains statistics of all capacity additions/retirements from the Nordic countries since 1976 (26 years). Supplemented with older statistics, the lifetime distribution.

Capacity vintage submodel $\forall i \in T$

10.16 *Capacity under construction$_{i,t}$ = Capacity under construction$_{i,0}$ + $\int$(investment rate$_{i,t}$- construction completion rate$_{i,t}$)$\cdot$dt*   *[MW]*

10.17 *Capacity under construction$_{i,0}$ = {0,0,164,400,164,0,244,750,50}*   *[MW]*

10.18 *investment rate$_{i,t}$ = MIN(Permits approved/Initiation time,effect of profitability on investment rate$_i$$\cdot$capacity$_i$$\cdot$Eq frac investment rate$_i$)*   *[MW/yr]*

10.19 *Initiation time = 1*   *[mo]*

10.20 *construction completion rate$_{i,t}$ = Capacity under construction$_i$ /Construction time$_i$*   *[MW/yr]*

10.21 *Construction time = {6,3,2,4,1,3,1,1,1.5}*   *[yr]*

10.22 *New capacity$_{i,t}$=New capacity$_{i,0}$+ $\int$(construction completion rate$_{i,t}$ - ageing rate new capacity$_{i,t}$)$\cdot$dt*   *[MW]*

10.23 *New capacity$_{i,0}$ = {0,4149,858,0,8,15547,614,2000,250}*   *[MW]*

10.24 *ageing rate new capacity$_{i,t}$ = New capacity$_i$ / Ageing time$_i$*   *[MW/yr]*

10.25 *Interm capacity$_{i,t}$=Interm capacity$_{i,0}$+ $\int$(ageing rate new capacity$_{i,t}$ - ageing rate interm capacity$_{i,t}$)$\cdot$dt*

10.26 *Interm capacity$_{i,0}$ = {5202,5374,1661,0,509,15547,3038,500,0}*   *[MW]*

10.27 *ageing rate interm capacity$_{i,t}$ = Interm capacity$_i$ / Ageing time$_i$*   *[MW/yr]*

10.28 *Interm capacity$_{i,t}$=Interm capacity$_{i,0}$+ $\int$(ageing rate new capacity$_{i,t}$ - ageing rate interm capacity$_{i,t}$)$\cdot$dt*   *[MW]*

10.29 *Old capacity$_{i,t}$=Old capacity$_{i,0}$+ $\int$(ageing rate interm capacity$_{i,t}$ - ageing rate old capacity$_{i,t}$)$\cdot$dt*

10.30 *Old capacity$_{i,0}$ = {7460,1687,0,0,2132,15547,0,0,0}*   *[MW]*

10.31 *ageing rate old capacity$_{i,t}$ = Old capacity$_i$ / Ageing time$_i$*   *[MW/yr]*

10.32 *Ageing time$_i$ = Lifetime$_i$/Number of vintages*   *[yr]*

10.33 *Lifetime$_i$ = {40,30,30,30,30,∞,30,20,20}*   *[yr]*

10.34 *Number of vintages = 3*   *[1]*

10.35 *capacity$_i$ = $\sum\limits_{v \in V}$ Capacity$_{i,v}$*   *[MW]*

Figure 10.5 shows the initial installed capacity grouped into vintages and technologies.

Figure 10.5 Initial installed capacity grouped into vintages and technologies.
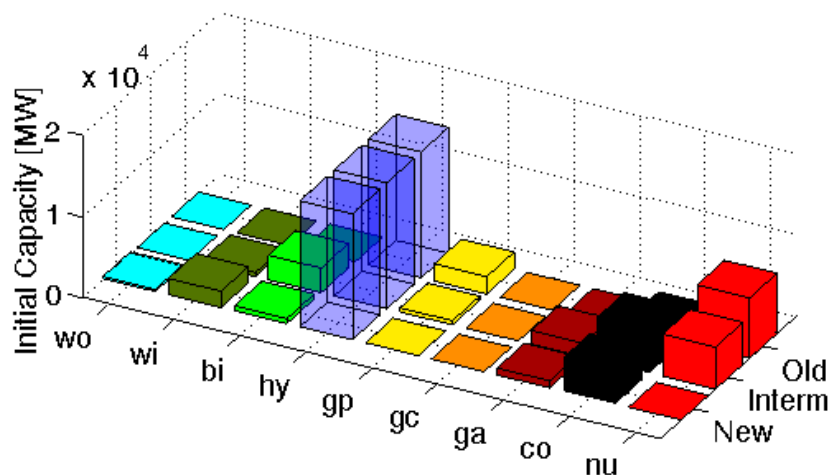
Initial capacity vintages for 2000 were far from equilibrium (se Appendix B - Data set for details). In general, few investments have been made after deregulation, except for wind power. New capacities in coal and gas, stems from the early nineties (coal in Finland (1994), Fynsverket (674 MW in 1991) and Esbjerg (616 MW in 1992) in Denmark. The electricity sector had a significant amount of overcapacity before deregulation. Demand increase and depreciation of existing capacity is about to close this gap at the end of the transition stage. Of particular interest is the development in nuclear capacity, where Old capacity constitutes the largest share.

Likewise, peak load capacity is diminishing. Looking at the levelised energy costs of peak load, returns can hardly be covered by the electricity market or balance market alone. This concern will also appear in the later simulations, as prices become more volatile due to reduced flexibility on the supply side. Possibilities for increased flexibility on the demand side exist, that can compensate for some of the diminishing peak load capacity (see *Chapter 13*).

Installed hydro capacity is distributed equally for each vintage, although this does not really reflect reality. However, we have set the depreciation of hydro to zero for reasons explained above.

With this model formulation, we are able to simulate both the transition between technologies over the next 30 years, *and* portray the change in vintages. The reason for representing vintages, is primarily to represent the inertia of installed capacity and how it influences the market; secondly, to distinguish between the efficiency of new plants and old plants, which influence the marginal costs as well as emissions and the emissions as will be demonstrated in the *Generation scheduling* chapter.

In this model formulation, we do not consider retrofits of existing capacity. System dynamic vintage models with coflows and retrofits have been developed in previous work (Sterman, 2000), and the model can be extended to include retrofits. It may be an important to include the possibility for retrofits as well, because conversion of coal plants to gas within existing infrastructure is potentially a cheaper alternative for new generation than building new plants. Furthermore, replacement of old wind turbines in favourable sites and even the

conversion of coal, oil or gas into bio or co-firing could provide cheaper, faster and more cost-effective alternatives for investment. If the CO_2 sequestration technique becomes economic viable, retrofitting old coal plants, such as Aasnes in Kalundborg is probably more relevant.

10.3 Resource efficiency as age-dependent attribute of capacity

When a new plant is being built, its technical characteristics will remain throughout its lifetime. This is sometimes referred to as a putty-clay model of capital equipment (Fiddaman 1997; Sterman, 2000). The fuel efficiency of new plants, however is better than for old plants, and the resource efficiency of each vintage depends on how fast the technology has improved and the distribution of investments over time. "Coflows" (Sterman, 2000) can be used to keep track of such age-dependent attributes.

Sensitivity analysis from the simplified model in *Chapter 5* showed that representing the vintage structure had impact on the diffusion rate of new technologies. Long life times of existing capacity with sunk costs hamper the introduction of new technologies. Furthermore, the replacements of old capacity with new should be adequately represented to analyse changes in price and emissions.

In the simplified model and earlier versions of this model (Vogstad et al. 2002), the marginal costs were aggregated into one supply curve for each technology. In other words, the marginal costs of a technology was independent of age by assigning each technology a fixed cost distribution based on the costs of currently installed capacity in (see Appendix B - Data set). Nevertheless, during the course of 30 years, technology progresses, and marginal costs of new capacity differ from old plants due to improvements in design and efficiency.

We therefore introduce *resource efficiency* as an age-dependent parameter using a coflow structure as shown in *Figure 10.6*. The equation set *Coflow resource efficiency* (Eq. 10.36-

Figure 10.6 Energy conversion efficiency coflow structure
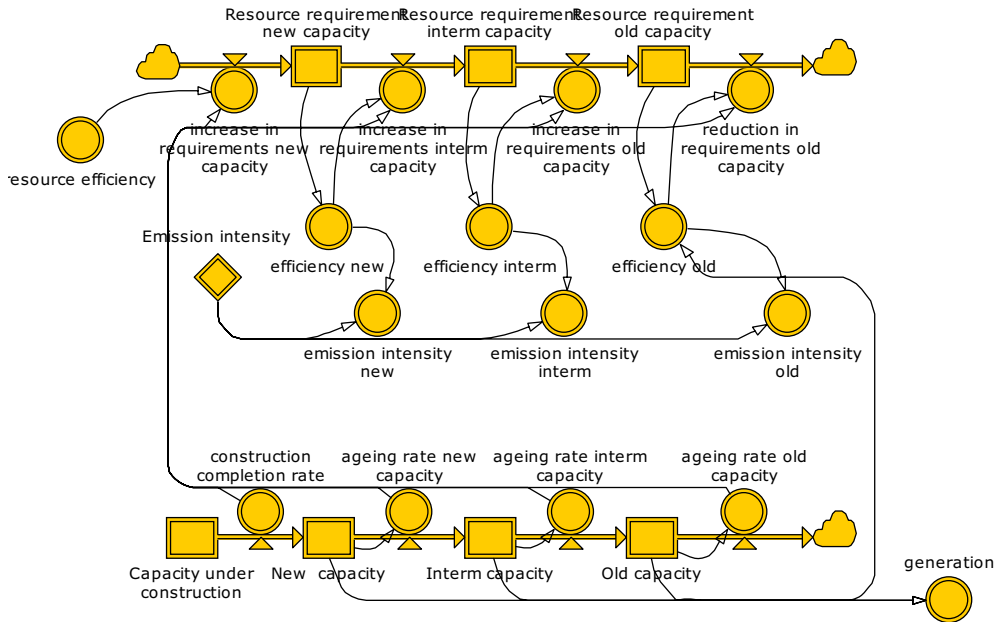
Eq. 10.48) lists the corresponding coflow structure equations used to compute the *efficiency* for each vintage (Eq. 10.39, 10.43 and 10.48). Efficiency of each technology is important in the calculation of the *operational costs*$_{i,v}$ and the *emission intensity*$_{i,v}$ in *Chapter 8 - Generation scheduling*.

Coflow resource efficiency

10.36 *Resource requirements new capacity$_{i,t}$=Resource requirements new capacity$_{i,0}$+ ∫(increase in requirements new capacity$_{i,t}$ - increase in requirements interm capacity$_{i,t}$)˙dt*   *[MW˙1]*

10.37 *Resource requirements new capacity$_{i,0}$ = {0, 1867, 472, 0, 24, 15547, 340, 2000, 100} [MW]*

10.38 *increase in requirements interm capacity$_{i,t}$ =efficiency new$_i$ ˙construction completion rate$_{i,t}$*   *[MW/yr]*

10.39 *efficiency new$_i$ = Resource requirements new capacity$_i$ / New capacity$_i$*   *[1]*

10.40 *Resource requirements interm capacity$_{i,t}$=Resource requirements interm capacity$_{i,0}$+ ∫(increase in requirements interm capacity$_{i,t}$ - increase in requirements old capacity$_{i,t}$)˙dt*   *[MW˙1]*

10.41 *Resource requirements interm capacity$_{i,0}$ = {5046, 2150, 747, 0, 127, 14770, 1526, 450, 0} [MW]*

10.42 *increase in requirements interm capacity$_{i,t}$ =efficiency interm$_i$ ˙ageing rate new capacity$_{i,t}$*   *[MW/yr]*

10.43 *efficiency interm$_i$ = Resource requirements interm capacity$_i$ / Interm capacity$_i$*   *[1]*

10.44 *Resource requirements old capacity$_{i,t}$=Resource requirements old capacity$_{i,0}$+ ∫(increase in requirements old capacity$_{i,t}$ - decrease in requirements old capacity$_{i,t}$)˙dt*   *[MW˙1]*

10.45 *Resource requirements old capacity$_{i,0}$ = {7460, 1687, 0, 0, 2132, 15547, 0, 0, 0} [MW]*

10.46 *increase in requirements old capacity$_{i,t}$ = efficiency interm$_i$ ˙ageing rate interm capacity$_{i,t}$*

10.47 *decrease in requirements old capacity$_{i,t}$ =efficiency old capacity$_i$ ˙ageing rate old capacity$_{i,t}$*   *[MW/yr]*

10.48 *efficiency old$_i$ = Resource requirements old capacity$_i$ / Old capacity$_i$*   *[1]*

For each vintage, there is therefore a stock of *Resource requirements* which is the total amount of resources used in the conversion process. For example:

Resource requirement new$_i$ = Capacity$_i$/efficiency new$_i$ *(iv)*

where efficiency new$_i$ = $\dfrac{\text{energy resource output}}{\text{energy input}}$ in [MWh/MWh]

The resource requirements are thus (in the case of thermal units) the product of installed capacity and its resource consumption per output of electricity. The increase of resource efficiency entering the *New Capacity* stock is determined by the *Technology progress* submodel. Improvements in resource efficiency for each vintage then depend on its turnover as well as the turnover of the preceding vintage.

Figure 10.7 shows the initial resource efficiency assumed for each technology and vintage. Zero indicates there is no capacity present in that group. The resource efficiency measure for nuclear coal, gas and bio corresponds to the heat rate. For hydro and wind, an efficiency index is normalised to 1 in year 2000 is used. Efficiency of the capacity vintages

changes slowly. Efficiency improvements accompanying new investments were presented in *Chapter 11*.

Figure 10.7 Initial resource efficiency corresponding to heat rate for thermal technologies. Nuclear and renewables use an efficiency index, normalised to 1 for the efficiency of new technologies in 2000. The value 0 indicates no capacity in that vintage.
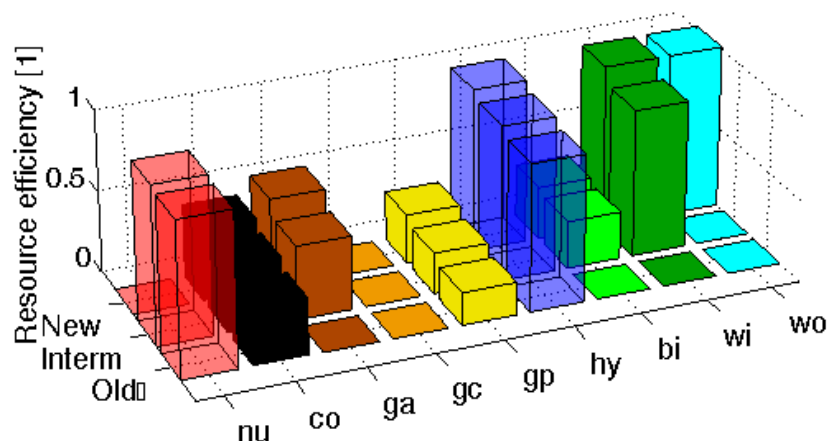
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11 Technology progress
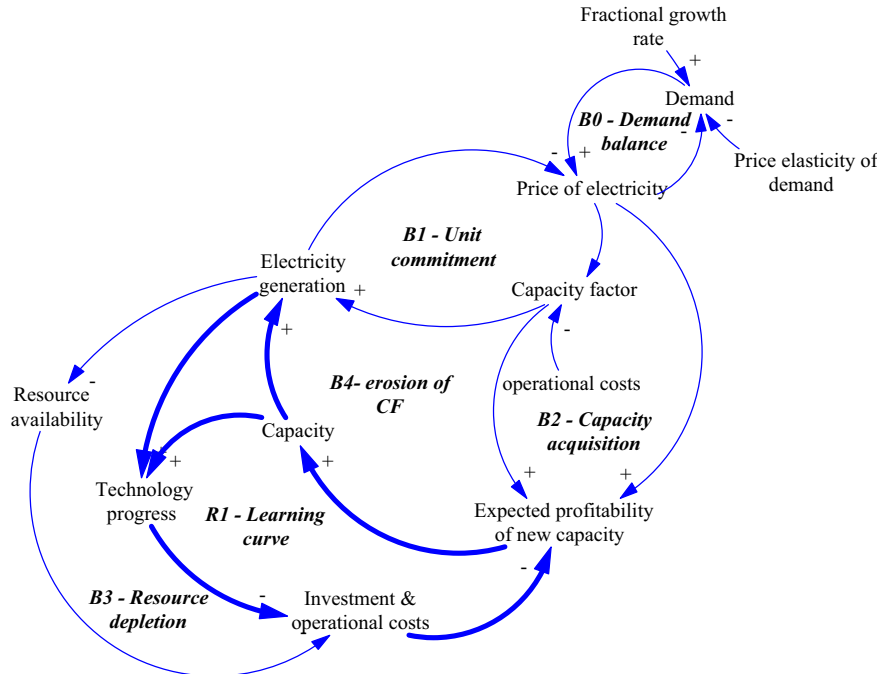
I t is widely recognised that technology change is a main determinant of our energy future. But technological change is not something exogenous that just "happens" independent of present choices. Schumpeter argued that technology changes arise from within the economy. The economy is a network of processes that constitute interacting feedbacks of diminishing returns (negative feedbacks) and increasing returns (positive feedbacks). The market mechanism and economies of scale are two examples of negative feedbacks. Technology progress and network effects provide examples of positive feedbacks.

Present energy models for long-term decision support mainly focus on negative feedback processes that drive the model towards some equilibrium. In negative feedback economies, small changes will be attenuated by the system, without affecting the long-term equilibrium. For instance, an R&D programme leading to the improvement of one technology will not appear have a significant effect. In a positive feedback economy, small changes can amplify to change the course of future technology pathways. Improving the competitiveness of one technology through R&D stimulates more investments in the technology, which improves its competitiveness, forming a positive feedback process.

11.1   Underpinnings of technology progress

Wright (1932) first studied the relationship between costs and experience measured as cumulative production in their manufacturing of aeroplanes. Arrows (1962) attributed this learning-by-doing effect to the improvements from performing repetitive tasks. Boston Consulting Group (1968) analysed total costs of technologies and collected empirical evidence for learning (measured by cumulative production) and total costs. The standard mathematical representation of this relationship is:

$$C = C_0 \cdot \left(\frac{P}{P_0} \right)^{-b} \hspace{4cm} (i)$$

where c and P is the cost and cumulative production level at time t C_0 and P_0 is the corresponding initial cost and cumulative production, while b is the *learning index*. For each doubling of cumulative production, the relative cost reduction is defined as the *learning rate* $LR = (1 - 2^{-b})$. or alternatively through the *progress ratio* $PR = 2^{-b}$.

11.2   Learning curves of energy technologies

Long-term challenges such as sustainability and global warming have put focus on long-term energy policies and stimulation of new technologies. McDonald and Schrattenholzer (2000) provide a recent overview of the learning rates of various energy technologies. *Figure 11.1* shows the distribution of learning rates for various energy technologies and the distribution is comparable to learning rates of technologies in general. Most technologies show learning rates in the range 10 to 20%.

IEA (2000) outlines how the use of learning curves can strengthen energy technology policy and provide some examples on how learning curves can be incorporated in long-term energy models.

Neij (1997) and Mackay and Probert (1998) have in particular addressed the prospects for diffusion and adoption of renewables. Renewables presently have a larger potential for cost reductions through technological progress than conventional technologies and could become the comparatively most cost efficient electricity generating technologies if they successfully continue to ride down the learning curves.

Figure 11.1,   shows the progress ratio estimated for costs of electricity generation versus

Figure 11.1 Left: Distribution of learning rates for energy technologies measured as $/kW vs. cumulative capacity (MW). Adapted from McDonald and Schrattenholzer (2000). Right: Cost reduction for electricity technologies in EU. Adapted from IEA (2000)

a) Distribution of learning rates
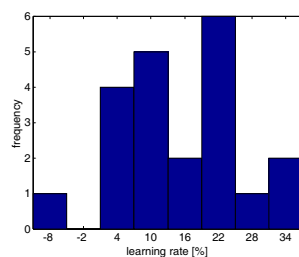
b) Cost vs.cumulative production
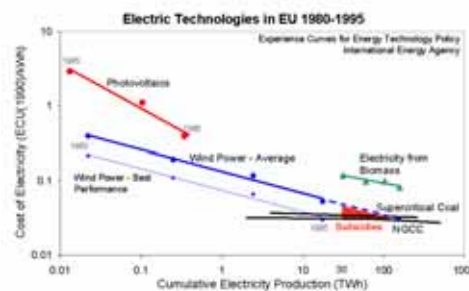
cumulative generation (IEA, 2000). However, there are considerable uncertainties underlying the learning curve. If learning curves are derived from list prices of generation technologies, profit margins, pricing strategies and external market conditions will influence the results (Extool 2003; IEA 2000). On the other hand, manufacturing costs are not readily available in the wind turbine market.

As an aggregated model, the learning curve does not reflect the more complex factors underlying technology development. For instance, knowledge and experience is embodied in

people and workers, who sometimes leave the industry for other jobs. In *Figure 11.1a,* some learning rates are negative, which can be explained by the exit rate of skilled people a sudden jump in external costs.

Finally, learning rates decline as technology matures and some models operate with different stages of the technology (Grubler and Nakicenovic, 1999).

11.3   Technology progress from a system dynamic point of view

Technology progress is the only major *reinforcing* loop in the system (see chapter page), whereas the other balancing loops oppose changes. Technologies tend to lock-in from technological progress. In a fully liberalised market, costs determine the choice of technologies. The balancing loops *resource depletion, capacity acquisition, generation scheduling and demand balance* are processes of *diminishing returns*, whereas the *learning curve* provides *increasing returns*.

Moxnes (1992) analysed the competition between "soft" (renewable) and "hard" (non-renewable) energy technologies using a system dynamic model involving technological progress market share and some stochasticity i.e. political decisions radical innovations etc. represented by random noise the relative attractiveness of the two technologies considered. The analysis shows that:
* Technological stimulus (i.e. subsidies) has a much larger impact than immediate responses of market shares
* If learning rates are not a priori known, the technologies with the most advantageous long-term potential (in terms of environmental characteristics, costs and resource availability) should be stimulated as the costs of correcting an erroneous choice is typically much higher than selecting the preferred one in the first place.
In our simplified model we have incorporated (additional to the technology progress) the resource availability and the short-term characteristics of capacity utilisation.

As mentioned in the previous section learning curves from empirical data can be misleading, as they do not recognise important underlying structures. Several system dynamic studies address such underlying sectors on company level such as allocation of resources to staff R&D marketing etc. at an organisational level.

An often referred work within energy policy is Watanabes (2000) econometric study of the PV development in Japan, in which the relationship between governmental subsidies, industry R&D spending, technology and technology progress was analysed. Watanabes study show how Government can identify and stimulate "virtuous cycles" of technology development.

Better understanding of R&D, technology progress and commercialisation is of importance for the design of efficient energy technology policies. Such modelling efforts involveintangibles such as knowledge and innovation for which system dynamics theory is well suited (Milling, 2002).

11.4   Technology progress in existing energy models

The decision support models EMPS and NordMod-T described in *Chapter 3* did not incorporate technology progress. MARKAL which is being used in Sweden for energy policy purposes (i.e. the Nordleden project and SOU 2001:77) and can in principle treat technology progress endogenously. Seebregts et al (1999) summarise the findings of including technology progress of the energy system models MARKAL, ERIS and MESSAGE.

The models are perfect foresight cost minimisation models solved by mixed integer programming (MIP). Technology progress is implemented as piecewise linear cost curves as

functions of cumulative capacity which makes the objective function non-convex. Their studies stress the importance of incorporating technology progress (rather than exogenous technology progress) as it has profound implications on the results and implications for energy policy making. The models become more consistent than if technological progress was exogenously represented (i.e. investments have to be made in order to make a technology cheaper). It was usually optimal to invest earlier in new technologies and large cost reductions could be obtained if CO_2 - targets was imposed. In fact stimulation of new technologies as also justified from a pure economic consideration.

Grubler et al. (1999) and Gritsevskyi and Nakicenovic (2000) report further enhancements of technological progress in the MESSAGE model by including uncertainty of the learning as well as the fact that uncertainty gradually decreases as the technology develops. Furthermore, several other factors such as the resource potential, minimum cost and demand were also treated as uncertain. By incorporating such uncertainty in the perfect foresight framework, diversification of investments in the technology portfolio took place in order to hedge risk. The options for new radical technologies lie in the long tails of these portfolios, and the opportunity of profits provides a rationale of investing in them.

The results yielded more realistic diffusion curves consistent with historical observations. Furthermore cost-optimal solutions were found in future energy systems with both high and low carbon-intensity.

The bottom-up modelling approach using data bases of a wide range of energy technologies combined with the stochastic description of several variables (stochastic nonlinear optimisation) required super computers.

Interestingly the insights gained from these modelling exercises are strikingly similar to the conclusions drawn from the simple model used by Moxnes (1992)[1]. Still, the models are simplified in many respects. The learning curves are based on investment costs without distinguishing between improvements in fuel efficiency and improvements in cost. A gas turbine can for instance exhibit an increase in unit costs per MW due to improvements of materials and design that increase its efficiency so that if measured in terms of energy output - costs are reduced.

While more complex relationships can easily be incorporated in a simulation framework it would become increasingly more difficult in an optimisation framework.

A benefit of the perfect foresight framework is that it provides an optimal solution among alternatives and hence a rationale to pursue one path of development. However, from the discussion in the theory chapter - given an optimal solution - it is not straightforward to implement this in practice when there is no single coordinating decision maker. Decisions are distributed. In this context implementation of a solution means designing market rules and regulations that would provide incentives for decision makers to produce the optimal trajectory suggested by the optimisation model. Ensuring such a development would require a detailed description of the behaviour of agents in the system, which is precisely what a system dynamics model does. A combination of the two modeling approaches seems beneficial: Optimisation models with perfect foresight assuming perfect market conditions provides a rationale for one course of development on the one hand, and on the other hand a simulation model that allows a detailed behavioural description of decision makers to assist in designing market rules and regulations to achieve the desired development.

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1. Compare Moxnes (1992) and Grübler et al. (1999).

11.5 Technology progress submodel

The detailed technology progress submodel includes all nine technologies considered. As a compromise, learning is represented by a weighted sum of both endogenous and exogenous learning. Endogenous learning represented by Eq. 11.3 follows the standard way of modeling learning as a function of cumulative capacity (see section 11.1). Exogenous learning rate is similarly represented by an exponential function $e^{(\text{exogenous learning rate} \cdot (t_0 - t))}$ where the exogenous learning rate is the fractional reduction in cost per year. *Table 11.1* shows the

Table 11.1 Endogenous Learning index and exogenous learning rates for technologies

	thermal					renewables			
	nu	co	ga	gc	gp	bi	hy	wi	wo
Fraction endogenous learning [1]	0	0	0	1	0	1	1	1	1
Learning index (endogenous) [1]	0	0	0	0.2	0	0.1	0	0.2	0.2
exogenous learning rate [1/yr]	0	0.004	0.005	0.014	0	0.008	0.002	0.014	0.014

assumed values of learning index, exogenous learning rates and weight on endogenous learning. In the *Technology progress* submodel (Eq. 11.1-Eq. 11.11), the user can specify the extent of exogenous versus endogenous learning for cost reduction (Eq. 11.3-Eq. 11.8). and corresponding learning effects on *resource efficiency* (Eq. 11.9-Eq. 11.11) displayed in *Figure 11.3*. The endogenous multiplier in Eq. 11.3 is a technology progress normalised to one at the start of the simulation. Investment costs are proportional with the technology multiplier as defined in Eq. 9.14, *Chapter 9*.

Technology progress $\forall \ i \in$ ***{gc bi hy wi wo}:***

11.1 *Cumulative capacity*$_{i,t}$ = *Cumulative capacity*$_{i,0}$ + $\int$ *investment rate*$_{i,t} \cdot dt$ *[TWh/yr]*

11.2 *Cumulative capacity*$_{i,0}$ = *Capacity*$_{i,0}$ *[TWh/yr]*

11.3 *endogenous learning multiplier*$_i$ = (Cumulative capacity$_i$ / Capacity$_{i,0}$)$^{\text{Learning index}_i}$ *[1]*

11.4 *Learning index*$_i$ = [0.2 0.2 0 0.2 0.2] $\forall \ i \in${gc bi hy wi wo} *[1]*

11.5 *Weight on endogenous learning*$_i$ = [0 0 0 1 0 1 1 1 1] *[1]*

11.6 *exogenous learning multiplier*$_i$ = *exp(exogenous learning rate*$\cdot(t_0 - t))$

11.7 *exogenous learning rate* = [0 0 0.005 0.014 0 0.002 0.008 .014 0.014] *[1]*

11.8 *learning multiplier*$_i$ = *endogenous learning multiplier*$_i \cdot$ *Endogenous learning fraction*$_i$ + *exogenous learning multiplier*$_i \cdot$ *(1-Weight on endogenous learning*$_i$) *[1]*

11.9 *resource efficiency*$_i$ = *exogenous learning multiplier* *[1]*

11.10 *Initial resource efficiency*$_i$ = [0.35 0.45 0.58 0.45 0.3 1 0.32 1 1] *[1]*

11.11 *exogenous learning multiplier*$_t$ = *// see time graph in Figure 11.3* *[1]*

Figure 11.2 SFD technology progress
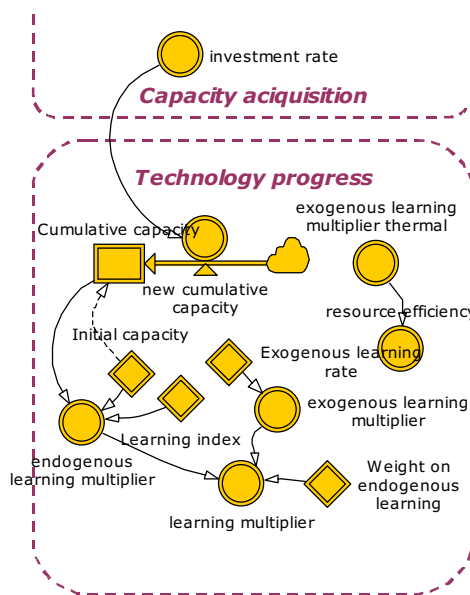
Representing learning in a local area is problematic as manufacturers participate in international markets. National and regional energy analysis usually assumes exogenous technology progress, while global models can endogenously capture technology progress. However some learning requires local markets as was the case of wind power in Denmark. Close collaboration and relations with customers, competitors and suppliers provide favourable environments for learning (Karnøe, 1992). Some technologies also require local adaptations.

Figure 11.3 Exogenous specified development in conversion efficiency. Hydro and wind and offshore wind are normalised relative to year 2000. (efficiency index=1), whereas the other efficiencies represent conversion efficiency.
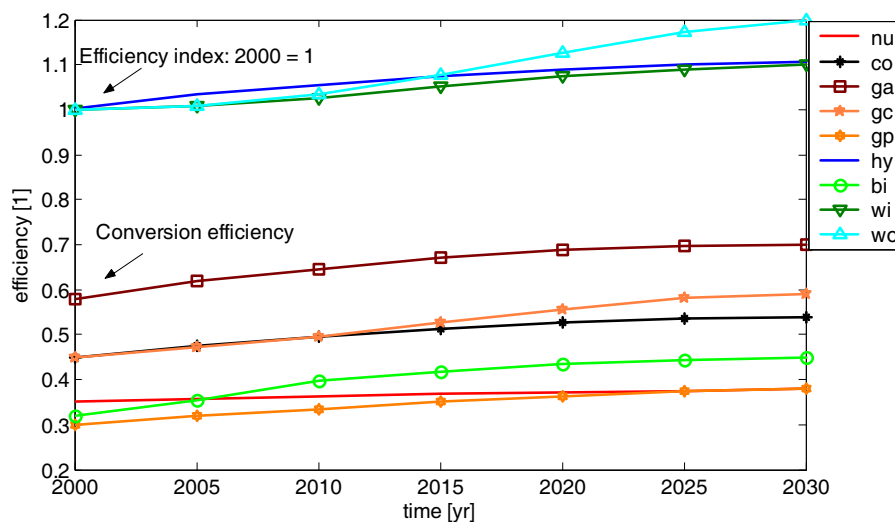
Since Danish manufacturers have kept 50% of market share worldwide and enjoys a strong position in both within industry, research and site development - arguments can be made that the development of wind power in the Nordic countries where resources are highly attractive is a major determinant to the technology progress wind power. Suitable shallow offshore areas are in the vicinity of Danish waters. Sweden, Germany, the Netherlands and UK in addition to Denmark have all launched projects for offshore wind power. Development of Danish offshore wind parks are by Danish industry and authorities considered to be of major importance in order to keep their competitive advantage on the international market.

If the supporting climate for wind power should fail in the Nordic countries Danish wind power industry can still rely on the international market as was done in the eighties participating in the "Californian wind rush" while suffering from lack of domestic support.

In the model an exogenous learning rate is also provided so that the user can specify to which extent effects of "local learning" should attribute technology progress.

Nuclear coal and gas are technologies that have matured. Gas power shows further cost reductions, and the technology grows worldwide by 15% enabling further progress. Coal on the other hand is less attractive for environmental reasons and there are few opportunities for further cost reductions if we are to judge from the historical experience curves.

In the same way as Denmark is at the cutting edge of wind power, Sweden Finland and Denmark are highly competitive within electricity generation from biomass. The Danish Energy Act (Energy 21), which for a long period governed Danish energy policy ensured stable conditions and targets for development of wind biomass.

Finland and Sweden stands out with a relatively high share of electricity generation from biomass thanks to the larger paper and pulp industry. However the pulp industry has not yet taken full advantage of utilising integrated production of heat and electricity using their waste residues and the newly introduced TGC arrangement can release some of the potential[1]. Nor-

way on the other hand, has to a limited extent made use of CHP due to the historically low prices of electricity from hydropower. With harmonisation of the Nordic electricity market, utilisation of CHP should become more attractive in Norway as well.

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12 Resource depletion
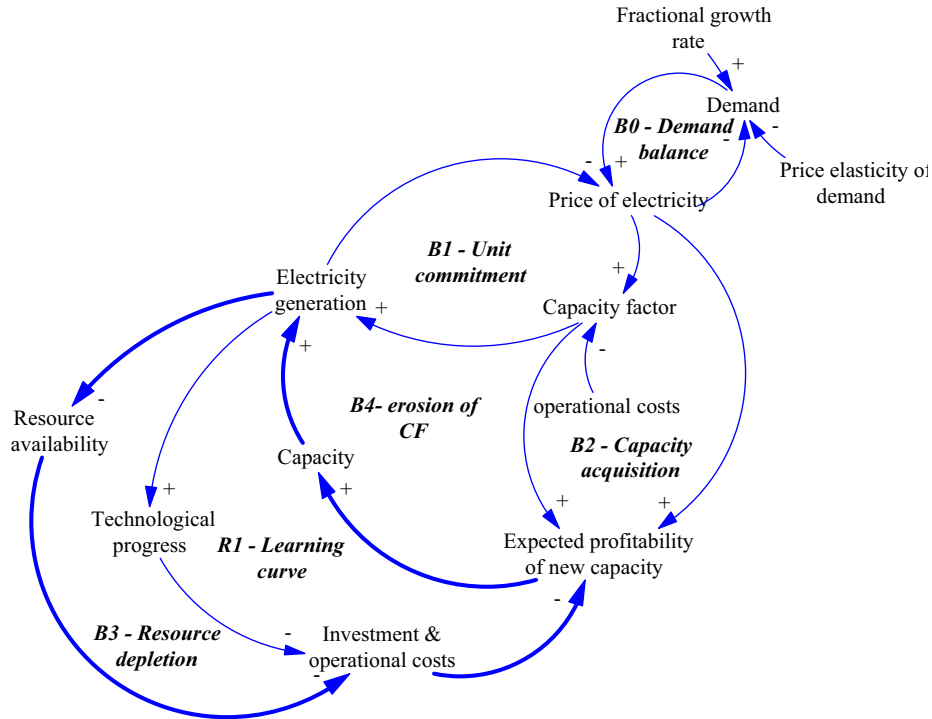
E ach technology will ultimately reach limits of resource availability as the balancing loop *B3 -resource depletion* loop in the above diagram illustrates. As resources become scarce the costs of developing projects from the remaining resource base increase, which will reduce the profitability of subsequent projects.

In this chapter, we will explore the resource potential for each of the technologies considered. The resource potential is mainly extracted from REBUS (Renewable Energy Burden Sharing) - a recent EU-project that analysed the potential benefit of jointly achieving each countries renewables target. Based on these data, aggregated costs curves measured as resource potential in GWh versus costs were established. The sensitivity analysis in section 5.7 showed that the share of generation is sensitive to the resource availability while the electricity prices are less sensitive.

In the following sections, we will critically examine, hydropower resources, wind, and biomass in the REBUS data and compare with other sources of information.

12.1   Resource estimates

REBUS (2001) recently mapped the available renewable resources within EU and the costs of developing these resources. They define *Technical potential* as the potential in GWh that can be extracted by utilising existing renewable technologies wherever possible subject to some assumptions on available land (wind) and material (biomass). The definition *Realistic potential*, consider some additional subjective constraints on public and institutional barriers and environmental concerns.

We use the REBUS database here as our main source, but complemented with other sources of information from national institutes in Denmark, Sweden, Finland and Norway

when relevant. Some of the resource estimates are uncertain, but the assumptions for resource availability can easily be modified whenever better information becomes available.

12.2 Hydropower resources

Hydropower has practically reached its potential though these limits are to some extent politically and economically determined. Further expansions must come from small-scale development. Fairly comprehensive and good overviews of remaining hydropower resources exist for larger projects.

Figure 12.1 Costs of new hydropower development in Norway. (Source : NVE)
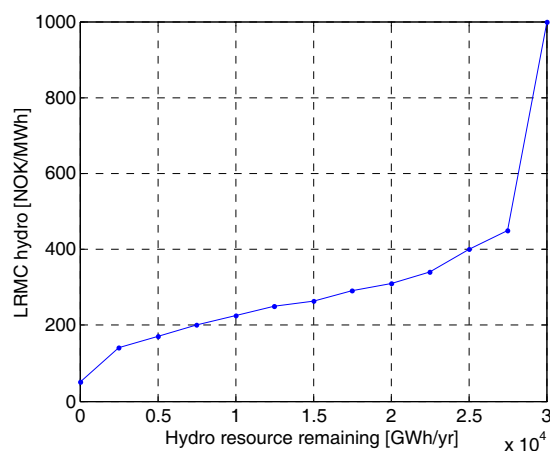
Figure 12.1 shows the costs of remaining hydro resources in Norway. The curve includes resources applicable for permits, including upgrades and expansion of existing hydropower stations.

Remaining hydropower potential in Sweden is 8.5 TWh/yr (SOU 77:2001). The estimate contains 2.5 TWh small-scale hydropower[1], larger[2] resources amounting to 5 TWh, and 1 TWh from upgrading,. These cost estimates are in the range 350-450 SEK/MWh[3]. Norway and secondly Sweden possess the main share of hydro resources, though some resource po-

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1. Mainly restoration of old plants and new hydropower in watercourses
2. >1.5MW
3. Assuming 8% interest rate 40 years lifetime according to SOU 2001:77 p169

tential also exist in Finland. *Figure 12.2* presents REBUS data of hydropower resources for

Figure 12.2 Hydropower potential technical and realistic according to REBUS. Norwegian potential according to NVE. Current hydropower generation indicated by arrows[1].
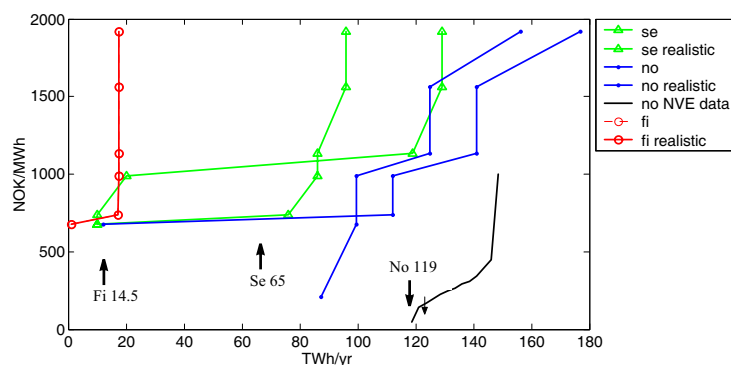
1. Costs converted from european currency, 8 NOK = 1 € (2000)

the Nordic countries, where arrows indicate the current generation level for each country. Both technical and realistic potentials are shown For comparison, the remaining potential (added to the developed hydro resources in Norway) is also plotted (solid line at the lower right).

The REBUS cost estimates seem too high compared to data from NVE and the Swedish SOU report[1], which we consider the latter two data sources to be more reliable.

We therefore make the choice of using the Norwegian NVE data as a proxy of remaining hydropower potential. The curve can also be scaled up to include the additional hydro resources in Sweden of 8.5 TWh/yr.

12.3 Wind resources

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 must take place offshore or by upgrading old sites. Replacing old turbines with the new and larger ones can still increase their capacity from 3000 to 5000 MW.

At present the energy costs of developing offshore parks are 30-40% higher than for onshore. In contrast, the offshore potential is practically unlimited and can thus serve as a backstop technology if cost levels are brought sufficiently down.

The coastal areas of Norway provide good opportunities for cheap and cost-effective wind power onshore, and NVE[2] recently made a wind resource assessment

As the more windy areas are utilised first, remaining areas are less attractive. The historical trend from Denmark shows that cost reduction from technological progress has dominat-

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1. SOU 77:2001
2. See Vector: www.vector.no

ed over cost increases from less attractive areas, and these two mechanisms are endogenous through the *learning curve effect* (loop R1) and the *resource depletion (loop B3)*.

Norway is best suited for onshore development, and the ongoing harmonisation of energy and environmental policies (i.e. Tradable green certificates in *Chapter 16*) within the Nordic market can provide a continued and potentially more cost-effective development.

Figure 12.3 Renewable wind potential (adapted from REBUS). Middle graph shows current wind generation for Denmark and Germany (location on y-axis indicate the unit price paid to turbine owners). The lower graph shows total potential for the Nordic countries both realistic and technical.
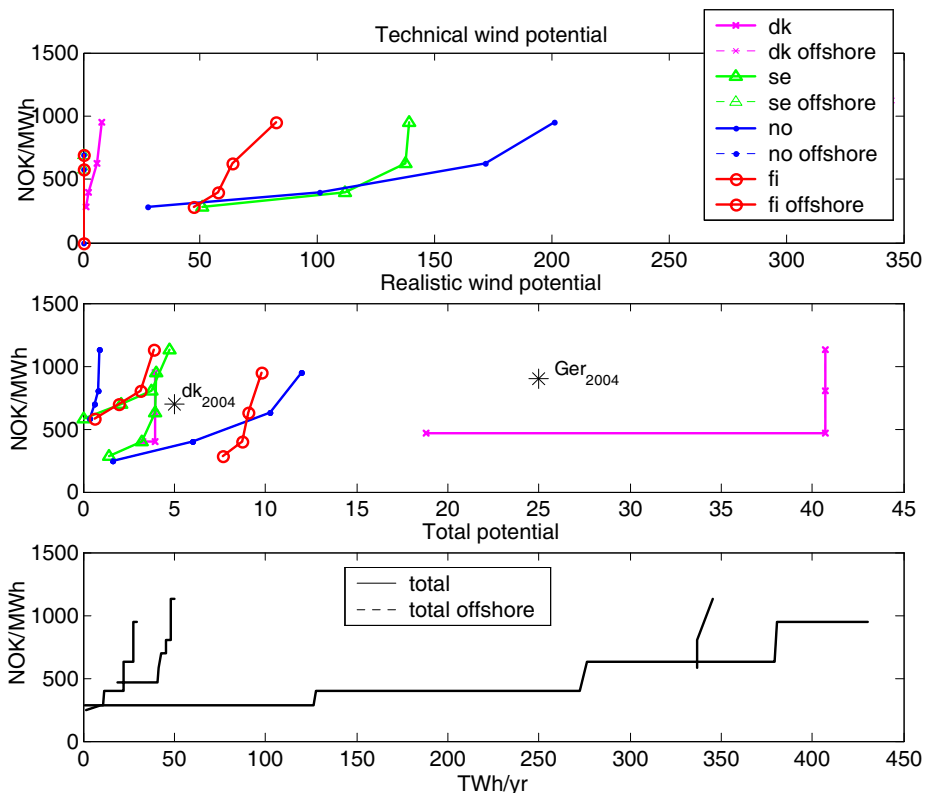
Figure 12.3 shows the wind resource potential for each of the Nordic countries according to REBUS. Inspecting the onshore technical potential, Norway has the largest potential but the data also shows that some of the most windy onshore resources are present in Sweden and Finland. It is doubtful that more attractive resources exist in Sweden and Finland than along the Norwegian coast.

Let us compare with Germany when evaluating the *realistic potential* for Norway and the other Nordic countries. The four upper Bundesländer comprise 40% of the total German land area ($357\,000$ km^2) from which 11000 of in total 14600 MW capacity has been installed (Jan. 2004). Germany is comparable in size with Norway ($324\,000$ km^2). If the same amount of capacity is installed in Norway (assuming 3000 full load hours), electricity generation

would amount to 34 TWh/yr, which is three times the indicated potential by REBUS for Norway.

From these comparisons, the Norwegian realistic wind power potential seems underestimated. REBUS gives a higher resource estimate for Sweden and Finland, in line with the German present situation[1].

A recent study from NVE (2003) of selected stretches along the Norwegian coastline covering 12% of mainland shows a large *technical potential* of 1189 TWh/yr when assuming a density of 15 MW/km2. The same study reports an offshore potential in the same area, up to 50 m depth to be 829 TWh/yr[2].

From the above discussions and comparisons, the REBUS data must be used with caution. Some of the estimates seem too low or inconsistent with other sources of information.

Offshore technical potential estimates for Denmark are very high for (~350 TWh), while there is no other real estimates for the other Nordic countries in the REBUS data. *Figure 12.3*, lower graphs show the realistic potential for wind. The realistic onshore potential exceeds the technical potential estimate for Denmark, which indicate some inconsistency of the data set. The realistic potential for Denmark onshore is set to current level of generation around 4.5 TWh/yr. This level of generation is already surpassed. Realistic offshore potential is only estimated for Denmark (40 TWh/yr), but all Nordic countries are in possession of offshore potential. Several offshore parks are at the planning stage in the shallow coastal areas of Sweden.

The below graph express the wind resource potential onshore in terms of full load hours as a function of utilised resources. The right most curves represent an aggregate for the Nordic countries, the curves to the left represent each country. The approximations are summarised in *Table 12.1*. The resource potential for Denmark was upscaled from present utilisation of 5 TWh/yr up to 8 TWh/yr in accordance with realistic potential estimates from the REBUS data. The curve shape for Sweden and Finland has also been determined from the REBUS data but the realistic potential is aligned with the development in Germany.

Finland and Sweden is in area comparable to Germany. Assuming 2000 full load hours against 1700 in Germany, the countries would, if the *present* capacity in Germany is installed in Sweden and Finland, amount to 40 and 30 TWh/yr respectively[3].

The curve for Norway is estimated from the NVE study. A realistic resource potential of 100 TWh/yr is then assumed (3000 full load hours) justified by the sparsely populated areas and the high average wind speeds along the Northern Atlantic coast.

Table 12.1 Wind resource assumptions. The distributions for each country are based on REBUS data for Norway - NVE data is used. For assumed total potential, see above discussion. (- indicates no estimates available)

wind speed	flh	fractional distribution of total resource				tot
[m/s]	[hr/yr]	dk	fi	no	se	[TWh/yr]
>9	4000	-	-	0.13	-	13
>8	3500	-	-	0.38	-	38
>7	2800	0.16	0.58	0.75	0.36	108
>6	2000	0.32	0.70	1	0.8	155

1. ReBUS uses a density of 35 kW/km2. The density in the four upper Bundesländer is 75 kW/km2, comparable to the density of wind turbines in Denmark
2. For depths <10 m, 181 TWh/yr was reported
3. adjusted for the relative difference in land area

Table 12.1 Wind resource assumptions. The distributions for each country are based on REBUS data for Norway - NVE data is used. For assumed total potential, see above discussion. (- indicates no estimates available)

wind speed	flh	fractional distribution of total resource				tot
[m/s]	[hr/yr]	dk	fi	no	se	[TWh/yr]
>5	1000	0.78	0.77	-	0.99	167
>4	0	1	1	-	1	175
Total resource	**[TWh/yr]**	**8**	**30**	**100**	**40**	**178**

Figure 12.4 Full load hours for onshore wind as a function of resource utilisation

a) Full load hours as a function of resource utilisation corresponding to *Table 12.1*
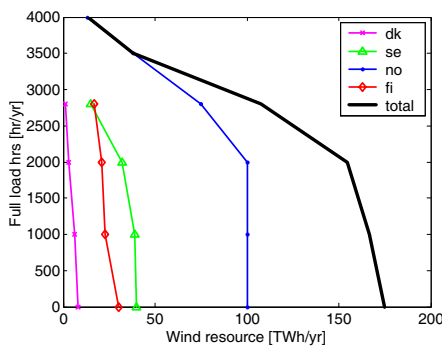
b) Full load hours versus normalised resource utilisation: *Effect of resource on flh wind*.
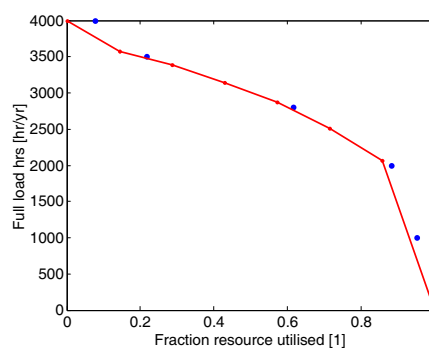
Recent development within wind power industry aims at developing the offshore potential. In Denmark new developments takes place offshore, and Sweden, UK, Germany and the Netherlands are now developing offshore wind parks. The disadvantage of offshore wind parks comparable to onshore is the higher costs of foundations and site development.   The costs are approximately 30-40% higher than for onshore wind turbines, while the technical potential is in practice unlimited.

In the REBUS project, offshore potential for Denmark is identified to 40 TWh/yr. The offshore potential in the NVE study is in the same magnitude as the onshore potential as the potential was here identified for some selected areas along the coastline. The realistic potential offshore (not considering costs) is therefore also substantial in Norway but cheaper alternatives onshore makes offshore alternatives less attractive until these are fully exploited or the cost reductions for offshore wind technology are brought further down.

For our purpose, we assume full load hours of offshore wind parks to be almost *independent* of the resource utilisation and we thus keep offshore full load hours a constant at 3500 hr/yr.

Others have even begun exploring the possibilities for floating offshore wind power. Norsk Hydro started a concept study for deep-water offshore wind turbines[1] where the cost estimates indicated feasibility of the projects. However, serious challenges are expected for integrated dynamic analysis of structural loads from wind and waves. Potential advantages

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1. Presentation held at Wind Power Colloquium 09.03.2004 NTNU. See www.bygg.ntnu.no/vindkraft/.. ?

of floating offshore versus shallow offshore turbines are higher wind speeds, and possibly lower erection costs.

12.4 Bioenergy resource potential

Scandinavia is largely covered by pine and spruce trees having paper and pulp industry among the larger industries. Different kinds of waste from the pulp industry and building materials from wood provide cheap sources of biomass for heat and electricity cogeneration in Sweden and Finland. The available potential is estimated to be about 100 TWh/yr (for electricity generation) 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. *Figure 12.5* shows the REBUS data for bioenergy resource potential in the Nordic coun-

Figure 12.5 **Bioenergy resource potential for electricity generation (adapted from REBUS, 2001)**
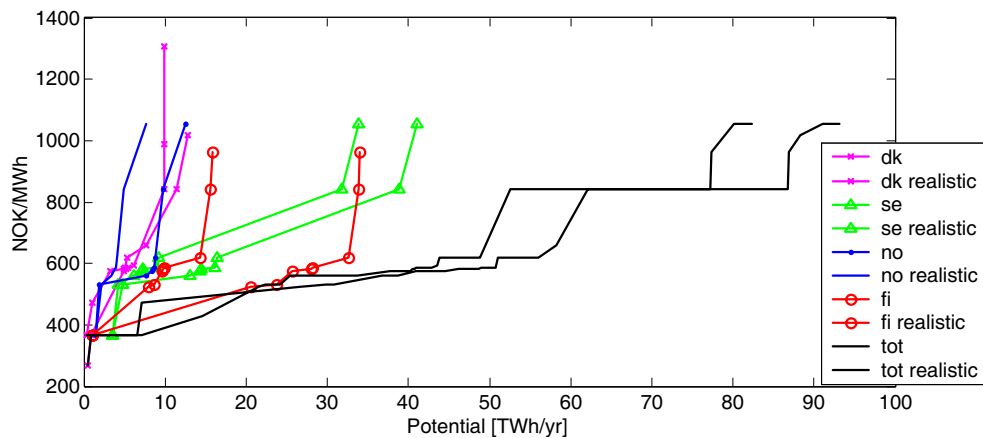
tries.

Technical and realistic potential do not differ much. As expected, the Swedish and Finnish bioenergy potential are the largest ones. Denmark's resource base comes mainly from the agricultural sector. In this overview, the realistic Swedish potential is larger than the technical potential, which is inconsistent. The normalised curve shown in *Figure 12.6* corresponds to total potential in *Figure 12.5*. The total supply curve is normalised to represent the fuel

costs of renewables, where the level of generation from bio in 2000 and the associated costs were used[1].

Figure 12.6 Normalised bio resource fuel costs based on REBUS data (18.5 TWh 502 NOK/MWh)
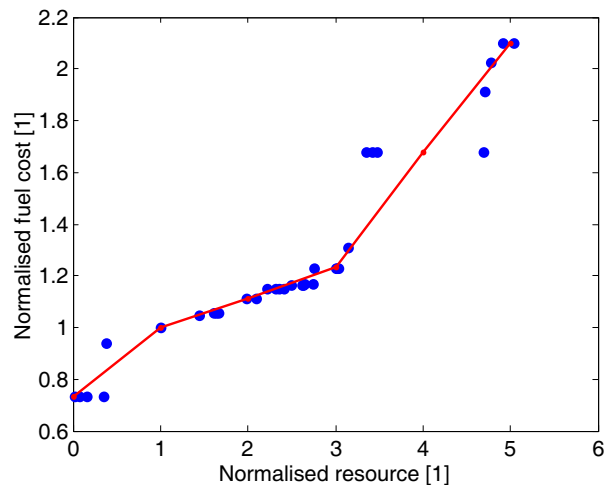
12.5   Representing resource availability Kraftsim

We represent the constraining resource availability of *hydro*, *bio* and *wind* in *Figure 12.7*. using the three corresponding tabulated relationships from section 12.2-12.4. The resource usage fraction of each technology *i* in Eq. 12.1 is input to the corresponding table function Eq. 12.2-12.4.

The effect of resource on costs hy gives the energy costs in [NOK/MWh] of the next remaining hydropower project, whereas *effect of resource on costs bi* is a multiplier normalised to the current cost level of biofuel.   Finally, *Full load hrs wi* gives the number of full load hours for new onshore wind generation.

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1.   The benefit of normalising tabulated data, is that changes in reference values can be made without the need to alter all the table values. This is useful for scenario- and sensitivity analyses

Figure 12.7 SFD diagram Resource availability submodel. (Double-edged symbols indicate vectors)
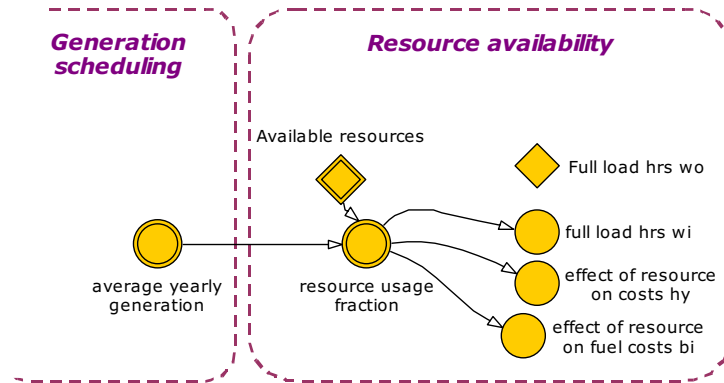
Resource depletion submodel $\forall$ ***i*** $\in$ ***{hy, bi, wi}:***

12.1   resource usage fraction$_i$ =average yearly generation$_i$/Available resources$_i$ [1]

12.2   effect of resource on cost$_{hy}$ = GRAPH(resource usage fraction$_{hy}$, 1,2.5/200 {50 140 170 200 225 250 265 290 310 340 400 450 1000})   [NOK/MWh]

12.3   effect of resource on fuel costs$_{bi}$ = GRAPH(resource usage fraction$_{bi}$,1,{0.73 1 1.11 1.23 1.68 2.10})   [1]

12.4   full load hrs$_{wi}$ = GRAPH(resource usage fraction$_{wi}$,0.1,{3990 3570 3390 3140 2870 2510 2060 0}   [hr/yr]

Since the offshore wind power costs is large, the number of full load hours of offshore wind power is independent of resource utilisation:

12.5   Full load hrs$_{wo}$ = 3500   *[hr/yr]*

12.6   Fossil fuels and nuclear

Due to the large gas reserves 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.

Since gas is the most competitive source of generation at present, it is setting the long-term price of electricity in the market, and the model will therefore be sensitive to the gas prices, which is dependent on the demand of gas in Europe, the supply, and the supply line (i.e. infrastructure). The dynamics of gas reserves have been analysed for the US (Sterman and Davidsen). In a recent study using LIEBMOD[1], Sagen and Aune (2004), recently concluded that European gas prices in the long term (2010) most likely would remain above 80 øre/Sm3 .

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1. Liebmod is a numerical, partial equilibrium model of European energy markets.

Gas prices depend on the demand, price of substitutes and the supply of other producers to Europe (Russia, Algeria), and supply from LNG. We take gas price as exogenous in our model. It is outside the scope of this thesis to include the market for gas. Nevertheless, a large expansion of gas power will necessarily feed back on the gas price in the Nordic countries, for which the electricity market price is sensitive.

The cost of nuclear fuel is also considered conststant over time. Other factors such as safe deposition, transport and storage is considered more important for the overall costs. For nuclear technology, the capital costs are the most important one along with public acceptance.

Fuel price submodel $\forall \, i \in \mathrm{T}$

12.6   Fuel price

12.7   Fuel price$_{co}$ = 0.3   *[NOK/kg]*

12.8   Fuel price$_i$ = 90 $\forall \, i \in$ {ga,gc,gp}   *[øre/Sm^3]*

12.9   Fuel price$_{bi}$ = 0.3·effect of resource on fuel costs bi   *[NOK/kg]*

12.10 Fuel costs$_{nu}$ = 22.75   *[NOK/MWh]*

12.11 Fuel costs$_i$=0 $\forall i \in$ {hy, wi, wo}   *[NOK/MWh]*

12.12 heat value$_{co}$ = 7.8   *[kWh/kg]*

12.13 heat value$_i$ = 11.6 $\forall \, i \in$ {ga,gc,gp}   *[kg/Sm^3]*

12.14 heat value$_{bi}$ = 4.3   *[kWh/kg]*

Fuel price$_{bi}$ is endogenous in our model. The *effect of resource on fuel costs bi* multiplier in Eq. 12.2 links *Fuel price$_{bi}$* with the resource availability of biomass described in Eq. 12.9.

12.7   References

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13 Demand
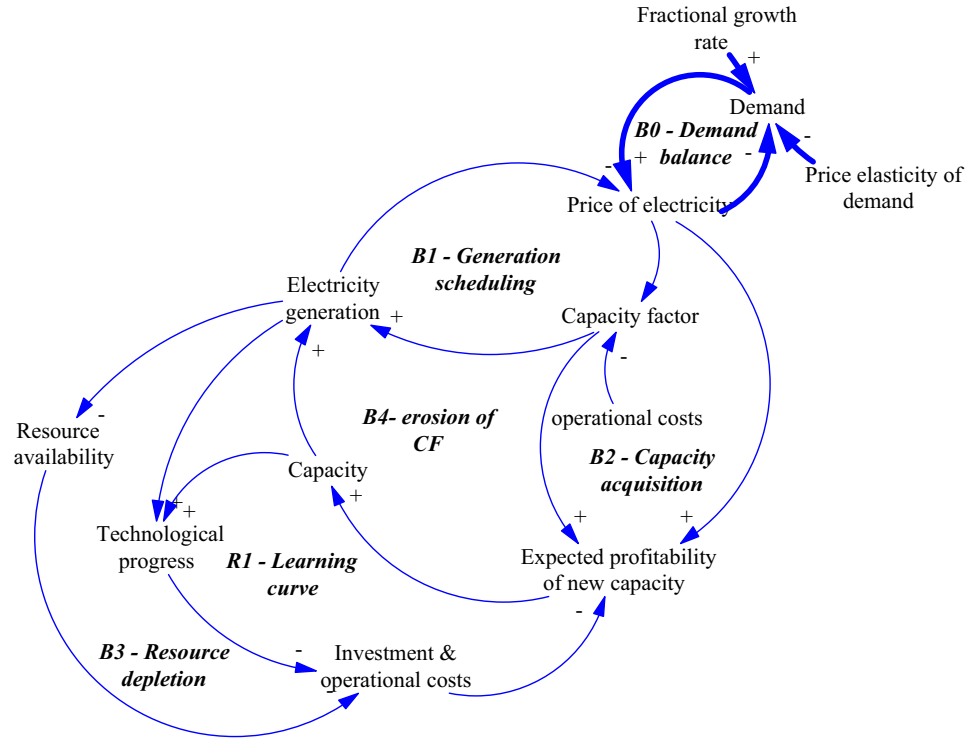
The demand side is kept fairly simple in our model as the main focus is on the supply side, though there are many interesting demand side alternatives to the development of new capacity on the supply side. As a compromise, we try to capture some of the main characteristics of the demand side: *Demand variations*, *demand growth* and *price elasticity of demand*.

Prior to market deregulation, focus has been on supply side, as the challenge for the utilities were to supply electricity demand at acceptable prices. Customers did not have the freedom to choose suppliers, and there were few incentives for utilities to look to the demand side to find alternatives to grid and capacity expansion. With deregulation and economic incentives for distribution companies to increase efficiency, this has now changed. In the following we will point out some likely developments of demand within a deregulated electricity market before we describe the demand side in our model.

13.1 Demand in a deregulated market

The current centralised power system has not been shaped under market forces and the utility industry has been mainly protected from competition. The deregulation can trigger new technologies and arrangements on the demand side, in particular options for load flexibility.

Electricity prices separated from transmission and distribution costs have made investments on the supply side increasingly more attractive. Current costs of electricity generation

and distribution shows that the costs are approximately divided to one third of each generation, transmission/distribution and taxes. This means that initiatives to reduce demand not only save costs of electricity, but also costs of transmission, distribution and taxes.

The high degree of variation in electricity prices makes measures for flexible load management more attractive, resulting in increased short-term price elasticities that can shift electricity demand to periods of low prices. Long-term price elasticities indicates the willingness to reduce energy consumption over a longer period through investments (i.e. insulation, heat pumps), or through change of habits. It is likely that electricity consumption in the future will be measured on an hourly basis, enabling more flexible load management systems at the end-user and thus increased short-term price elasticity. Several pilot projects are now carried out with a focus on end-user load management, such as the EU-project EFFLOCOM (Energy EF-Ficiency and Load curve impacts of COMmercial development in competitive markets), and projects by SINTEF (Grande et al., 2002; Hunnes and Grande, 2002)

The energy intensive industry in Norway has enjoyed hydropower at favourable prices, and many of these long-term contracts will expire towards 2010. A re-negotiation of such favorable contracts is unlikely. While subject to international competition, the consequence of higher electricity prices to this industry has not yet been addressed. Some industries probably relocate to low-cost countries. In Finland, however, electricity demand in industry is expected to rise significantly. Such structural changes can influence electricity demand as well as the demand profile and the price elasticity of demand. We expect the total electricity demand to be increasing, mostly due to economic growth. Exogenous drivers are population- and economic growth and a continued trend towards more electricity based energy consumption[1] (Nakicenovic, 1999).

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1. In Norway however, electricity has been in extensive use also for heating purposes, and an opposite trend is here more likely.

Figure 13.1 Demand hour by hour in Nordic market - 2001. (Source : Nordpool)
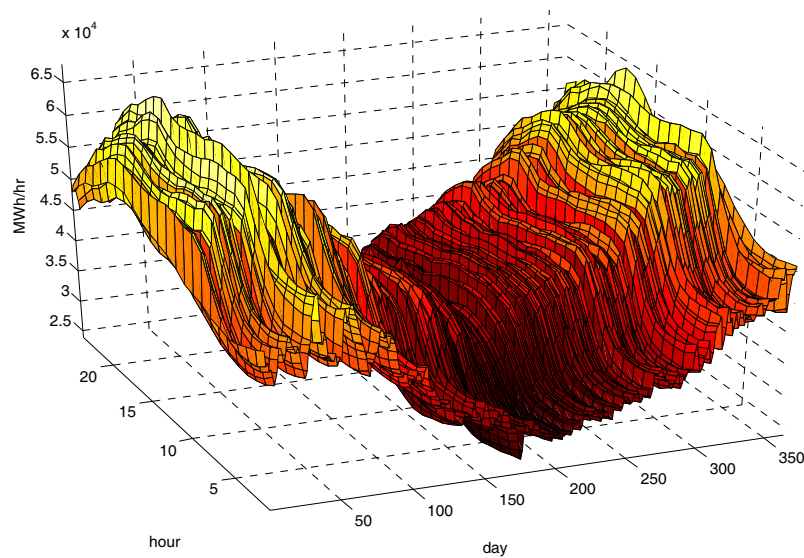
13.2   Model representation of demand

There is (still) few feedback loops between the demand side and the supply side. Main feedback is the price, which is described through the price elasticity of demand. Future development in electricity demand is represented exogenously at a fixed growth rate. An endogenous representation would require a representation of the Nordic economy, which is beyond the scope of this thesis. Models that do represent the economy (such as MSG-6 for Norway or Adam for Denmark) can be linked to the system dynamic model, as is done with Nordmod-T and MSG-6 (Johnsen, 1997) or in the Danish case the linkage between ADAM and EMMA (Karlsson, 2002).

Figure 13.1 shows the hourly demand profile for Nord Pool in 2001[1], where days and hours are plotted along separate axes. A closer inspection shows that seasonal demand variation is significant, followed by hourly load variation. We can also identify some weekly variation. These load characteristics are, of course, subject to change during the 30-years simulation period, but it is still likely that the shape of seasonal variation as well as daily variation remains. Load patterns can be modified from industry towards service-based economy; changes of working days, and use of electricity in the transport sector (i.e. hydrogen and electrical vehicles), but these are long-term changes that should be considered exogenous to our model. Increased load flexibility however, may be one of the major responses to deregulation, for which some fraction of daily load can be redistributed to hours of lower prices.

---

1. Source: Nord Pool. Data available through ftp-server at www.nordpool.no

Figure 13.2 Demand submodel. Underlying growth and price elasticity of demand represent end-user behaviour. The end-user slowly adapts to new prices

a)
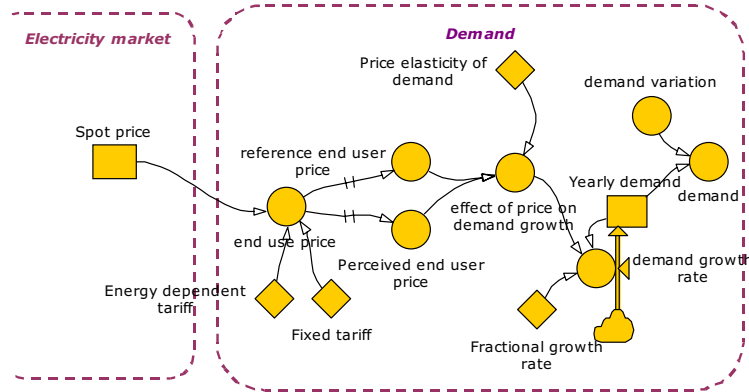
Demand representation is here summarised by *growth in electricity demand*, the *price elasticity of demand* (both in the short term and the long term) and the *demand variation* within the day, week and season. Eq. defines the demand submodel corresponding to *Figure 13.2*.

Demand submodel

13.1   *demand = Yearly demand · demand variation*   [TWh/yr]

13.2   *Yearly demand$_t$ = Yearly demand$_0$ + ∫ demand growth rate$_t$ · dt*   [TWh/yr]

13.3   *Yearly demand$_0$ = 385*   [TWh/yr]

13.4   *demand growth rate$_t$ = Yearly demand· (Fractional growth rate + effect of price on demand growth)*   [TWh/yr^2]

13.5   *Fractional growth rate = 0.012*   [1/yr]

13.6   *effect of price on demand growth = (Perceived end user price / Reference end user price)$^{Price\ elasticity\ of\ demand}$*   [%/yr]

13.7   *Reference end user price = DELAYINF(end user price,5 yr)*   [NOK/MWh]

13.8   *Perceived end user price = DELAYINF(end user price,1 yr)*   [NOK/MWh]

13.9   *Price elasticity of demand = -0.3*   [1/yr]

13.10 *end user price = Spot price + Energy dependent tariff + Fixed tariff*   [NOK/MWh]

13.11   *demand variation = GRAPHCURVE(time,0 wk,1 wk,{0.023 0.022 0.024 0.023 0.023 0.025 0.022 0.022 0.025 0.023 0.021 0.022 0.022 0.020 0.019 0.019 0.019 0.017 0.016 0.016 0.016 0.016 0.016 0.016 0.015 0.014 0.015 0.014 0.014 0.013 0.014 0.015 0.015 0.015 0.016 0.016 0.016 0.016 0.017 0.018 0.017 0.017 0.019 0.019 0.020 0.021 0.021 0.022 0.022 0.022 0.023 0.022 0.023}) · 52 wk/yr*   [1]

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.

Demand is modelled using a Cobb-Douglas function in *Demand submodel equation set* with a price elasticity of demand equal to -0.3 on a yearly basis although the reported estimates vary from -0.2 to -0.8 (NOU 1998 p99; Econ 1999 p11; Groenheit and Larsen, 2001 p46). Simulating over 30 years, demand and price elasticities will change significantly. It is beyond the scope of this model to address long-term changes in consumption.

Demand is composed of two factors; Yearly demand and demand variation. The time resolution of demand variation can represent monthly, weekly or hourly resolution. The reference run contains weekly resolution (or monthly). In Eq. 13.11, a weekly resolution is represented.

The underlying yearly demand is represented as a level with a net growth rate composed of the sum of an exogenous growth rate at 1.2 % per year, a fractional demand rate due to the (yearly) price elasticity of demand. In the Cobb-douglas formulation (Eq. 13.6), the consumers compare the last years average end user price with the *Reference end user price*, which is an adaptive expectation of the last five years end user price. This formulation is motivated from cognitive psychology, where heuristics such as anchor-and adjust rules are used in decision-making. (Sterman, 2000; Hogarth 1987). We adapt slowly to price levels, while sudden jumps in prices draws immediate attention irrespective of whether the price changes can be considered fair and reasonable.

The price elasticity of demand is measured on a yearly basis, so the elasticity represents the aggregate of investment decisions and other measures that will reduce electricity demand in the long run. A short-run price elasticity of demand can also be formulated, which takes into account the flexibility to reduce consumption on a short notice when prices are high :

13.12 *Daily avg price = DELAYINF(Price,7 da)* [NOK/MWh]

13.13 *daily fractional change in price = (Price - Daily avg price)/Daily avg price* [1]

13.14 *effect of short term price on demand = daily fractional change in price·Short term elasticity of demand* [1/da]

13.15 *Short term elasticity of demand = -0.2* [1/da]

Eq. 13.4 must also be changed to :

13.16 *demand growth rate$_t$ = Yearly demand·(Fractional growth rate + effect of price on demand growth + effect of short term price on demand)* [TWh/yr^2]

and the load variation curve in Eq. 13.11 must be substituted with one containing daily patterns.

13.3 References

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SSB : MSG-6

14 Simulation runs

T his chapter provides a small sample of various simulations runs to show the model behaviour and how it can be used to test the response of new policies. In the "reference" simulation run we provide an interpretation of the simulation run, showing the main aspects of the model behaviour. The subsequent runs show some selected responses to policies. The variables showing yearly averages need the first year (2000-2001) to compute the average level, and some of the graphs here will exhibit a 'dip' in during the first year.

14.1 Reference run

In the reference scenario, we assume 100 NOK/MWh in subsidies for renewables, but no CO2-taxes. *Figure 14.1* shows capacity development for the various technologies. 25% of potential new nuclear capacity is rejected. All other plant types get approval. Demand grows at 1.5%/yr, with a price elasticity of -0.3, which is a bit more than the previous observed elasticity of about -0.2 per year. This is because we assume development of a more flexible demand side in the future.

Nuclear and coal declines, while gas and onshore wind are the winners. We can also observe that no large investments take place in the first decade, from 2000 to 2010. The first years are characterised by overcapacity.

Figure 14.1 Capacity development and demand
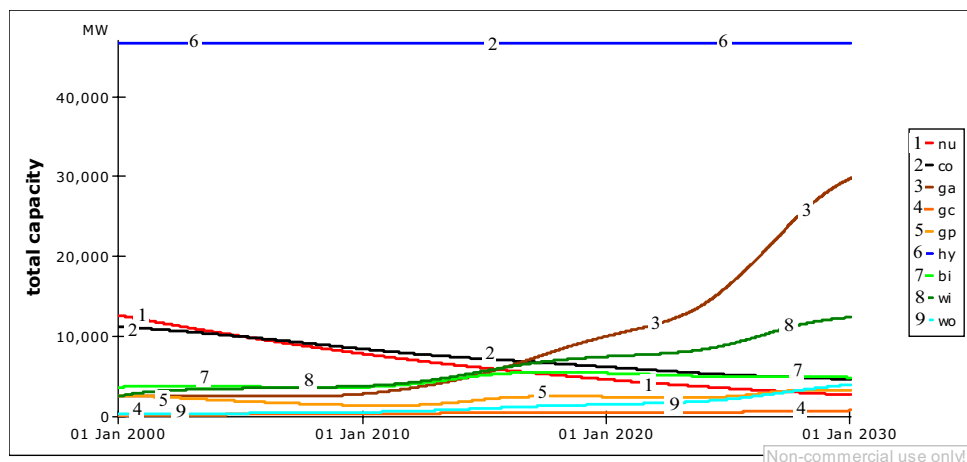
Prices are on the rise as demand increase, and old capacity is phased out without being compensated by new investments. As shown in *Figure 14.2*, prices continue to rise until prices stimulate new investments that come on line after the first decade (2010). Capacity acquisition is afflicted with long time delays, which results in long-term fluctuations around a trend defined by the long-run marginal cost of the cheapest available technology. The cheapest available technology is gas power in the beginning, whereas wind power takes over this position towards the end of the simulation, if the subsidies are included for (which is the case for investment decisions in this simulation run). Gas prices are constant throughout the simulation period.

Figure 14.2 Price development. Thin line shows price with seasonal variation, bold line shows average price.
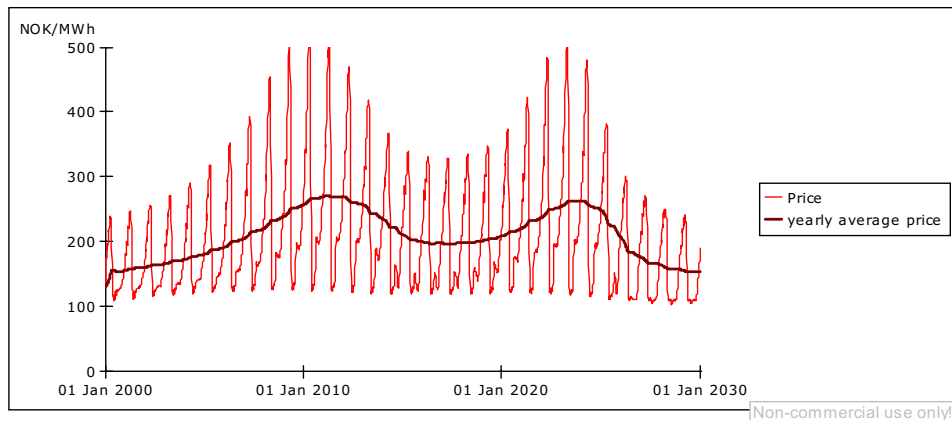
The price scenario can thus be divided into two phases. The current phase is a phase of price increase towards the long-run equilibrium. In the second phase, new investments makes the prices level out, but the market exhibit long-term fluctuations due to the long time delays in capacity acquisition. We should also note the declining price trend that becomes apparent towards the end of the simulation period. Technology progress drive down the cost of renewables. In this scenario, renewables also enjoy a subsidy of 100 NOK/MWh throughout the simulation period, which is taken into account during the profitability assessment. To compare long-run marginal costs of the various technologies, see *Figure 14.3*. In *Figure 14.3*, long run marginal costs shows a declining trend for most of the technologies, but resources constraints can potentially increase costs, which is the case with biomass, and will be the case with onshore wind, if more resources are utilised.

Figure 14.3 Long run marginal costs
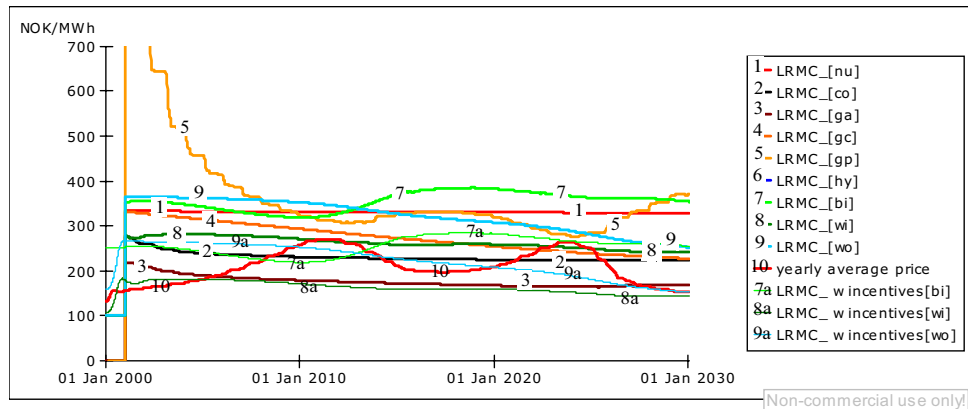
Figure 14.4a shows a close-up of the first five years of electricity generation, in order to show the seasonal variation and the generation scheduling. The regularity of hydropower makes it well suited for peak load. Nuclear remains base load, followed by coal, which reduces its capacity utilisation during the summer season. As more coal is phased out, the more efficient and modern plants remain, and a higher capacity utilisation can be observed for remaining plants, but this effect is also due to the price increase. Only the seasonal- and weekly demand pattern is included in this simulation.

Simulating with an hourly resolution enable us to capture diurnal load pattern, in which case the start/stop constraints of thermal plants must be represented. These effects could be important for the results of CO_2-emissions, and are left for future work.

Figure 14.4b shows the entire simulation from *a)*. Here, we can notice the trend in development of generation, as well as the generation scheduling that is endogenous in the model as described in *Chapter 8*. *Figure 14.4c* shows the average yearly generation for the same simulation as in *a)* and *b)*.

Figure 14.4 Electricity generation : a) close-up of first 5 years showing seasonal variation, b) seasonal variation over 30 years, and c) average yearly generation of the same simulation run.

a) Close-up - simulations from 2000 - 2005, generation.   Seasonal variation in demand, inflow and demand present. Nuclear serve as base load, followed by coal.
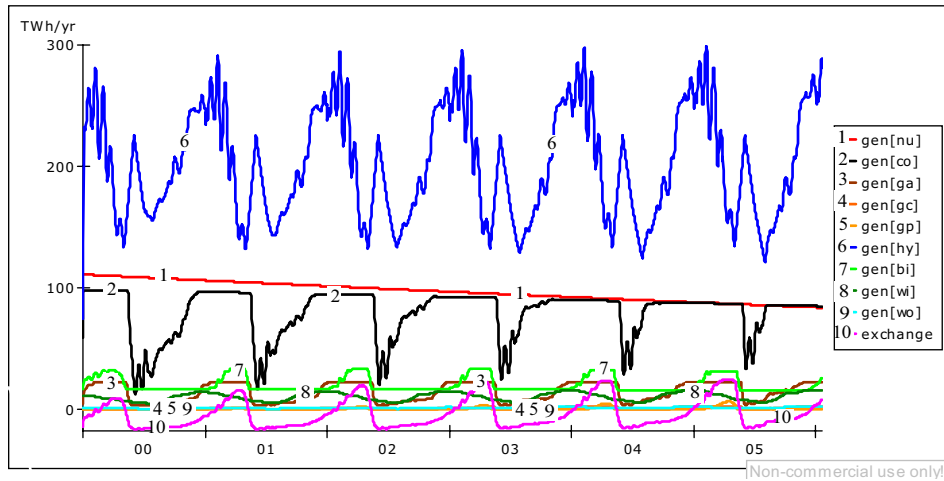
b) Graph displaying the whole simulation run; 2000 - 2030 of generation
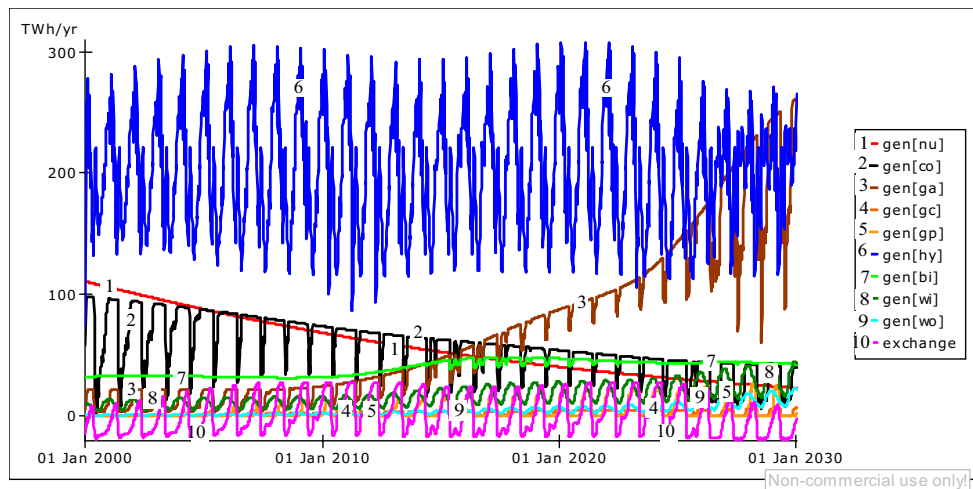
Figure 14.4 Electricity generation : a) close-up of first 5 years showing seasonal variation, b) seasonal variation over 30 years, and c) average yearly generation of the same simulation run.

c) The same simulation run, but yearly averages to display trend.

Figure 14.5 shows construction completion rate. Investment patterns become more ap-
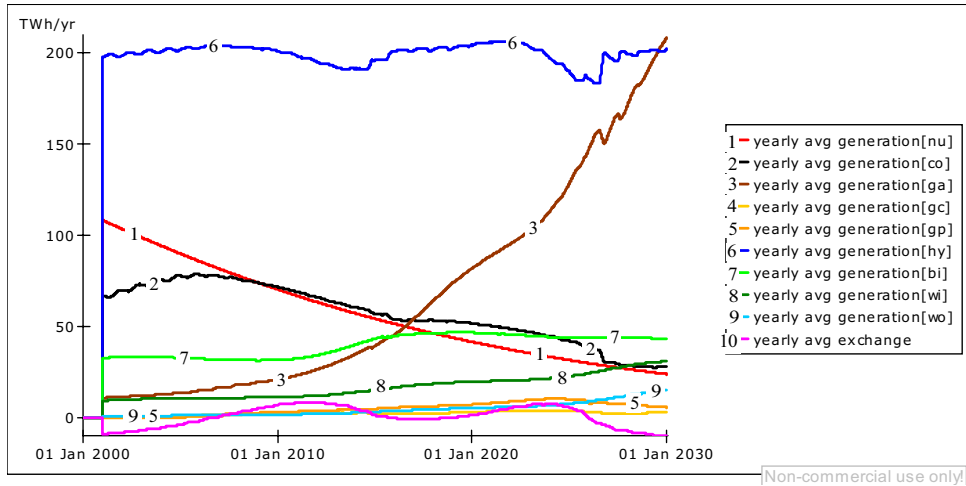
Figure 14.5 Construction completion rate of new capacity.
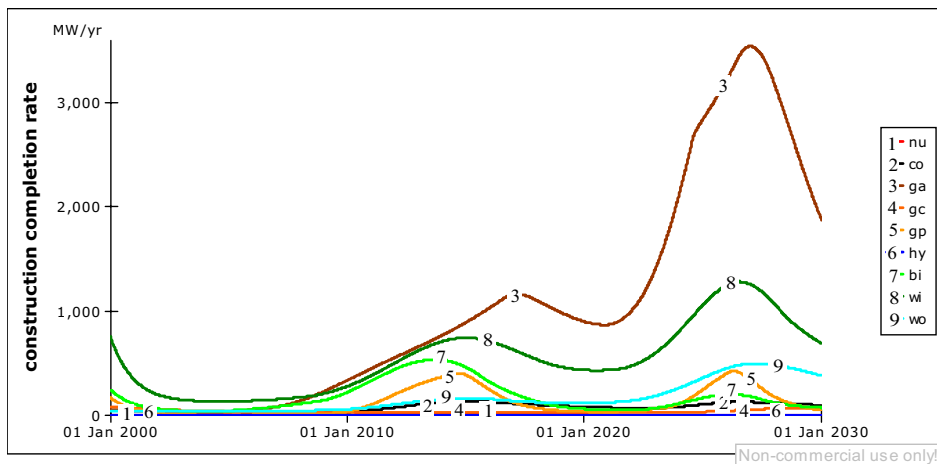
parent here than in the corresponding *Figure 14.1*.

Figure 14.6 shows a net increase in CO2-emssions in the long run. During the first phase of overcapacity, the utilisation of coal plants increase, with a corresponding increase in CO2-emissions from coal plants. Emissions from coal are then gradually reduced along with the phase-out of existing plants. Gas power on the other hand increase its contribution to CO2-emissions. We can also notice a situation of net export that gives an initial reduction of CO2-emissions outside the Nord Pool area. We make a conservative assumption of substi-

tuting the least efficient coal power units in Germany when exporting. After the price increase in Nord Pool, however, we reach a situation of net imports, which contributes positively to our CO2 emissions.

Figure 14.6 CO2-emissions

a) Yearly average CO2-emissions
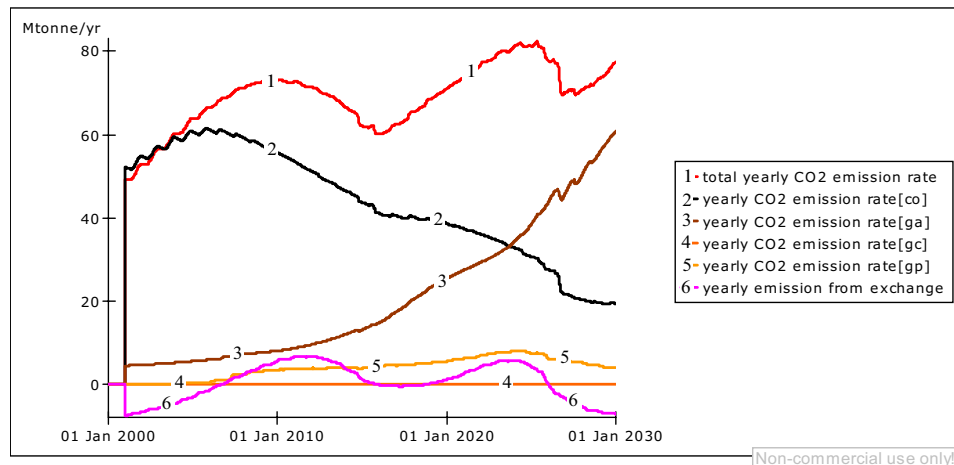
b) CO2-emssions with seasonal variation
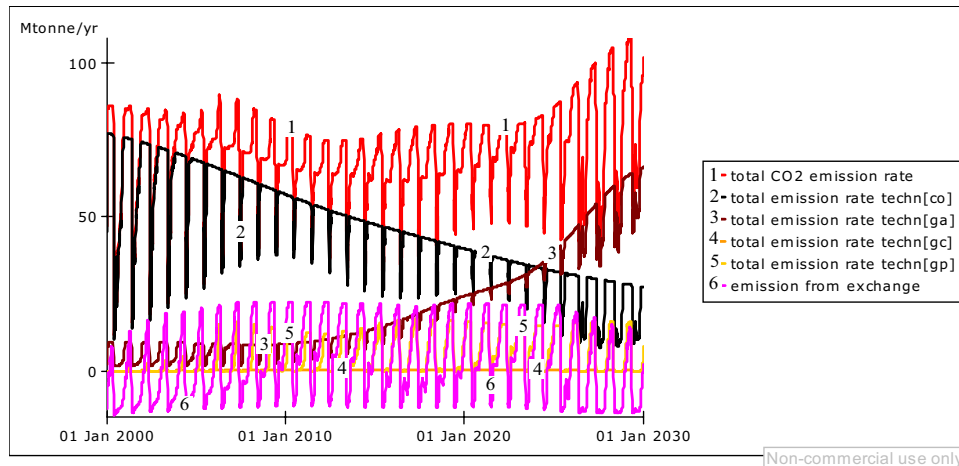
In this simulation run, CO2-emissions increase. Emissions from coal are however declining, while the large amount of gas power contributes to an increase. At some point, there is a decrease in CO2-emissions, where the fluctuations has to do with the long-term price fluctuations, which alters the capacity utilisation of thermal generation. Emissions induced by exchange are also accounted for. When there is a net export, CO2-emissions corresponding to the least efficient coal plants are reduced in Europe. This is a rather conservative assump-

tion, and it is more likely that exchange with Germany substitute gas power in Germany rather than coal power.

Figure 14.7 shows the demand development. The seasonal pattern shows demand and

Figure 14.7 Demand and net generation
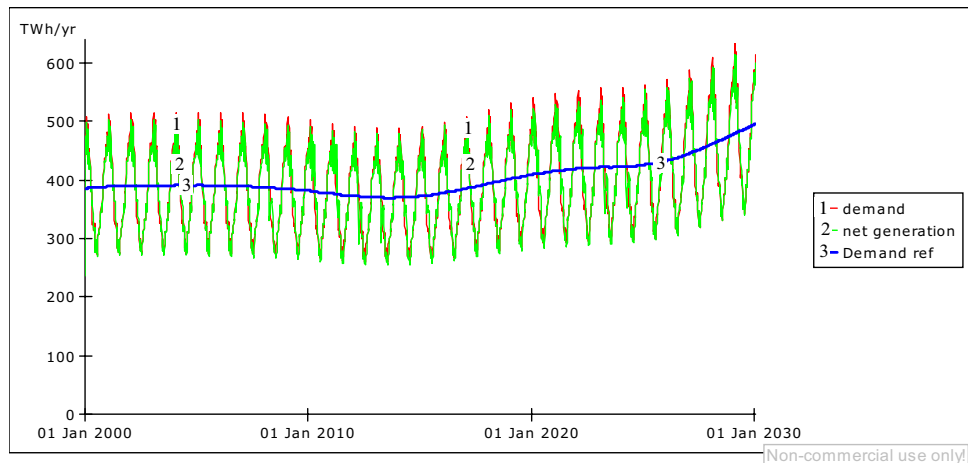
net generation, while the straight line shows the yearly average demand. A high price elasticity of demand staggers growth somewhat in the first part of the simulation. As a check, demand and net generation matches closely. The time resolution and the price adjustment time can be set small enough to ensure a sufficiently close match between demand and net generation.

Figure 14.7b shows reservoir filling over 30 years. The average reservoir level adjusts in correspondence to the price level. There is some inertia in the process of updating the water values, which is the basis for reservoir management as discussed in *Chapter 8.4*. If new capacity additions have made price levels drop, the reservoir level may be larger than optimal until the new capacity additions are included in the models that are used for long term hydro scheduling. If we compare *Figure 14.7b* against *Figure 14.5*, we can observe that average reservoir levels are low in the years with peaking prices, and correspondingly high in the

years with low prices. Reservoirs adds even more long-term dynamics to the power system in exchange for damped price peaks.

Figure 14.8 Reservoir level development

a) Reservoir level development over 30 years
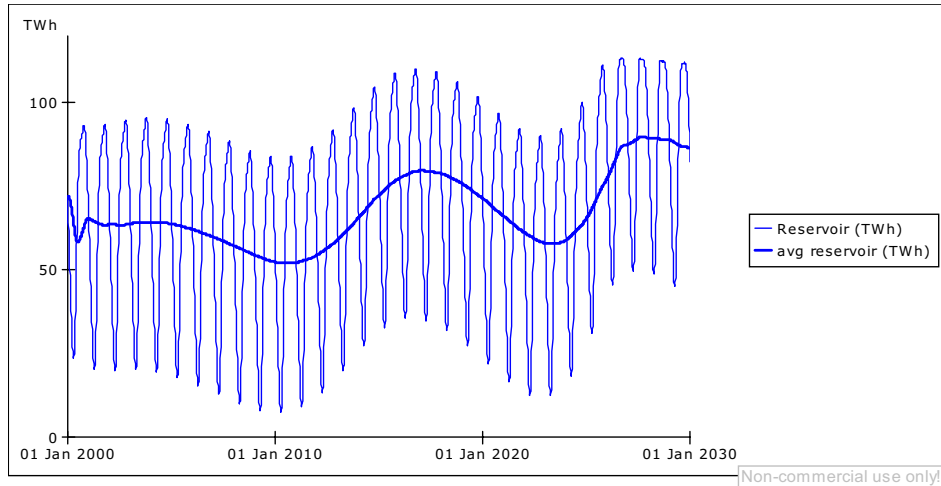
b) Close-up of reservoir curves for the first few years.
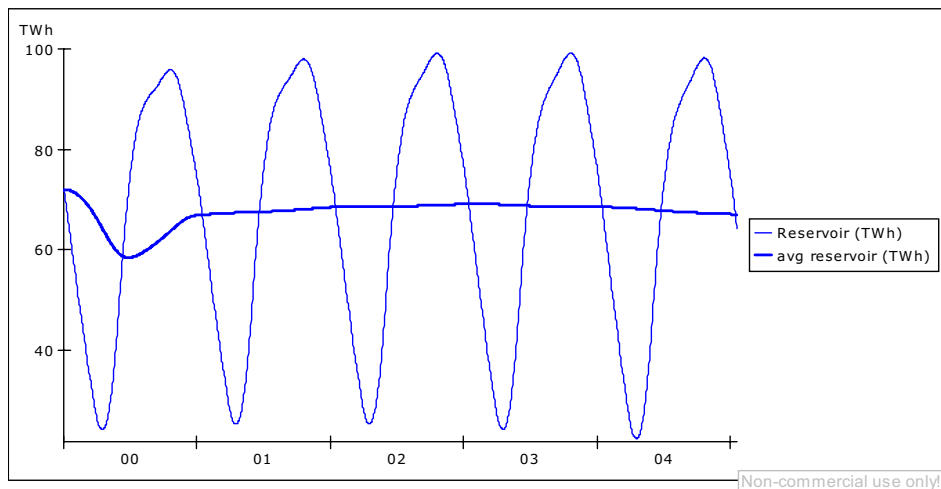
14.2 CO2-taxes

In this scenario, we impose a CO2-tax of 80 NOK/tonne CO2 in 2005. This tax level corresponds to recent CO2 quota price levels in the current marketplace[1]. Of course, sudden changes like this do not correspond to reality, as such changes are well announced in advance.

1. See www.pointcarbon.com

However, such a step change allows us to inspect the system response and identify major cause-effect relationships that are brought into play. The thin lines now correspond to the reference run for comparison, and bold lines correspond to the simulation run with CO2 taxes.

First, coal generation drops in response to the imposed CO2-tax. Hydropower, imports and to a less extent gas power compensate for the reduced generation from coal. However, hydropower generation can only increase its production over one to two years, draining the average reservoir level. This behaviour reflects the adjustment in the perception of what is the new average price level for which water reservoirs must be adjusted, and will probably adjust faster in practice, as utilities and consultant companies implement CO2-taxes in their decision support models.

Figure 14.9 80 NOK/tonne CO2-tax imposed in 2005
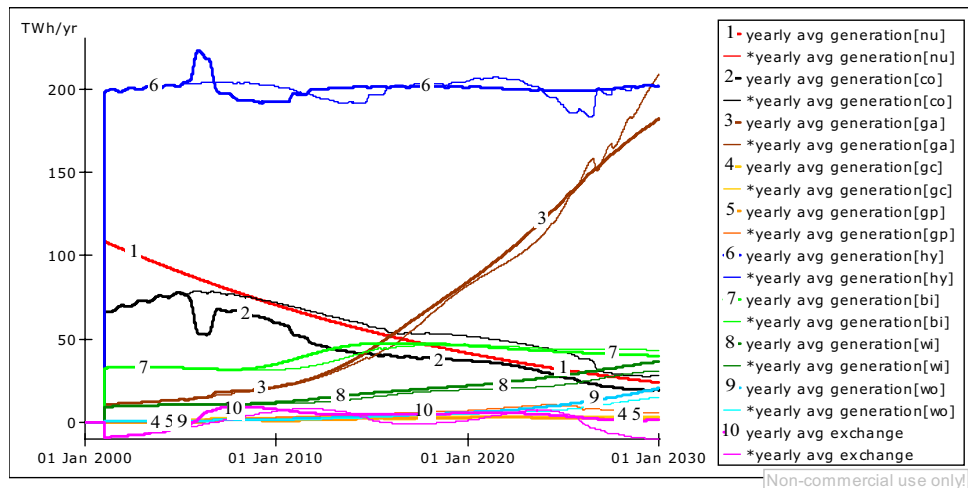
Figure 14.10 Price response to CO2-tax in 2005.
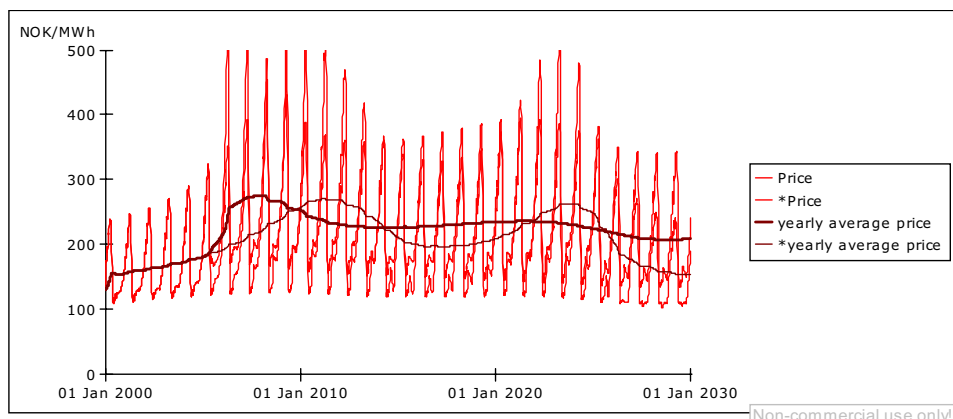
The price jumps immediately, and levels a bit higher than in the reference run. Somewhat surprisingly, the tax "shock" seems to stabilise prices, as we seem to avoid the long-term price fluctuations that appeared in the reference run. There is a natural explanation for this. The coal capacity made unprofitable is now idle, and will be utilised if prices gradually increase.

Figure 14.11 shows the capacity development in response to the CO_2-tax. The level of gas power is reduced, while renewables increase comparatively.

Figure 14.12 shows the resulting CO_2-emissions that corresponds directly to the development in generation from coal, exchange and gas. CO_2-emissions are reduced compared with the reference run, but the emission rate will continue to increase in the long run from present situation.

Figure 14.11 Capacity development with the introduction of CO_2-tax in 2005. Thin lines: reference run, bold lines: CO_2-taxes imposed
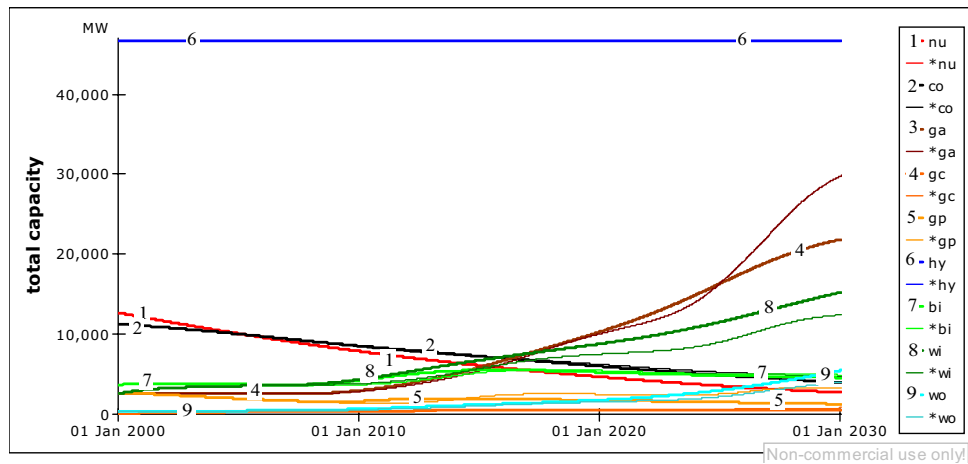
Figure 14.12CO2-emissions. Thin lines: reference run, bold lines show simulation with CO2-tax imposed
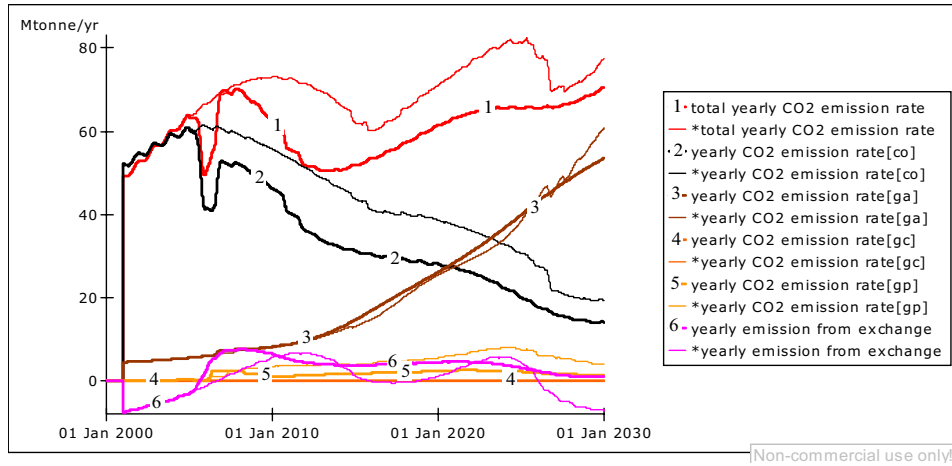
These simulation runs illustrate the complex dynamic of the Nordic electricity market, and how energy policies can be tested. The next part of this thesis will apply the model to two particular policy studies of the Nordic electricity market.

Part III

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

Felix qui potuit rerum cognoscere causas
"Happy is he who comes to know the causes of things"

- Virgil-Georgics Book II line 490 29 BCE

15 Long term versus short term substitution effects of gas in a liberalised electricity market

15.1   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 NORDMOD-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.

15.2   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.

15.3   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 15.1*. Scenarios for 2010 are based on several reports (in addition to the above mentioned) according to energy policy goals of each Nordic country.

	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

Table 15.1 Generation mix in the Nordic countries 1999. The column for 2010 is the future electricity mix according to political targets.

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 15.1* 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

Figure 15.1 Historical development of consumption, reservoir level and spot price for the Nord Pool market 1996-2004. (Source: Nord Pool)
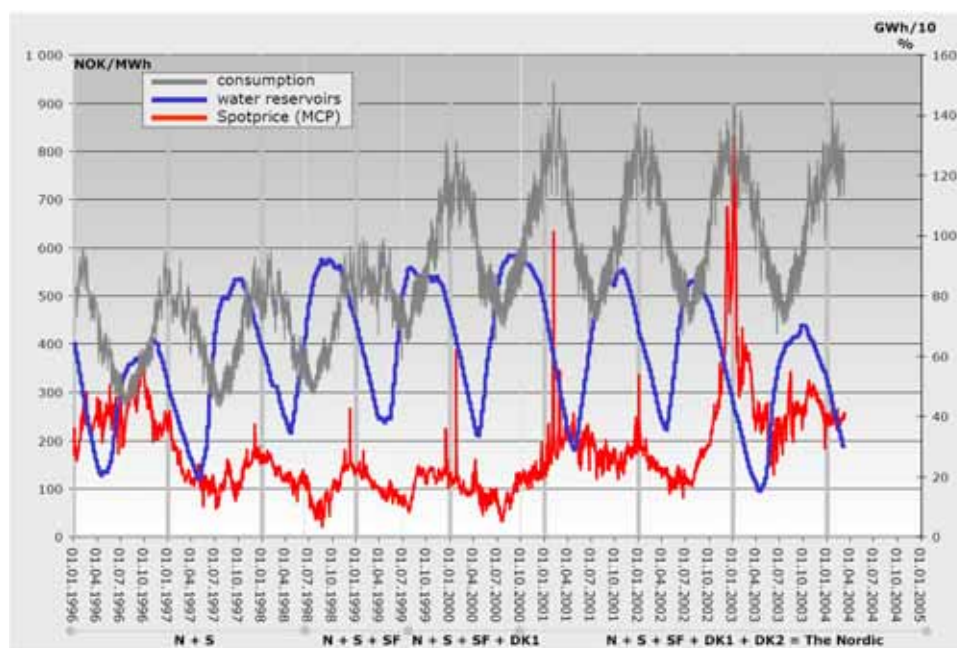
from year to year.

15.4   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 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 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.

15.5   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

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1. CNN news, 09.03.2000

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]

15.6   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 analyses.

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.

15.7   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 15.2* shows the supply curve of the Nordic electricity market that has been used in our EMPS simulation runs and

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1. Interview with T. Bye (Statistics Norway) in Dagbladet, 31.10.2000
2. National Pollution Authority
3. Interview with Domingo Jimenez-Beltran, (EU Minister of Environment) in Dagbladet 25.10.2000

earlier versions of the Kraftsim model (Vogstad et al., 2002). Hydropower, wind power and

Figure 15.2 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)
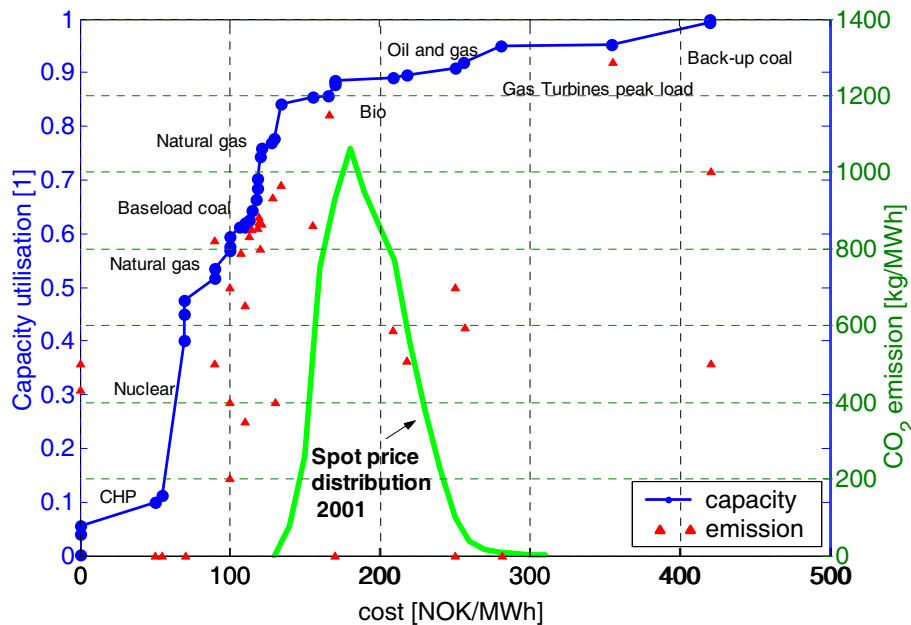
exchange are not included in the supply curve. Nord Pool's spot price distribution for 2001 is shown in the same graph. Held together with the supply curve, the data shows a picture that does not quite match the assumptions of coal being the only generation technology replaced by gas. From the supply 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) 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 for utilities and regulators. *Table 15.2*

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 15.2 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

15.8 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 15.2*. 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 15.3 shows an overview of the physical description of supply and demand within each

Figure 15.3 The EMPS model consists of several interconnected local areas with various supply technologies, demand and market access. (Source: Vogstad et al, 2001; Vogstad 2000)
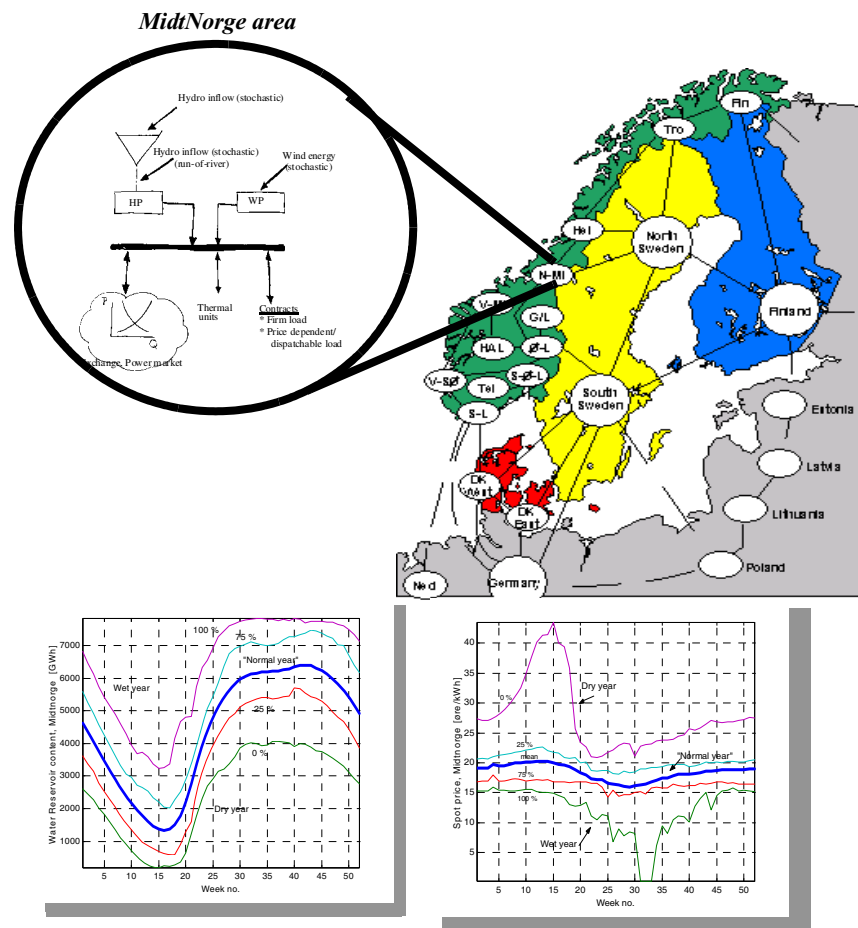
area. The graphs show the optimal reservoir level curves, and the resulting prices. The results are shown as percentiles emphasizing the stochastic optimisation of hydro scheduling with stochastic inflow.

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 building 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*

Figure 15.4 CLD representation of the EMPS model
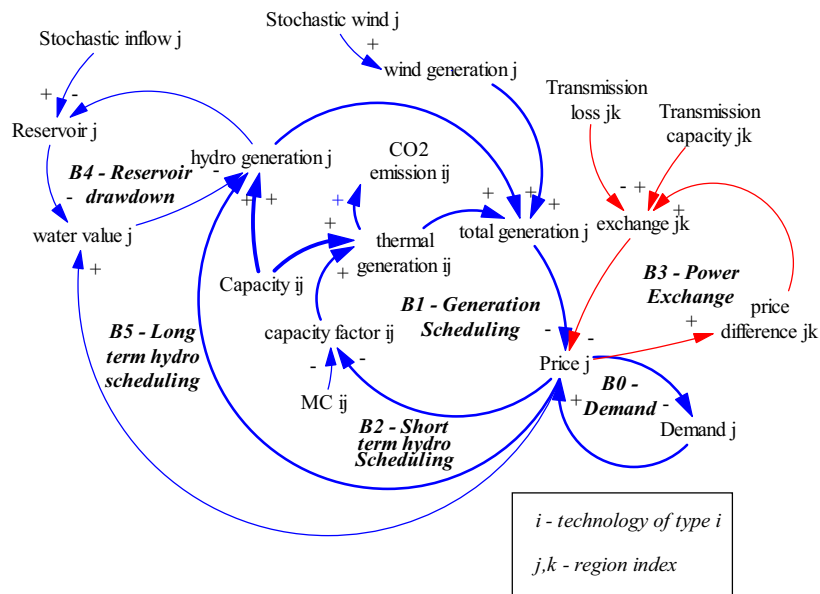
15.4 shows a CLD representation of the EMPS model. As can be seen, Capacity is exogenous to the model. Consequently, investment substitutions must be handled exogenously. The power exchange loop (B3) represent exchange between areas. The exchange depends on the available transmission capacity between 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 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 15.3 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

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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.

to the total emission values, which suggest the analysis to be highly sensitive to assumptions made.

Table 15.3 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 15.4 EMPS 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 15.4*, 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 15.2* 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 B)

ref2010 - Scenario 2010 without new wind power, as defined in *Table 15.1*

wind2010 - With 16 TWh/yr wind power according to each country's plans. (see *Table 15.1*)

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 pos-

sibility 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.

15.9 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 15.5* shows the *generation scheduling*, *power exchange, capacity acquisition* and *resource availability* feedback loops. Investments in a technology are made if long-run mar-

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

ginal costs are lower than the market price for the *next time period.* Capacity is then added

Figure 15.5 CLD representation of NordMod-T
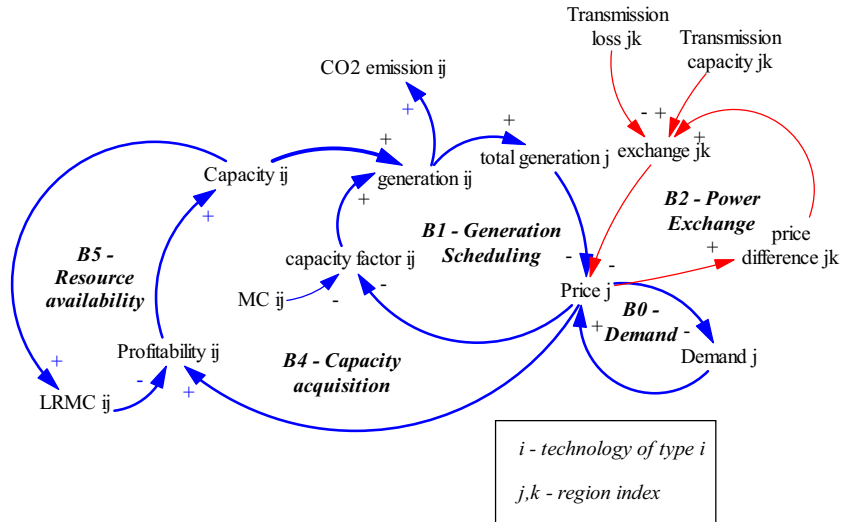
the next period (investments are made at the start of each year). There is also a maximum constraint on the amount of capacity from each technology that can be added.

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 below:

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*

Figure 15.6 Left: Assumptions on tranmission capacity to non-nordic countries. Right: Price scenarious for non-Nordic countries, base run. (Source : Aune et al. 2000)
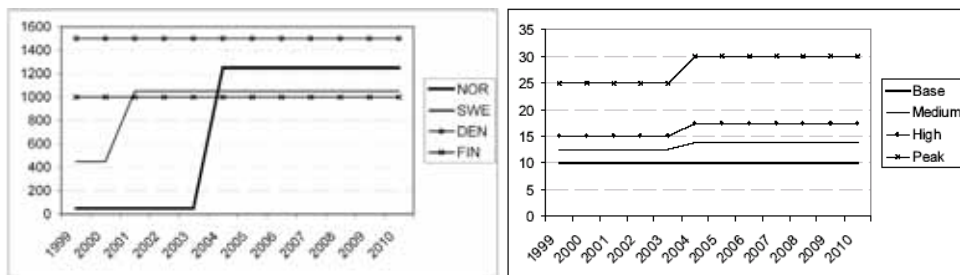
15.6 for the NordMod-T simulations. *Figure 15.7* shows the development of CO_2 - emission

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 15.7 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)
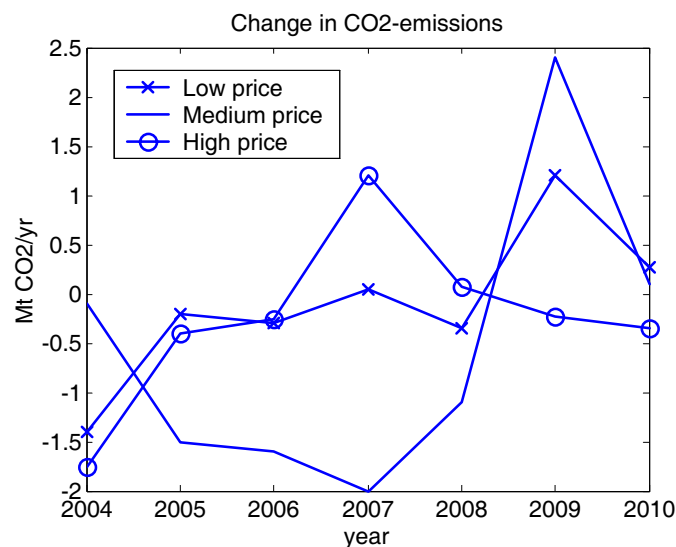
The study concluded that there is high uncertainty whether building gas power in Norway increase or reduce Northern European CO_2-emissions, and that the results rely heavily on the assumptions made, in particular the price level in Europe, and the available transmission capacity to Europe. If transmission 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.

15.10 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 on the competition between the following main technologies nuclear, coal gas gas with CO2-sequestration, peak load turbines, hydr, bio, wind and wind offshore.

The main loops of Kraftsim is shown in *Figure 15.8*

Figure 15.8 Kraftsim CLD diagram
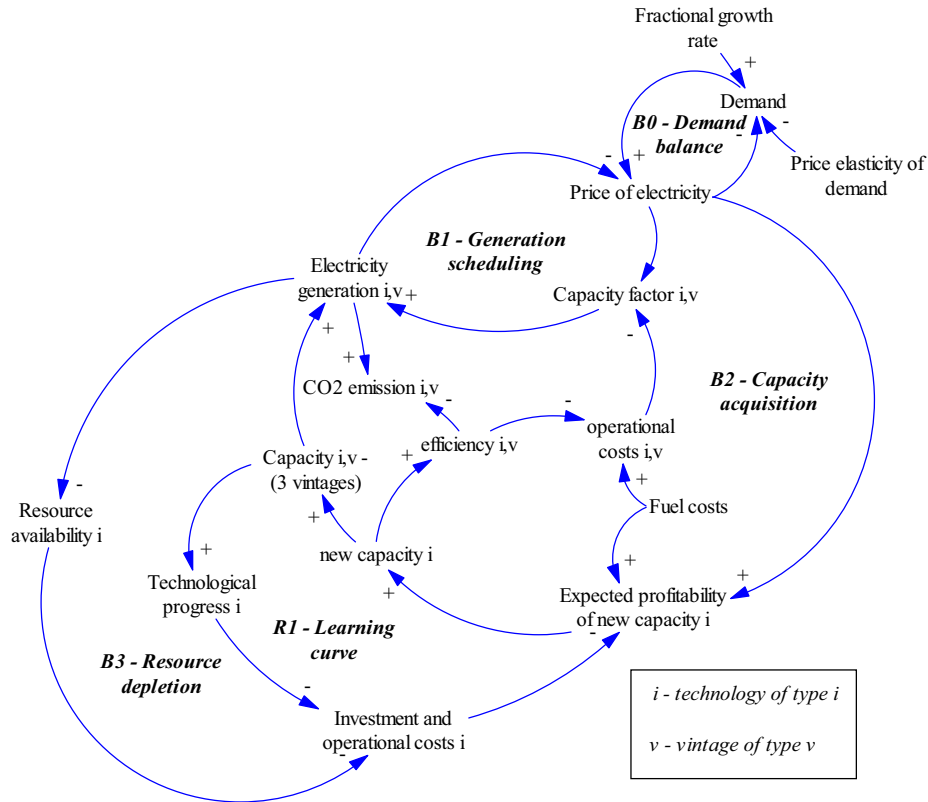
B1 - Generation scheduling. On a daily basis, electricity generation is scheduled by marginal costs of operation. The last unit in operation determine the spot price at each time point (in a uniform-price auction, perfect market). In this model, the supply is described by each of the nine technologies *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.

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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 *generation scheduling* problem)

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 15.2).*

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15.11 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 15.9 Spot price development for the reference case (*) and the fuel substitution scenario introducing 3200 MW natural gas in 2005.
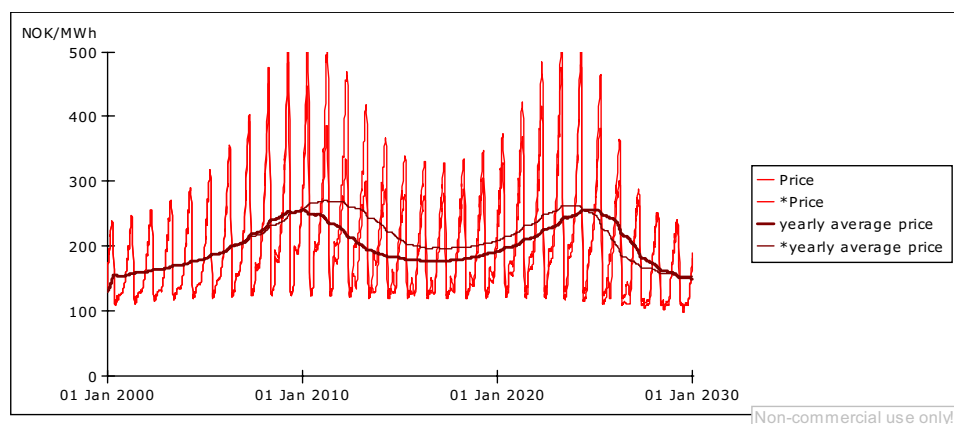
15.11.1 Electricity price development

The observed development in the reference run deserves some explanation. In *Figure 15.9* 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.

Figure 15.10Future prices versus long run marginal costs of generation technologies
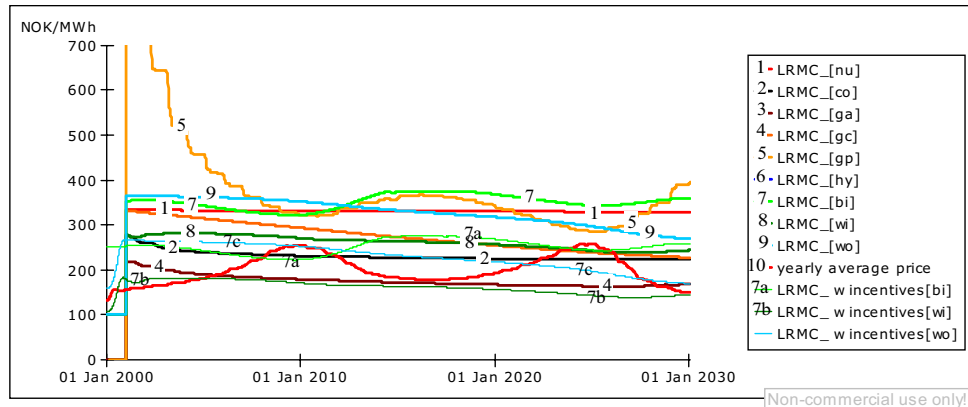
The increasing price trend towards 2015 is due to the initial overcapacity in the Nordic market. The capacity acquisition loop drives the market towards long-run equilibrium, so that the long-run electricity market prices approach the long-run marginal costs of new generation. If we compare the *futures price* with the long-run marginal costs (LRMC) of new generation in *Figure 15.10*, 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 section 9.2) - 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 15.9*. Obviously, the introduction of new gas power suppresses electricity 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).

15.11.2 Substitution effects in capacity and generation

Figure 15.11 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*.

Figure 15.11 Capacity development. The investment substitution effect of adding gas power
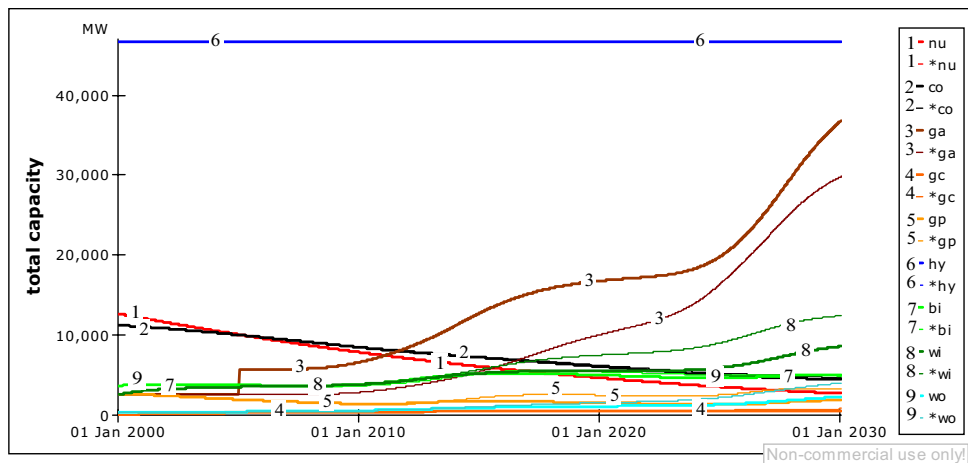
If we now consider generation scheduling, *Figure 15.12* shows the (averaged) yearly generation for each technology. As can be seen, coal (2) responds slightly by reducing its capacity utilisation when 3200 MW natural gas is added in 2005. The marginal costs of coal are, however well below the new market price trajectory, and the substitution effect 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.

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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.

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

The reduced generation corresponding to reduced investments can be observed for bio, wind and offshore wind (see bold line) in *Figure 15.12*.

Figure 15.12Yearly generation. Short run substitution effects in generation of adding gas power.
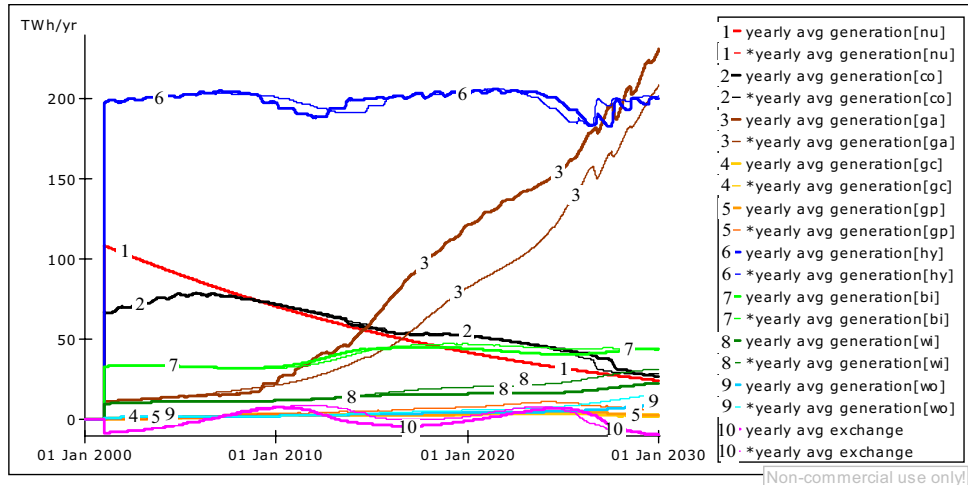
A more detailed inspection of gas generation and coal generation after 2005 (*Figure 15.13*

Figure 15.13Development of gas power generation.   Thin line shows reference run, bold line shows the scenario with 3200 MW new gas power added in 2005.
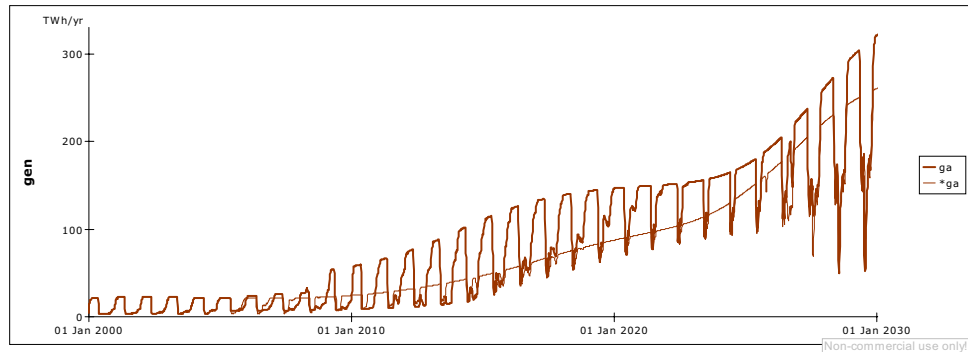
and *Figure 15.14*) shows that the capacity capacity utilisation will be lowered in comparision ot the reference run for gas power. When it comes to coal, the substitution effect of coal is rather modest, as operational costs of coal are lower than the new price level.

Figure 15.14Coal generation. Thin line shows reference run, bold line shows scenario with 3200 MW gas power added in 2005.
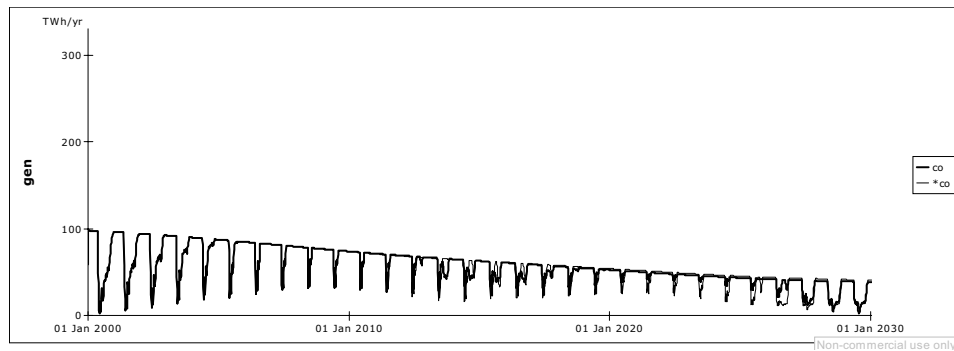
15.11.3 Long run versus short run effect of the fuel substitution strategy on CO_2-emissions

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 ar-gued 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 technology. This conservative assumption provide an upper bound scenario for emissions accompanied by im-ports, 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 15.15Change in CO$_2$-emissions from building gas power compared to reference run (*)
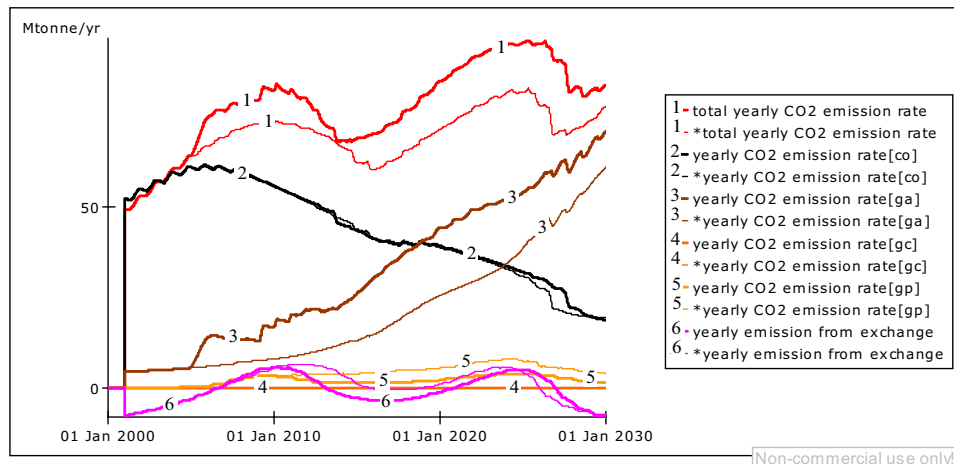
15.12 Structural- and parameter sensitivity of the simulation results

15.12.1 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.

15.12.2 Representing transmission constraints

One of the main differences between the three models, are the 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 market 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.

15.12.3 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 quickly 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 generation scheduling 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 generation scheduling 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.

15.13 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.

15.14 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.

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Notes

1. Seasonal price variations (*Chapter 15.11.1*)

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 15.11.1)

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 section 9.2). 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 15.10*).

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.

16 Tradable green certificates: The dynamics of coupled electricity markets

16.1 Abstract

Liberalisation of markets previously under regulatory control require new instruments for environmental policy making because subsidies and regulatory intervention does not conform to trans-national liberalised markets. This is the case for newly regulated electricity markets. An arrangement of Tradable Green Certificates (TGC) as a market-based subsidy for renewable energy has been proposed in several countries and already implemented in a few. However introduction of TGCs have been postponed and delayed mainly due to the uncertainties involved for suppliers of renewables. Several studies have been undertaken using economic static comparative analysis and partial equilibrium models. However few of these analyses address the dynamic price formation process or the mechanisms that are important in the design of a well-working stable market. To analyse the stability of a TGC market we construct a system dynamic model of the TGC market coupled with the Nordic electricity market (Nord Pool). A set of trading strategies for the participants under various marked designs is examined. These trading strategies were deduced from laboratory experiments.

The results showed that the proposed TGC market designs are likely to become unstable. These instabilities arose endogenously from the trading strategies. Some crucial design parameters such as banking and borrowing can reduce these instabilities. In particular the proposed banking arrangement intended to avoid price fluctuations caused by the yearly stochastic variation of renewables. As a side effect banking opts for some trading strategies that cause even more harmful price fluctuations followed by price crashes.

These undesirable instabilities can be reduced by allowing borrowing and limit banking. The conclusions from previous theoretical studies on the TGC market is examined and compared with our findings. This case study shows how system dynamics can be combined with experimental economics to address issues that cannot be dealt with within the framework of partial equilibrium models and standard economic theory.

16.2 Introduction

Liberalisation of European markets requires new tools and instruments for environmental policy making. Utilities and public services (i.e. electricity waste management telecommunications) previously under regulatory control are now subject to deregulation. Under these conditions traditional national environmental policy instruments do not necessarily work as intended (Morthorst 2000). As an example the main goal of developing wind power in Denmark was to reduce national CO_2-emissions but under the operations of the liberalised Nordic electricity market these CO_2-reductions take place in Finland and Germany rather than Denmark (Vogstad et al 2000). National subsidy schemes also distort competition in transnational markets. This points to the need of environmental policy instruments that are compatible with open markets.

Tradable green certificates (TGC) have been proposed in Denmark Sweden and within EU to achieve their goal of adding 340 TWh renewables within 2010. However introduction of TGCs to replace the renewable subsidy scheme has been delayed several times in Den-

mark. A mandatory TGC market will start from May 1st 2003 in Sweden. A TGC market has been in operation in the Netherlands since 2001 but differs from the proposed arrangements of the Nordic countries and EU by not being mandatory on the demand side.

Langniss and Wiser (2003) discusses the experiences of renewable energy portfolio standards[1] (RPS) where the Texas RPS has given promising results in developing renewables. In the case of Texas however wind power received favourable subsidies in addition to the TGC's so that the system has not really been put to test yet.

Favourable feed-in schemes for wind power in Denmark Germany and Spain have indeed been successful in developing the industry from being an alternative energy source to becoming a competitive energy technology. One disadvantage about this feed-in scheme is the large amount of costs it inflicts on the authorities as the renewable generation grows. As a result direct obligations on the consumers were proposed coordinated by a TGC market.

16.3   The principle of tradable green certificates

The main purpose of tradable green certificates is to *increase the share of renewable generation* at minimum costs.

TGC's are financial assets issued to producers of certified green electricity and can be regarded as a market-based environmental subsidy. An issuing Body (IB) issues green certificates at the moment a producer registers the production of actual green electricity. They are later withdrawn from circulation at when customers account for their obligations by presenting the certificates to the registration authority or if the certificates period of validity expire. Between issuing and withdrawing the certificates are accounted and can be traded. The cer-

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1. Renewable Portfolio Standards is another term for Tradable green certificates

tificates function as an accounting system to measure the amount of electricity produced from renewable energy sources.

Figure 16.1 The principle of a TGC market. TGC's are financial assets that can be traded independent of electricity generation. The value of a certificate reflects the cost of providing the additional amount of new renewables needed to fulfil the obligation.
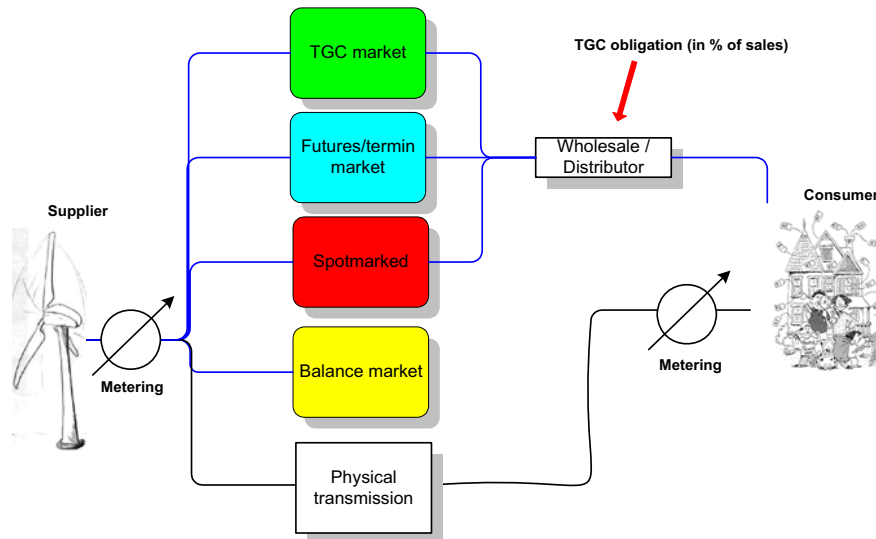
Figure 16.1 shows in principle how a TGC market will work within the Scandinavian electricity market (Nord Pool). In the Nord Pool market electricity and its derivatives are traded in double-auction markets. The spot market is used for hourly *production scheduling*. The Balance market coordinates *short-term regulation*[1]. Futures contracts are used for electricity trading up to 3 years ahead and are hence used for *long-term* planning and *investment planning*. A TGC market values the environmental benefit of renewables as a service. The authorities define a mandatory share of demand for renewable generation and the TGC market then finds the price needed to reach this target.

It should be noted that all these markets work independently of the physical transmission and that all necessary metering for accounting is made at the supplier and consumer.

16.4   Implications of TGC markets

One of the main lessons from standard economic theory is that instrument must be directed directly towards its purpose in order to be efficient. Hence a TGC system will typically be a cost-efficient way to increase the *share of renewable electricity* in consumption because the market will find the price needed to reach the predefined target and the cost of renewables are directly paid by the consumers. Similarly a TGC system is not an efficient instrument of reducing CO_2-emission. Efficient CO_2-reduction can be obtained by a CO_2-quota market. However, both reducing CO_2-emissions and increasing the share of renewables are present

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1. The balance market provide capacity for available for regulation within a period of 15 minutes.

environmental policies, which justifies the use of both in environmental policy making. Jensen & Skytte (2003) provides an analysis on the simultaneous attainment of CO2 and renewables targets.

Subsidy schemes require authorities both to set renewable targets and to find the sufficient level of subsidies that will ensure targets to be met. In a TGC market system the authorities can focus on the renewable target leaving the price setting to the market.

A large market is preferred to obtain the real benefits of a TGC market. Firstly resources are unevenly distributed across countries. The EU-project Renewable Burden sharing (Re-BUS) identified a total 15% cost reduction potential of achieving the EU targets of additional 340 TWh new renewables within 2010. Some of the countries could however reduce their costs by 40%.

Secondly, a larger number of participants will reduce the possibilities for market power. However opinions differ among EU countries with respect to which type of technologies that can be defined in the TGC portfolio. Large-scale hydropower and waste incineration remains an issue as to whether these sources should be included in the TGC market. Allowing large-scale hydropower is in conflict with the intention of TGC's. Hydropower undoubtedly renewable *is* a competitive source of generation and most of its potential has already been utilised. The technology is mature and projects that do not conflict with environmental interests are limited. Allowing hydropower in a TGC system would do little more than generate additional income to hydropower utilities until TGC prices drop to zero.

Waste incineration can in some cases be considered as renewable in some cases not - for instance when plastic is incinerated. In many cases waste incineration is profitable due to high deposition costs. Such controversies must be sorted out to take advantage of the possible benefits of a TGC market.

A real disadvantage of TGC markets is that the less competitive sources such as PV and wave energy will not be able to compete against cheaper alternatives of wind energy and bio. Such technologies will still be in need of subsidies.

16.5   A system dynamics analysis of the TGC market

The implications of a TGC market have been the subject of studies in several reports mainly in the form of comparative static analysis or using partial equilibrium models e.g. the

Figure 16.2 Model hierarchy. In this approach we model develop submodels of the electricity spot market the TGC market and TGC Trading strategies before the models are fully interconnected.
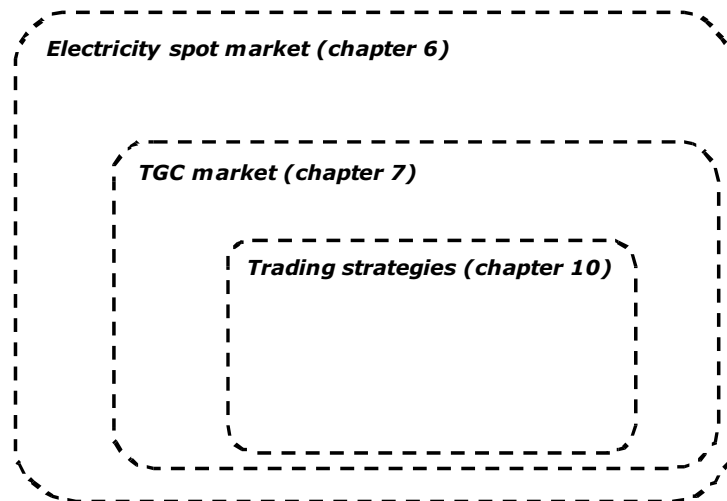
Swedish white paper on TGC's (SOU 77:2001) the EU-project REBUS and a series of studies at Risø and under the Nordic research project Nordleden[1] (Risø 2002). To our knowledge TGC markets have been simulated in the Markal energy model plus Econs power market model and the Balmorel energy model (Hindsberger 2003). These models are all partial equilibrium models and can be used to simulate the development of different sources of renewables the TGC price and their substitutes. They do not however address the consequence of time lags involved in construction of new capacity or possibilities for strategic behaviour of purchase and sales of TGC's. To which extent these characteristics are important for the price and for the design of a TGC market is the subject of this study.

Figure 16.2 shows our stepwise approach of constructing a system dynamics model of the electricity spot market including a TGC arrangement. The purpose is twofold. First to study the price formation in the TGC market under various designs. Second to analyse its interactions with the electricity market.

In section 16.6 we develop a simplified model of the Nordic electricity market where renewable generation is traded in the spot market with the present feed-in scheme for subsidising renewables.

In section 16.12 we develop the TGC market that replaces the feed-in scheme from 2003 on. There are uncertainties and different opinions concerning stability of the proposed TGC market designs (Schaeffer & Sonnemans 2003; STEM 2002; Krohn 2001).

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1. For reports on from the Nordleden project on TGC's see http://www.nordleden.nu

In section 16.16 we elaborate the TGC market model further by representing trading strategies of buyers and sellers enabling us to address the issue of price stability under various market designs. Using the system dynamics approach we explore some common trading strategies to study the impact on price dynamics under the proposed TGC designs. The trading strategies were deduced from a laboratory experiment with a group of players. Based on these simulations and experiments we identify some crucial design parameters for a well-working TGC market. Finally we connect the TGC market model with the Electricity spot market model to study the interaction of those.

16.6   The spot market for electricity

We start our analysis by establishing a stock & flow model of the supply and demand side of the Nordic Power Exchange (Nord Pool). The time horizon was set to 20 years as renewable targets are part of long-term energy and environmental planning. Capacity utilisation is in turn determined by the spot prices and a numerical time resolution of 3 days is sufficient to adjust spot prices according to the changes in demand and supply[1]. We start with a de-

Figure 16.3 Spot market dynamics CLD.
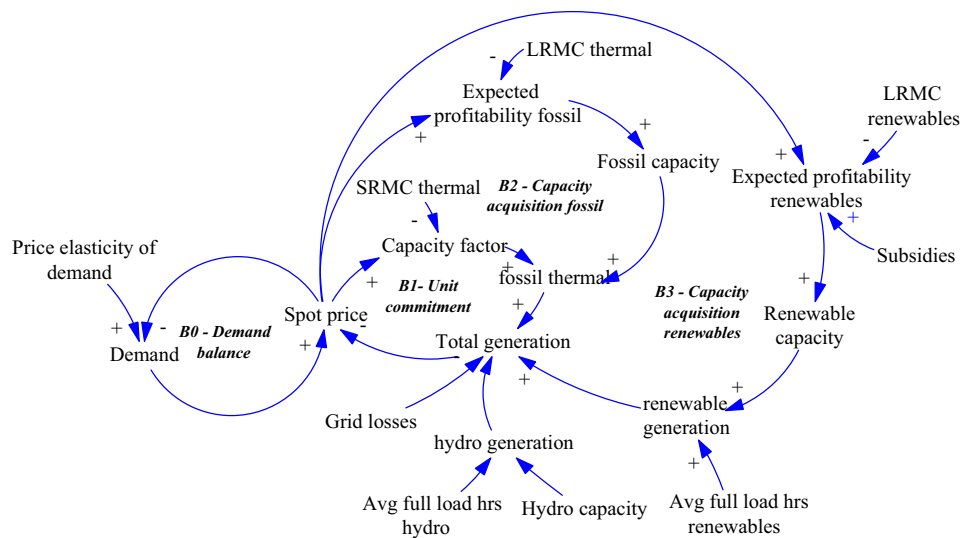
scription of the power market with a feed-in tariff subsidy scheme for renewables to be used as a reference for simulations with a TGCs market. *Figure 16.3* shows the causal loop diagram (CLD) of the spot market. For simplicity we only distinguish between thermal generation hydropower and renewables. Hydropower is indeed renewable but for the purpose of

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1. To represent market spot prices as a goal-seeking process require small time constants in comparison to the other time delays in the system i.e. time delays for capacity acquisition and lifetime of installed capacity. An alternative way is to find market equilibrium prices using a search algorithm within each time step.

certificates existing large-scale hydro is not included for reasons mentioned in section 16.4. On the supply side two balancing loops are involved in the price formation. The loop *B1* adjusts generation of electricity by the short-run marginal cost curve of existing capacity (see *Figure 16.6* for details on the supply curve of thermal generation). If spot prices sustain at a higher level than the long-run marginal costs of generation (LRMC) new capacity will be added. The capacity acquisition loop *B2* and *B3* is similar for both thermal and renewable generation except that subsidies and tax policies affect their profitability. We assume hydropower capacity to be fixed in this simplified model.

16.7 Market dynamics

Figure 16.4 Spot market dynamics stock & flow diagram

a)
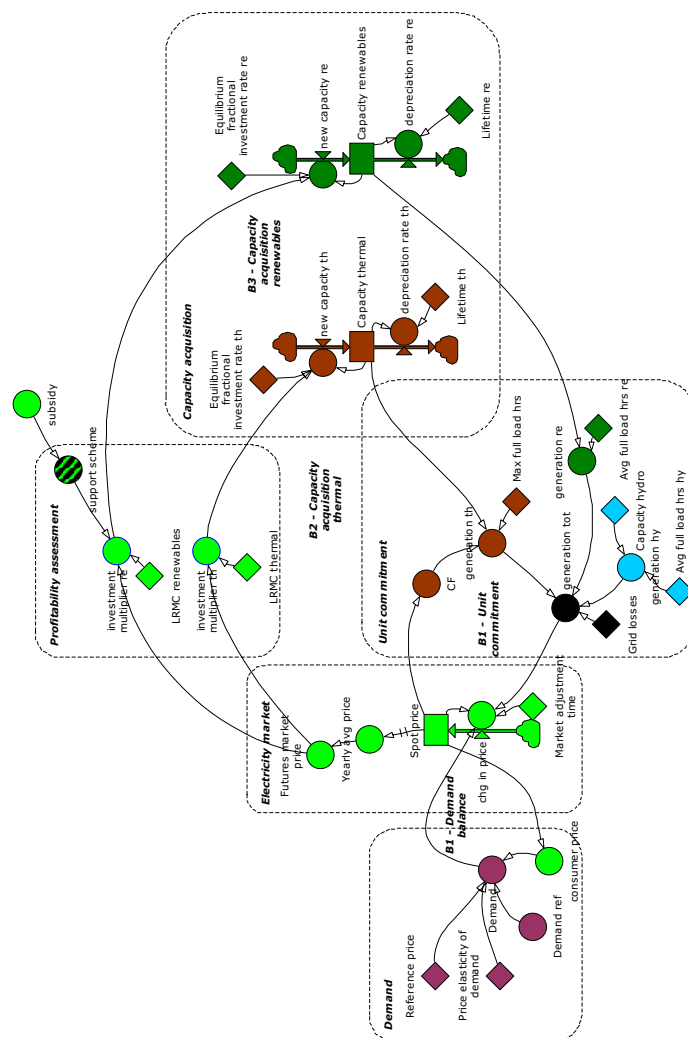
The Nord Pool electricity market is a double-auction market that clears every hour. Approximately 30% of all electricity is traded through the spot market the remaining share is traded

through bilateral contracts or long-term contracts. The time constant for the spot market is set to 1 week - enough to give a good estimate of how the capacity factor (capacity utilisation) changes over a year. The market dynamics formulation is given in equation set Market dynamics where spot price is a level that adjusts in proportion to the fractional demand/supply balance.

Figure 16.5 Nord Pool spot market prices and Forward contract prices (2 years ahead) from 01/98 to 12/2000. Source: Nord Pool

a)

Nord Pool market prices
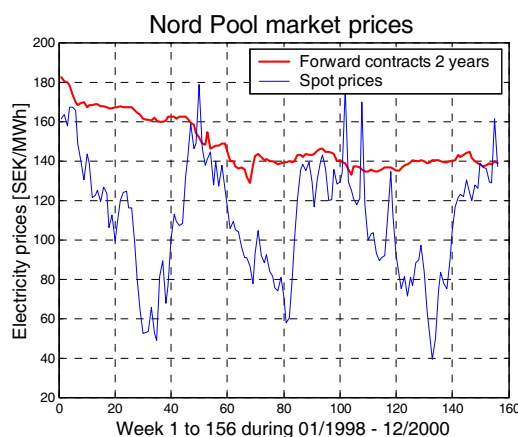
Market dynamics

16.1 $Spot\ price_t = Spot\ price_0 + \int chg\ in\ price_t \cdot dt$ [NOK/MWh]

16.2 $chg\ in\ price_t = Spot\ price \cdot (demand-generation\ tot)/demand \cdot 1/Market\ adjustment\ time$ [NOK/MWh/da]

16.3 $Market\ adjustment\ time = 7$ [da]

16.4 $Spot\ price_0 = 200$ [NOK/MWh]

The Nord Pool futures market represents the joint expectations of market participants where contracts for electricity can be traded up to 4 years ahead. This market is used as an indicator when investment decisions for new capacity are being made. The expected future spot prices are modelled as an adaptive trend extrapolation (Eq. 16.5) of prior average spot market prices (Eq. 16.6) where the smoothing time horizon is 3 years and the forward time horizon is 4 years.

16.5 $Futures\ market\ price = FORECAST(Yearly\ avg\ price\ 3,\ 2)$ [NOK/MWh]

16.6 $Yearly\ avg\ price = SLIDINGAVERAGE(Spot\ price\ 1)$ [NOK/MWh]

16.8   Demand side

The demand side is kept simple in our model as the main focus is on the supply side. Demand is modelled using a Cobb-Douglas function in *equation set Eq.* with a price elasticity of demand equal to -0.3 on a yearly basis although the reported estimates vary from -0.2 to -0.8 (NOU 1998 99; Econ 1999 11; Groenheit & Larsen 2001 46). Simulating over 20 years

demand and price elasticity's will change significantly but in this model we will only address consumer prices influence the demand and keep the reference demand constant over the simulation period. All reference values refer to data from the year 2000.

Demand side

16.7 $demand = Demand\ ref \cdot (Spot\ price/Reference\ price)^{Price\ elasticity\ of\ demand}$ [TWh/yr]

16.8 $Demand\ ref^1 = 420$ [TWh/yr]

16.9 $Reference\ price = 200$ [NOK/MWh]

16.10 $Price\ elasticity\ of\ demand = -0.3$ [1]

16.9   Generation scheduling

Electricity is *not* a commodity and cannot be traded as such. Electricity is a *service* and share many common features of service sectors. In service sectors such as the airline industry services must be produced in a timely manner. In the same way as airlines cannot store flights electricity as a service cannot be stored.

For this reason the generation capacity of electricity must be flexible to meet consumption at all times. The units are scheduled after increasing marginal operational costs as can be seen from *Figure 16.6*. Normalising the below graph with total installed capacity yields the *capacity factor* CF varying between 0 and 1 which is the maximum capacity utilisation.

The stock & flow equations for the generation scheduling are presented in equation set Generation scheduling

Generation scheduling

16.11 $generation\ th = CF \cdot Max\ full\ load\ hrs$ [TWh/yr]

16.12 $CF = GRAPH(Spot\ price_t\ 0\ 50\ \{0\ 0.014\ 0.11\ 0.58\ 0.82\ 0.914\ 0.94\ 0.98\ 1\ 1//$
       $Min:0; Max:1//\})$ [1]

16.13 $Max\ full\ load\ hrs = 8000$ [hr/yr]

The marginal operational costs of hydropower are neglible and hydropower units with reservoirs use some different strategies[2] in production planning. For simplicity hydropower

---

1. Reference demand differs from observed demand in 2000. We deliberately chose a demand that assured the model initially be in long-term equilibrium to ease our analysis.
2. Hydropower units are usually scheduled using the water value method which represents the 'marginal costs' of hydropower. The water value is the marginal change of expected future cumulative profits from releasing water from reservoirs for generation. This problem can be solved as a stochastic dynamic optimsation. A simplified system dynamic representation of the water value method is implemented in the Kraftsim model (Vogstad et al. 2002)

is represented with constant capacity utilisation. Renewable generation however has an element of stochasticity.

16.14 *generation hydro = Hydro·Avg full load hrs hydro*   *[TWh/yr]*

16.15 *Avg full load hrs hydro = 4800*   *[hr/yr]*

16.16 *Capacity hydro = 41600*   *[MW]*

16.17 *generation re = Renewable capacity·Avg full load hrs renewables·(Stochastic generation share·Stochastic variation+(1-Stochastic generation share)) (1)*   *[TWh/yr]*

16.18 *Avg full load hrs renewables = 3350*   *[hr/yr]*

16.19 *Stochastic generation share = 0.6*   *[1]*

16.20 *C.1Stochastic variation of wind was generated from wind energy series collected for Norway. See Tande & Vogstad (2000) for further details*

Figure 16.6 Capacity factor based on marginal production costs of thermal units

a)
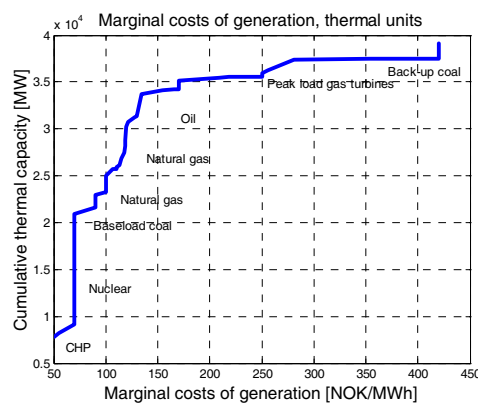
Here, average full load hours represent the average of hydropower units and for renewables they represent the weighted average of present bio energy and wind power. Total generation is the sum of generation from each technology minus grid losses:

16.21 *generation tot = (generation th + generation hydro + generation re)·(1-Grid losses)*
                                                                                             [TWh/yr]

16.22 *Grid losses = 0.1*   *[1]*

An important difference between renewables and thermal generation is the inability to control generation according to prices. Some bio/waste incineration units or small-scale hydropower (defined as new renewable) with reservoirs do operate after marginal costs but it is a good approximation to regard short-term renewable generation as inelastic. In other words renewable technologies lack the *Generation scheduling loop B1*. The level of renewable generation is therefore determined by the long-term *capacity acquisition loop B3* in combination with the stochastic properties of wind and water which is not included in the

simplified model. As we will see later in Eq. 16.12 this has important implications for the TGC market.

16.10 Profitability assessment and capacity acquisition

In the short term electricity generation is adjusted by the processes described by the *Generation scheduling* feedback loop (section 16.9) in response to short-term demand variations. In the long term expectations of future prices govern the investment of new capacity. If the expectations of future spot market prices are significantly higher than the long-run marginal costs (LRMC) of new generation capacity the utility sector will invest in new capacity. Holding the futures market price (Eq. 16.5) up against LRMC for thermal generation (Eq. 16.24) in equation (Eq. 16.23) indicates the *effect of profitability on investment rate* shown in

Figure 16.7 Effect of profitability on investment rate

a)
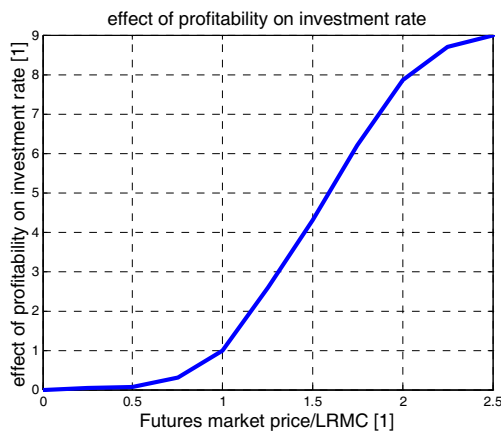
Figure 16.7. When futures market price equals LRMC the effect of profitability on investment rate returns 1 at which the investment rate is in dynamic equilibrium with the depreciation rate (see section 3.4). When the futures market price significantly exceeds LRMC the investment rate increases up to a certain limit that corresponds to a maximum 45% growth rate. Growth within the power industry is limited by the availability of service and material from other industrial sectors. The shape of the curve in *Figure 16.7* can be recognised as a cumulative probability density function that represents the aggregate of a large number of possible profitable projects which would differ in costs. The long-run marginal costs can be represented by a more disaggregated *net present value calculation* including profitability requirements capacity factor investment costs and operational costs which is implemented in the Kraftsim model (see Botterud et al. 2002; Vogstad et al. 2002).

Profitability assessment

16.23 effect of profitability on investment rate th= GRAPH(Futures market price/LRMC thermal 0 0.25 {0 0.03 0.06 0.3 1 2.6 4.3 6.2 7.86 8.7 9//Min:0;Max:10//})   *[1]*

16.24 LRMC thermal = 200   *[NOK/MWh]*

The same structure of profitability assessment applies to renewables except that subsidies are included:

16.25 *effect of profitability on investment rate re = GRAPH((Futures market price + Support scheme)/LRMC renewables 0 0.25 {0 0.03 0.06 0.3 1 2.6 4.3 6.2 7.86 8.7 9})* *[1]*

16.26 *Support scheme = 188*   *[NOK/MWh]*

16.27 *LRMC renewables = 300*   *[NOK/MWh]*

It should be pointed out that the Nord Pool power market is not in long-term equilibrium. A long-term (economic) equilibrium exists when the spot price equals the long-run marginal costs of new generation. For our case the market is in long-term equilibrium when the futures market price equals the long run marginal costs of the generation technologies that is

Futures market price = LRMC thermal = LRMC renewables+subsidies   *(i)*

If this is not the case the installed capacity of thermal and/or renewables and thereby long-term prices will change. To simplify our study we assume the electricity market to be initially in equilibrium at a spot price of 200 NOK/MWh (which is the current observed futures price in the Nord Pool market) and by letting LRMC thermal equal 200 NOK/MWh while LRMC renewables is set to 300 NOK/MWh requiring 100 NOK/MWh in subsidies to maintain present installed capacity.

The futures market price is now approaching long run marginal costs of new generation while recent years have shown average market prices of around 157 NOK/MWh which is far below LRMC for new generation. Noteworthy the futures price history from 1998-2000 (*Figure 16.5*) showed a declining trend. Expectations of lower prices during the first years of deregulation can be attributed to the expectations of increased competition efficiency that more than compensates for reduction of overcapacity. Most partial equilibrium models with endogenous investments assume markets to be in long-term equilibrium although this is rarely the case in real world.

Much of the considerable variation which distorts the price signals is subject to the large variations of hydro inflow from year to year. Hydropower generation can vary as much as +/-40% in a system where hydropower accounts for 61% of electricity generation during normal years of hydro inflow. This problem is not encountered here in our simplified model as we use normal years of hydrological conditions omitting the stochasticity of hydropower. The lifetime of thermal units is set to 30 years and renewables to 20 years. Thus the equilibrium fractional investment rate sufficient to match this rate is 3.33 %/year and 5 %/yr respectively. Initial thermal capacity of 37360 MW and renewable capacity of 5685[1] correspond to the year 2000 situation for the Nord Pool market.

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1. Renewable capacity is calculated as the sum of wind power and biomass installed in 2001 with a corresponding average full load hour utilisation.

Capacity acquisition

16.28 $Capacity\ thermal_t = Capacity\ thermal_0 + \int (new\ capacity\ th_t - depreciation\ rate\ th_t)$ $\cdot dt$ *[MW]*

16.29 $new\ capacity\ th_t = Equilibrium\ fractional\ investment\ rate\ th \cdot effect\ of\ profitability\ on$ $investment\ rate\ th \cdot Capacity\ thermal$ *[MW/yr]*

16.30 $depreciation\ rate\ th_t = Capacity\ thermal/Lifetime\ th$ *[MW/yr]*

16.31 $Equilibrium\ fractional\ investment\ rate\ th = 3.33$ *[%/yr]*

16.32 $Lifetime\ th = 30$ *[yr]*

16.33 $Capacity\ thermal_0 = 37360$ *[MW]*

16.34 $Capacity\ renewables_t = Capacity\ renewables_0 + \int (new\ capacity\ re_t - depreciation$ $rate\ re_t) \cdot dt$ *[MW]*

16.35 $new\ capacity\ re_t = Equilibrium\ fractional\ investment\ rate\ re \cdot effect\ of\ profitability\ on$ $investment\ rate\ re \cdot Capacity\ renewables$ *[MW/yr]*

16.36 $depreciation\ rate\ re_t = Capacity\ re/Lifetime\ re$ *[MW/yr]*

16.37 $Equilibrium\ fractional\ investment\ rate\ re = 5$ *[%/yr]*

16.38 $Lifetime\ re = 20$ *[yr]*

16.39 $Capacity\ renewables_0 = 5685$ *[MW]*

16.11 Simulation run with subsidy scheme

There has been a significant growth in renewables throughout the last years. On average the growth in renewables has been around 10% from 1999 to 2003 for the Nord Pool area. We set the subsidy level to 188 NOK/MWh which is the level of subsidies needed that can maintain this growth rate. Two simulation runs are presented in *Figure 16.8*. Thin lines show a simulation run with constant demand. The bold lines show the response of 10% step increase in demand from 2003. In *Figure 16.8a)* the effect of subsidies is shown on consumer price[1] which coincide with spot price in this case. Demand grows slightly in response to price reductions. Renewable generation increase its share of capacity and to a lesser extent generation while thermal generation must reduce both installed capacity and capacity utilisation (*Figure 16.8b-d*). The second simulation run (bold lines) underlines a major difference between renewables and thermal generation. Thermal generation has larger operational costs (i.e. fuel costs) and generation is scheduled according to their increasing marginal operational costs. Capacity utilisation is therefore governed by the spot price shown as the *B1 generation scheduling* loop in *Figure 16.3*. In contrast renewable generation depends on the intermittent source of wind and water whereas biomass in most cases generates electricity as a by-product of heat and is therefore not sensitive to electricity prices. Renewable generation can only be adjusted by capacity acquisition (loop *B3* in *Figure 16.3*) which involves significant time delays. With respect to demand/supply balance and price stability in the electricity market stochastic generation from renewables does not yet represent insurmountable prob-

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1. The increased taxes on customers from governmental spending on feed-in tariffs is not included here.

lems for the operation of the electricity market[1]. But how would prices in a TGC market form knowing where supply/demand balance must be met on an annual basis but where adjustments in supply involve long time delays in capacity acquisition?   This will be our concern in the following chapter.

16.12 The tradable green certificate market

A TGC certificate is a financial asset that can be traded independently of the physical generation of electricity. The physical supply of electricity is traded in the electricity spot market so that a renewable supplier receives the spot price *plus* the TGC price per MWh generation.

Figure 16.8 CLD of TGC market mechanism

a)
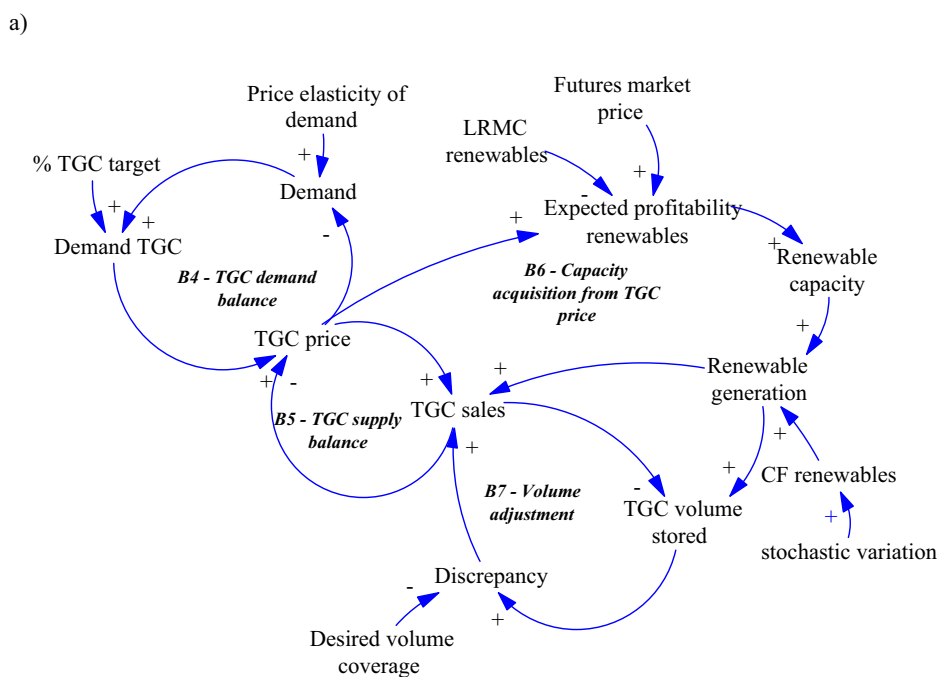
The main idea is to stimulate capacity acquisition of renewables through the TGC price (*loop B6 Figure 16.8*) in order to fulfil the renewable share targets. This mechanism replaces the subsidies (compare with *Figure 16.3*) in the sense that authorities can set a renewables target from which the TGC market will find the sufficient certificate price necessary to reach the

1. In the Jutland area of the Nord Pool market stochastic wind power now comprise more than 40% of total generation which can still be absorbed by the power system but not without countermeasures.

target. The difference between the spot market mechanism and the TGC market mechanism

Figure 16.9 TGC market SFD. Interactions with "Electricity spot market "indicated on the figure. In the following simulations spot market price is constant so that the futures market price is constant. TGC consumption is therefore only influenced by changes in TGC price at this stage. TGC price does however influence consumer price and thereby demand.

a)
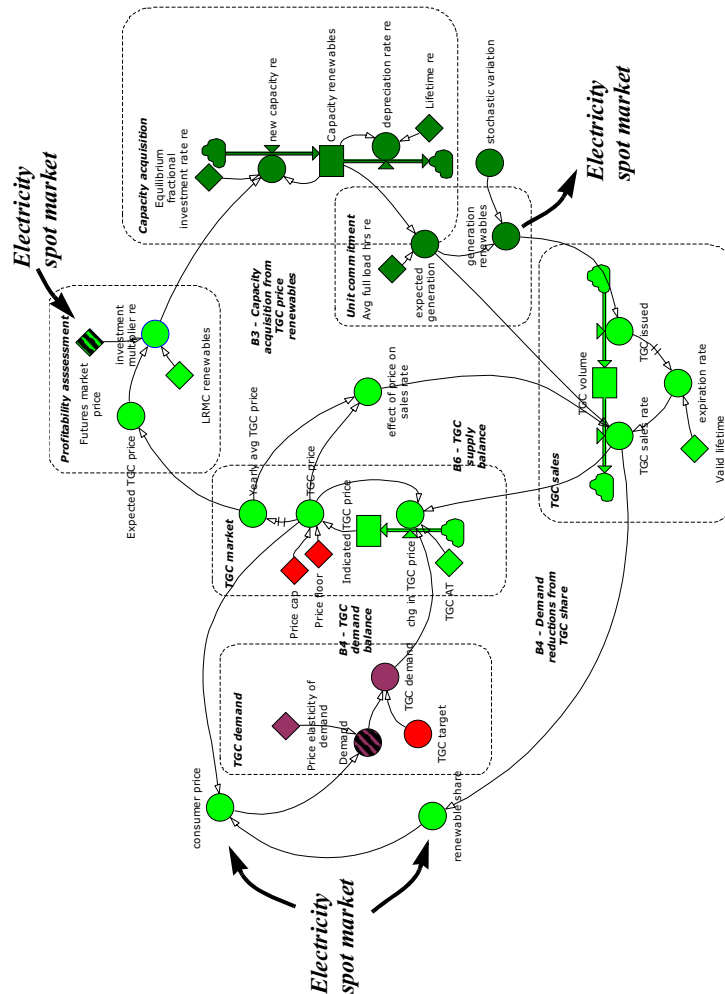
is the lack of short-term regulation by the generation scheduling loop *B1*. As we will see this makes the price formation in the TGC market sluggish because the only way to adjust the supply goes through the capacity acquisition loop *B6 (Figure 16.8)*. The exogenous stochastic variation of primarily wind will also increase the price fluctuations significantly and this is the main motivation for allowing banking of certificates. The compliance period of the Swedish TGC market is 1 year. If TGC obligations are not met during this period consumers are charged by a penalty fee that exceeds the TGC price. *Figure 16.9* shows the stock and

flow diagram of the TGC market where the linkage to the electricity market is indicated. The TGC market sector is similar in structure to the spot price - except that a maximum and a minimum price is introduced in eq. (Eq. 16.40) and the TGC market does not need to clear as frequent as the electricity market. A major difference between conventional sources and renewables is the ability of controlling generation. Wind turbines and small scale hydropower are not operated by marginal production costs but by wind and rainfall whereas bio and waste generate electricity as a by-product and are rarely scheduled by electricity prices but by heat demand.

The purpose of the TGC market is however give long-term price signals for development of new capacity where market-clearing obligations should be met annually. In the absence of a short-run price adjustment process long-term price formation could turn out to be problematic.

TGC market

16.40 *TGC price = MIN(Max price MAX(Indicated TGC price Min price))*   *[NOK/MWh]*

16.41 *Max price = 350*   *[NOK/MWh]*

16.42 *Min price = 0*   *[NOK/MWh]*

16.43 *Indicated TGC price$_t$ = Indicated TGC price$_0$ + ∫ chg in TGC price$_t$· dt [NOK/MWh]*

16.44 *chg in TGC price$_t$ = Indicated TGC price·(TGC demand - TGC sales rate$_t$)/TGC AT*
[NOK/MWh/da]

16.45 *TGC AT = 2*   *[wk]*

16.46 *TGC price$_0$ = 178*   *[NOK/MWh]*

16.47 *Yearly avg TGC price = SLIDINGAVERAGE(TGC price 1)*   *[NOK/MWh]*

The TGC target must be set for some time horizon ahead preferably a rolling time horizon. The (almost) linear curve in *Figure 16.10c)* shows the demand for TGC certificates resulting from a linearly increasing TGC target measured as the percentage TGCs of total generation. For our model we start with the present share of 6 % renewable generation (2003) to reach 24 % in 2020.

TGC demand

16.48 *TGC demand = TGC target·demand*   *[TWh/yr]*

16.49 *TGC target = GRAPH(TIME Starttime 17 {6 24})*   *[%]*

The profitability assessment is the same as defined in equation set *16.23-16.25* except that TGC prices replace the feed-in tariff in the subsidy scheme so that equation *16.26* changes to:

16.50 *Support scheme = TGC price*   *[NOK/MWh]*

Due to the problems of intermittency of wind and small-scale hydro some kind of storage possibility is desirable to ensure a smooth price formation. The Swedish TGC system allow unlimited lifetime of certificates. Another issue is the borrowing of certificates from year to year. We include the possibility of banking in equation set . Certificates are issued upon registered generation (*16.51*). A simple rule of selling TGC's is introduced in eq (*16.56*). Sale of certificates depends on the expected generation and the price of TGC's in the market using a Cobb-Douglas function. With this formulation we assume traders to change their sales rate by 0.8 per cent for each per cent TGC price change relative to the reference value. The refer-

ence value of TGC price is formulated as an adaptive smoothing of approximately TGC prices during the last three years. Alternatively in case of rational traders - the price elasticity of supply would be very high and a reference price that would achieve market equilibrium.

TGC trading

16.51 $TGC\ volume_t = TGC\ volume_0 + \int (TGC\ issued_t - TGC\ sales\ rate_t) \cdot dt$ *[TWh]*

16.52 $TGC\ volume_0 = 25$ *[TWh]*

16.53 $TGC\ issued_t = generation\ re$ *[TWh/yr]*

16.54 $TGC\ sales\ rate_t = MAX(expected\ generation \cdot effect\ of\ TGC\ price\ on\ sales\ rate\ expiration\ rate)$ *[TWh/yr]*

16.55 *Min sales time = 1*   *[wk]*

16.56 *effect of TGC price on sales rate* $= generation\ re \cdot (TGC\ price/Yearly\ avg\ TGC\ price)^{Price\ elasticity\ of\ TGC\ supply}$ *[TWh/yr]*

16.57 *Price elasticity of TGC sales = 0.8*   *[1]*

16.58 *expiration rate = DELAYMTR(TGC issued, Valid lifetime, 3)*   *[TWh/yr]*

16.59 *Valid lifetime = 1e13*   *[yr]*

16.13 TGC market simulation results

The below simulations show the dynamics of the TGC market defined in the equation sets -. As can be seen in *Figure 16.10a)* The TGC prices oscillates. This is mainly due to the time delay in the expectation formation. We did not explicitly model the time delays involved in the capacity acquisition[1]. However these time delays are implicitly modelled in the "effect of profitability on investment rate" function (see *Figure 16.7b)*.

Figure 16.10a) show long-term fluctuation of TGC prices. This behaviour is attributed to the time delays involved in forming expectations about prices and the time delays for new capacity. The declining price trend is explained by the price rise from increasing obligations to purchase TGC's which makes consumer prices higher. In *Figure 16.10b)* we can observe how the physical generation of renewables deviate from the TGC target in the (almost) linear curve starting from 2003. Sales rate and TGC demand matches perfectly because deviations when storing and forwarding certificates are possible as in *Figure 16.10b)*. The development of renewables under a subsidy scheme is also shown for comparison as a reference case. With one-year average clearing time of the market the TGC sales rate also deviates from the TGC demand. A smaller TGC Adjustment time (*16.45*) results in smaller deviations of TGC demand and TGC supply but TGC prices fluctuations will increase both in amplitude and frequency. Similarly other delays along the capacity acquisition loop will influence the prices and TGC demand/supply balance such as the expectations of future prices and the time delays of capacity acquisition.

The supply and demand obligation at the beginning of the TGC period will be important. If there is a big gap between generation of renewables and TGC obligations prices start rising (or down if there is overcapacity) because it will take at least two years before sufficient capacity can become available. This effect is more dramatic with restrictions on borrowing and

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1. Time delays for building new renewable capacity amounts to 1.1 year for applications and at least half a year for construction.

Figure 16.10TGC market dynamics introduced in 2003. Constant wind and constant electricity spot price. Reference curves are market with * and corresponds to the development of renewable generation and capacity with a fixed feed-in tariff of 178 NOK/MWh.

a) TGC price
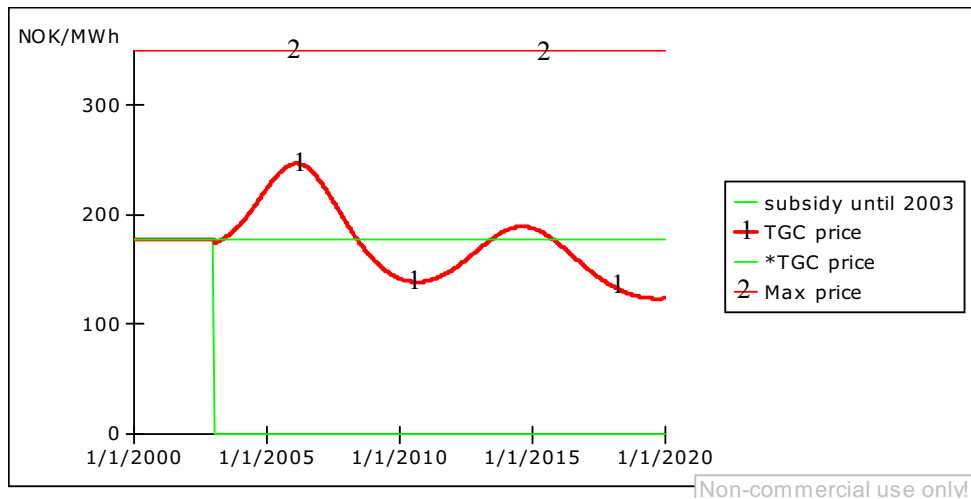
b) TGC volume. Initial volume equals 1 year of demand
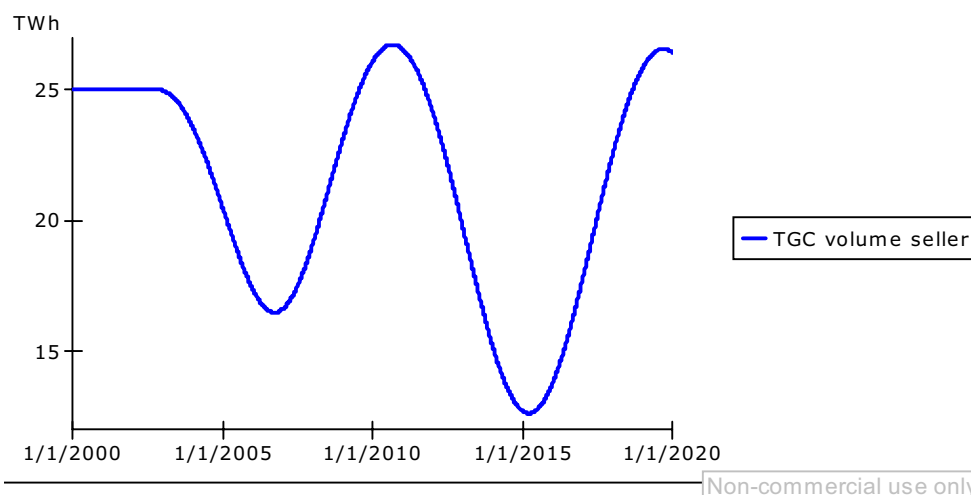
Figure 16.10TGC market dynamics introduced in 2003. Constant wind and constant electricity spot price. Reference curves are market with * and corresponds to the development of renewable generation and capacity with a fixed feed-in tariff of 178 NOK/MWh.

c) TGC demand sales rate and physical generation. Reference (*) shows generation development under the subsidy scheme.
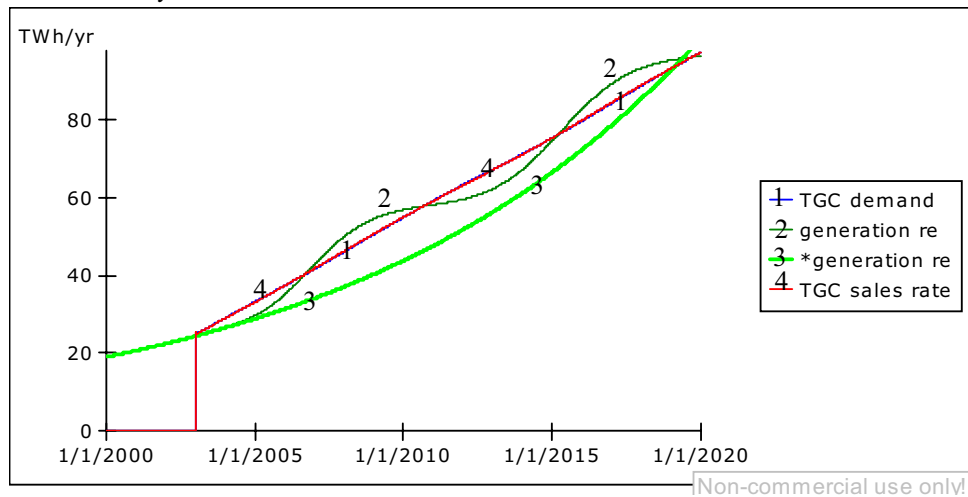
d) Renewable capacity. Reference (*) shows capacity development under the subsidy scheme
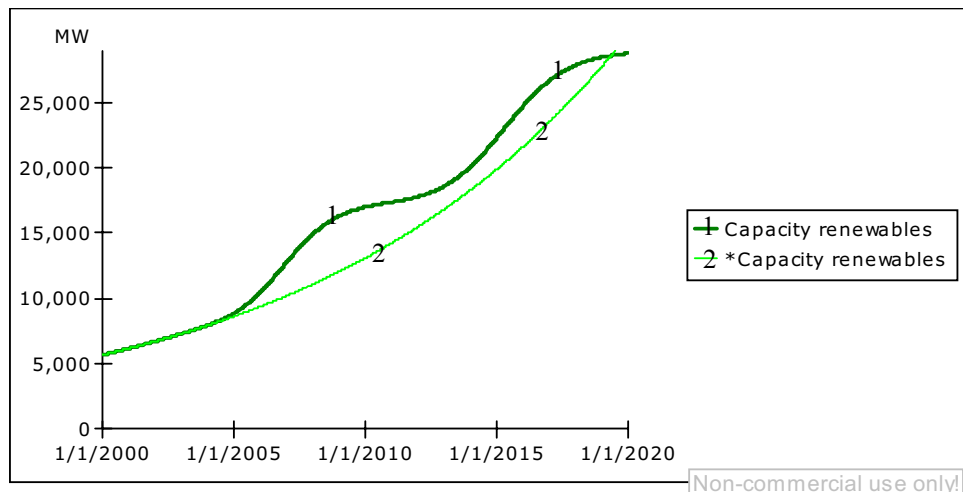
banking. This indicates the importance of setting realistic targets for TGC's in the beginning and to allow flexibility in terms of banking and borrowing. Constraints on prices are also important to protect consumers from having prices skyrocketing. It would also be important to secure or guarantee prices during the first years of the TGC market. This issue has also been a major concern in the discussion of the implementation of TGCs in Denmark and Sweden. Both countries have some subsidy scheme for various technologies. Current proposals are to establish TGC price caps and price floors that gradually will be phased out during the first years.

As a result of the price fluctuations capacity develops in more or less pronounced boom and bust cycles (see *Figure 16.10d)*.

Figure 16.11b) shows the variations in TGC volume during the planning period. The main purpose of banking is to cope with the intermittency of renewable generation. Various options on banking and borrowing could alter the TGC sales strategy previously defined in equation set . Suppose unlimited banking is allowed but no borrowing. If TGC suppliers decided to reduce their sales of TGC's prices would rise while there is few possibilities to increase the supply of TGC in the short run until sufficient capacity is added.

To study the possibilities for market power and trading strategies under various market designs we develop a more detailed description of buying and selling in the TGC market.

16.14 Market design

The intermittency of renewables has been the main concern in the discussion of price volatility of the TGC market.

Price volatility has been discussed qualitatively in Nielsen & Jeppesen (2003) Bye et al (2002) and in the Swedish white paper SOU 2001:77. The discussions take a traditional economic point of view and the main concern in this discussion is the inelastic curves of supply and demand. As discussed in section 16.9 renewables do not operates after marginal costs and the adjustments of the supply curve comes from investments in new capacity involving time delays of permits and construction. Price will therefore fluctuate with the variability of generation from year to year for the consumers to meet their yearly obligations. Several options are considered to reduce the price volatility of TGC's:

Figure 16.11 Price volatility in the TGC market

a) Inelastic demand and supply

b) Elastic demand and supply from banking borrowing
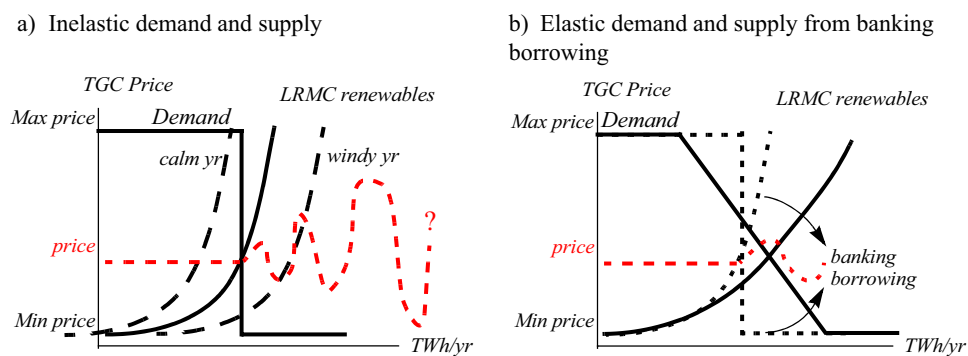
- Include different technologies with operational costs.

By including biomass that operates after marginal costs the problem of price volatility can be reduced. However the potential for such technologies are questioned. Biomass and waste incineration are usually CHP[1] plants generating electricity as a by-product of their heat generation. Furthermore income from electricity generation would come from both the spot market and the TGC market so the likelihood that such units would be sensitive to TGC prices are questionable.

- Maximum and minimum prices

_____

1. Combined heat and power generation units.

Price caps and price floors secure the consumer/producers against high/low prices (see *Figure 16.11a)*. This arrangement is especially important in the introduction phase to reduce risk for investors.

- Banking and borrowing

To improve the stability of supply certificates can have a valid lifetime longer than the yearly compliance period of consumers. This mechanism is referred to as banking where producers and consumers can choose in periods of low prices (i.e. windy years) to store certificates for later years. Banking is assumed to have a price smoothing effect and in the proposed Swedish TGC market certificates have unlimited lifetime. According to the above-mentioned studies the price elasticity of the supply and demand curves increase as illustrated in *Figure 16.11b)*. Similarly allowing participants to fulfil their obligations in the future (similar to futures contracts) would also increase the elasticity's of demand and supply. The disadvantage of borrowing is that some regulation must secure that these future obligations are met for instance by imposing penalties. Several arrangements of borrowing mechanisms are possible but the principle remains the same that is to increase flexibility of supply by allowing trading with future TGC production.

16.15 Laboratory experiments of TGC trading

The European Renewable Electricity Certificate Trading Project (RECeRT) took on the experimental approach to study the influence of price caps banking and borrowing on price volatility in a TGC market. The first experimental economics study reported in Schaeffer & Sonnemans (2000) - showed that unlimited banking in combination with high price caps could induce price crashes and increased volatility rather than the opposite.   Price caps and borrowing and banking all had an influence on the price volatility. The best results were obtained when only borrowing was allowed. A larger internet based experimental study involving over 140 participants was also conducted under the same project and the resulting price history is shown in *Figure 16.13b)*. Unfortunately the market turned out to be short most of the simulation period and the TGC prices naturally settled one the maximum price which makes this experiment inconclusive with respect to price volatility. Another initiative the RECS project has been trading TGC's at an internet- based exchange for several years but they did not report on price formation.

Figure 16.12 Laboratory experiments on TGC trading at NTNU

At NTNU we set up a network simulation game and invited (wind) power engineers and energy policy administrators for a laboratory experiment on TGC trading. The model used is the same as the TGC market model shown in *Figure 16.9* except that 5 buyers and 5 sellers interactively controlled the purchase and sales rate for each year through a user interface with relevant information on price TGC's issued volume etc. (see *Figure 16.12*). The model made investment decisions endogenously.

Figure 16.13 Laboratory experiment results of TGC markets

a) Price crash from the NTNU experiment. Low sales rate in the first years lead to persistent high prices and over investment in new capacity which caused the price crash in the subsequent years.
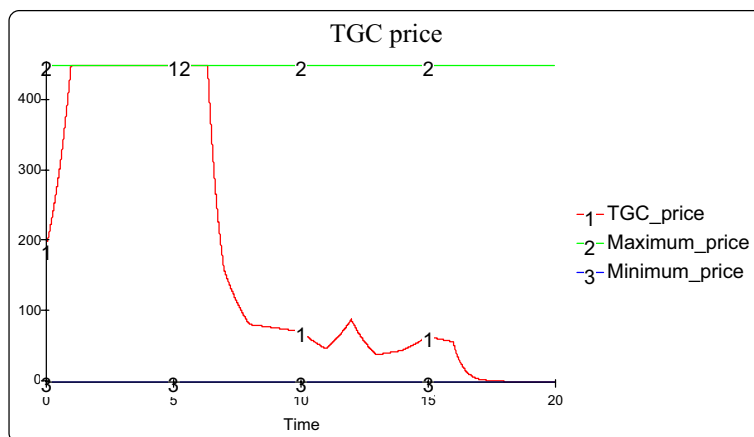
Figure 16.13Laboratory experiment results of TGC markets

b) Price formation in the ReCERT internet experiment involving 140 participants. Prices stabilised on maximum price as the market was short throughout the whole simulation period. With respect to price stability this experiment was therefore inconclusive (Source: ReCERT 2001)
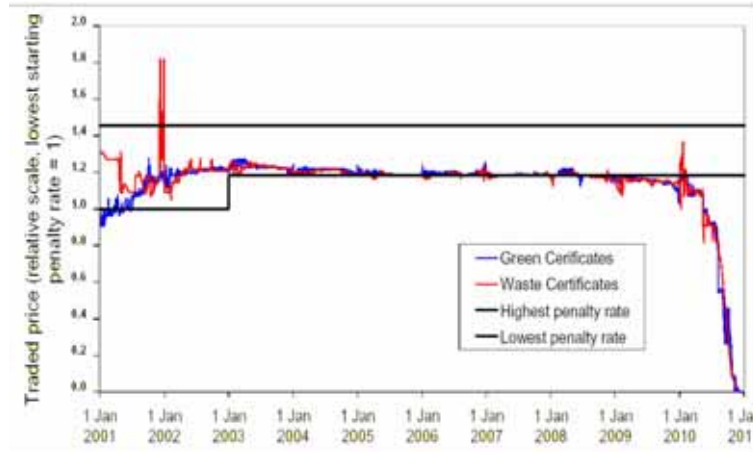
c) Price crash in a computer laboratory experiment. 100% banking and 50% borrowing allowed. Equilibrium price indicated by lower horizontal line. Upper horizontal line indicates maximum price (penalty). (Source: ReCERT Schaeffer & Sonnemans 2000)
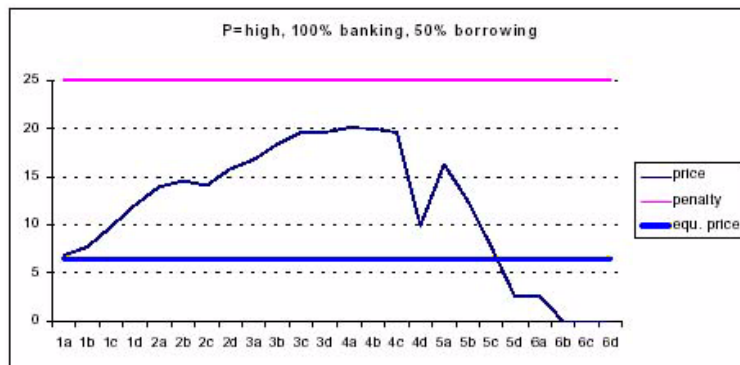
d) Same experiment as in d) but with a lower maximum price and only borrowing This market design lead to a price formation close to equilibrium.

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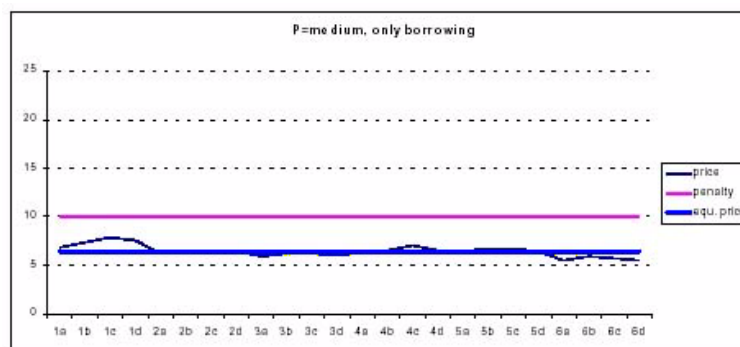
16.16 Modelling trading in a TGC market

Trading is constrained by the valid lifetime of a certificate (banking) and the possibilities of borrowing. In addition price caps represent constraints on the TGC price and buyers need to meet their TGC obligations defined as a percentage of electricity sold to the consumer.

Trading with TGC certificates can be viewed as a problem of profit maximisation for the seller and a cost minimisation of the buyer. The optimisation problem is however not simple depending on the market design. If the TGC's are valid for one year we should expect all certificates to be sold that year and the price will then depend upon the conditions of wind and rainfall. If on the other hand certificates have unlimited lifetime - it is possible to hold back certificates over longer periods of time which opts for various trading strategies. The price of certificates in the long run should converge to the long-run marginal costs of new renewables but since developing new capacity takes time and TGC obligations must be met every year it is possible to hold back certificates to stimulate price increases and prices can persist far from equilibrium price. If borrowing is possible holding back certificates would lead to more borrowing if prices exceed the expected long run marginal costs of new generation and thus reduce market power from suppliers.

Figure 16.14 shows the CLD of buying and selling in the TGC market. The market consist

Figure 16.14
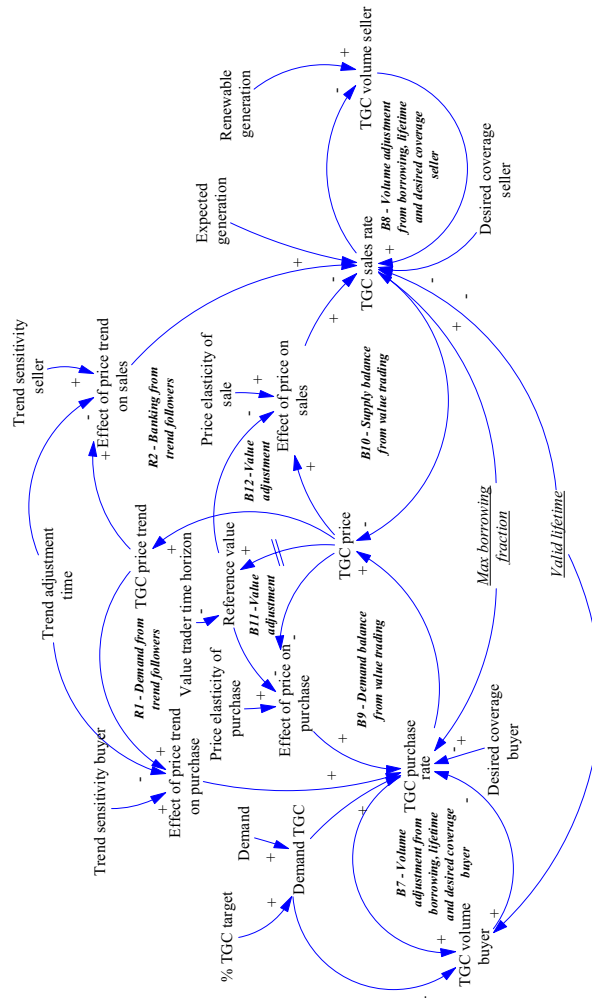
of buyers and sellers each constrained by possibilities of borrowing and banking. These regulations constrain their TGC volumes represented by *Loop B7 and B8.* Their respective sales and purchase strategy is represented by a combination of two loops: We hypothesize Value trading *(B9 B10)* and trend following *(R1 R2)* to be the trading strategy of buyers and sellers in the TGC market. Taking the seller as an example value trading means that you have a reference value to which you compare the market price. If the market price is higher than your evaluation of the value of the certificate you will sell more otherwise you will sell less. On the contrary trend trading is a reinforcing process. The steeper the trend the less you will sell because you can probably get a higher value for the certificate later on which will reinforce the trend further.

The stock and flow diagram is shown in *Figure 16.15*. Equation set TGC trading seller defines the sellers TGC volume management. Issuing of certificates equals the generation from renewables whereas the sales rate of TGC's take the expected generation from renew-

ables as a reference (eq. *16.63*) adjusted by the effect of price the effect of trend and the constraints imposed on borrowing banking and volume control due to risk aversion. If certificates expire they will be sold immediately according to eq. *16.63* and *16.69*. When borrowing limits are exceeded (eq. *16.64- 16.68*) the sales rate is adjusted to keep within limits. The maximal borrowing fraction is defined as a fixed percentage of the expected generation (eq *16.67*).

TGC trading seller

16.60 *TGC volume seller$_t$ = TGC volume seller$_0$ + ∫ (TGC issued$_t$ - TGC sales rate$_t$) ˙dt*
          [TWh]

16.61 *TGC volume$_0$ = 12.5*   *[TWh]*

16.62 *TGC issued$_t$ = generation re*   *[TWh/yr]*

16.63 *TGC sales rate$_t$ = MAX(expected generation˙effect of TGC price on sales rate˙effect of TGC trend on sales rate-adj for borrowing seller+TGC vol adj seller expiration rate)*   *[TWh/yr]*

16.64 *adj for borrowing seller = MAX(borrowing margin/Borrowing AT 0)*   *[TWh/yr]*

16.65 *Borrowing AT = 1*   *[mo]*

16.66 *borrowing margin = (max borrowing seller - TGC volume seller)*   *[TWh/yr]*

16.67 *max borrowing seller = Fraction max borrowing˙expected generation*   *[TWh/yr]*

16.68 *Fraction max borrowing = -0.5*   *[TWh/(TWh/yr)]*

16.69 *expiration rate = DELAYMTR(TGC issued Valid lifetime 3)*   *[TWh/yr]*

Figure 16.15Stock and flow diagram representing buying selling and trading strategies of TGC certificates.

The same structure applies to buyers of TGC's defined in equation set TGC trading buyer. The buyer must control his TGC volume through purchases whereas the demand obligations control the consumption rate of TGC's. We assumed that the buyer adopted the same strategy as the sellers that is value trading and trend following.

TGC trading buyer

16.70 $TGC\ volume\ buyer_t = TGC\ volume\ buyer_0 + \int (TGC\ purchased_t - TGC\ consumption\ rate_t) \cdot dt$ [TWh]

16.71 $TGC\ volume_0 = 0$ [TWh]

16.72 $TGC\ issued_t = TGC\ purchase\ rate$ [TWh/yr]

16.73 $TGC\ purchase\ rate_t = MAX(TGC\ demand \cdot effect\ of\ TGC\ price\ on\ purchase\ rate \cdot effect\ of\ TGC\ trend\ on\ purchase\ rate + adj\ for\ borrowing\ buyer + TGC\ vol\ adj\ buyer\ expiration\ rate)$ [TWh/yr]

16.74 $adj\ for\ borrowing\ buyer\ seller = MAX(borrowing\ margin\ purchase/Borrowing\ AT\ 0)$ [TWh/yr]

16.75 $borrowing\ margin\ buyer = (max\ borrowing\ buyer - TGC\ volume\ buyer)$ [TWh/yr]

16.76 $max\ borrowing\ buyer = Fraction\ max\ borrowing \cdot TGC\ demand$ [TWh/yr]

16.77 $expiration\ rate\ buyer = DELAYMTR(TGC\ purchased\ Valid\ lifetime\ 3)$ [TWh/yr]

In the following we will discuss the trading strategies more closely

The rational expectations paradigm assumes that traders have complete knowledge of all the economic relationships they have access to all available information that needs to be taken into consideration and they have enough time and resources to do so in order to make optimal decisions on buying and selling. Any price fluctuations are exogenously caused by new information of fundamentals (i.e. breakthrough's in technology or excess generation of TGC from last month) The rational expectations paradigm can be a sufficient approximation in many cases but this assumption does not always hold.

A more realistic assumption is the paradigm of bounded rationality where traders are restricted in terms of resources time and cognitive capacity to make optimal decisions on buying and selling. Their decisions are based on a limited selective set of information available to them. System dynamics and cognitive science provide us with theory to model boundedly rational agents by capturing their decision rules. Heuristic rules for trading could be inferred from analysing data from the laboratory experiments on TGC markets. Unfortunately the quality of the conducted experiment at NTNU was not sufficient in order to use it for estimating decision rules and there were too few experiments. Still some observations and experience can be used to hypothesize their decision rules.

Price dynamics of common trading strategies in asset markets has been studied in emerging fields of economics (see for instance Farmer & Joshi 2000 and Gaunersdorfer 2000). Their studies show that simple and commonly used trading strategies based on adaptive belief endogenously generate price fluctuations and statistical behaviour of prices as those observed in real world markets. This indicates that representation of simple decision rules can capture characteristic behaviour of markets that in turn can be utilised for analysis and design. In the following we will describe two trading strategies namely *value trading* and *trend following*.

16.17 Value traders

Value traders make subjective evaluation of the "fundamental" value of the asset and believe the market sooner or later will adjust to this value. They attempt to make profits by selling if they think the market is overpriced and buying if they believe the market is under priced. These traders are called "fundamentalists" in the sense that they make an assessment of the value of a TGC asset from the "fundamentals" of the market. In a TGC market fundamentals are information about new project developments permits contracts cost of new

technologies etc. The "fundamentals" of renewables are fairly reliable in comparison to stock markets. However such analyses would require time and resources. The most influential source of information is perhaps recent prices and thus we can represent the fundamental value denoted as *Perceived TGC value* as an adaptive expectation of recent prices in eq Eq. 16.79. where the *Value trader adjustment time* is the average smoothing time which should be of the same magnitude as the time delays involved in construction of new capacity because only new capacity can adjust price in the long run. The price elasticity of TGC supply indicates how many per cent a seller would change his sales in response to price changes. The effect of TGC price on sales rate function is a multiplier used in the sales and purchase policies.

Value trading

16.78 *effect of TGC price on sales rate = (TGC price/Reference price)$^{\text{Price elasticity of TGC supply}}$*
                                                                                                                    [TWh/yr]

16.79 *Reference TGC price = DELAYINF(TGC price Value trader AT)*   *[NOK/MWh]*

16.80 *Value trader time horizon = 3*   *[yr]*

16.81 *Price elasticity of TGC sales = 1.5*   *[1]*

The same structure applies to buyers of TGC's as well except for a change in parameters. We assume the same parameters as for sellers except for the price elasticity of demand

16.82 *Price elasticity of TGC demand = -1.5*   *[1]*

16.18 Trend followers

Trend followers have shorter time horizon than those of value traders. They believe that prices will fluctuate but that the market has some inertia that can be exploited. A seller would then hold his position of TGC's if the trend is positive and sell when the trend is negative. Conversely a buyer would hold his position when prices are falling and buy when prices are rising:

Trend followers

16.83 *effect of price trend on sales = (1+TGC price trend)$^{\text{Trend elasticity}}$*   *[1]*

16.84 *Price trend = TREND(TGC price Trend AT)*   *[1/yr]*

16.85 *Trend adjustment time = 1*   *[yr]*

16.86 *Trend elasticity = 2*   *[1]*

The trend is observed over some time interval. It is not likely that short-term price fluctuations would occur in the TGC market as demand obligations must be met once a year but the trend horizon must be less than the expected average time to add new capacity. The trend adjustment time is therefore set to 1 year in eq (Eq. 16.85).

The NTNU experiment strongly suggested that the trend strategy to be dominating perhaps because this is the simplest strategy and only requires information on previous prices. We hypothesize that traders would both look to the value and to the trend when trading in a TGC market. If the price is high and the trend is positive the seller would probably sell less than if the trend is pointing downwards. Similarly if the price is low and the trend is pointing

up the seller would be more inclined to wait than if the trend is going down. This trading strategy is represented through eqs Eq. 16.63 and Eq. 16.73:

TGC sales rate$_t$ = f(expected generation re·effect of TGC price on sales rate·effect of TGC trend on sales rate ... other factors ...)

In asset markets trend trading and value trading is separated by their difference in time horizon. In a TGC market however the slow dynamics of new capacity makes these strategies relevant on the same time scale.

16.19 Managing risk by controlling the TGC volume

Using the trend and value strategies TGC volumes could grow very large which represent large risks if the market should crash. Neither the buyer nor the seller should keep large volumes of TGC's over a long period. This risk aversion can be taken into account by adjusting the TGC volume with an adjustment time of up to 3 years as in equation set Eq. -Eq. . The buyer would like to have some coverage of TGC's

Volume adjustment seller

16.87 *TGC vol adj seller = (SLIDINGAVERAGE(TGC vol seller 1) - desired volume seller)/ Volume adj time seller*   *[TWh/yr]*

16.88 *desired volume seller = expected generation·Desired coverage time*   *[TWh]*

16.89 *Desired coverage time seller = 6*   *[mo]*

16.90 *Volume adj time seller = 3*   *[yr]*

Volume adjustment seller

16.91 *TGC vol adj buyer = (SLIDINGAVERAGE(TGC vol buyer 1) - desired volume buyer)/ Volume adj time buyer*   *[TWh/yr]*

16.92 *desired volume buyer = TGC demand·Desired coverage time buyer*   *[TWh]*

16.93 *Desired coverage time buyer = 6*   *[mo]*

16.94 *Volume adj time buyer = 3*   *[yr]*

16.20 Simulation results

Consider the simplest case withouth borrowing and 1 year certificate valid lifetime. We assume a price elasticity's of -1 and 1 respectively for the TGC price elasticty of buyer and seller. No trend following strategy is applied. *Figure 16.17* shows a Monte Carlo simulation based on these assumptions where wind energy accounts for the stochasticity from the renewables (see *Figure 16.17a)* Prices increase during the first years peaks and decline well below the equilibrium price of 178 NOK/MWh. In the calmest years prices hit the price cap of 350 NOK/MWh. The average price development however can be compared with that of

the TGC market model in section 16.12 (see *Figure 16.10*). This market design does not al-

Figure 16.16

a) Normalised wind energy used to represent stochastic generation. Wind energy series adapted from Tande et. al & Vogstad 1999)
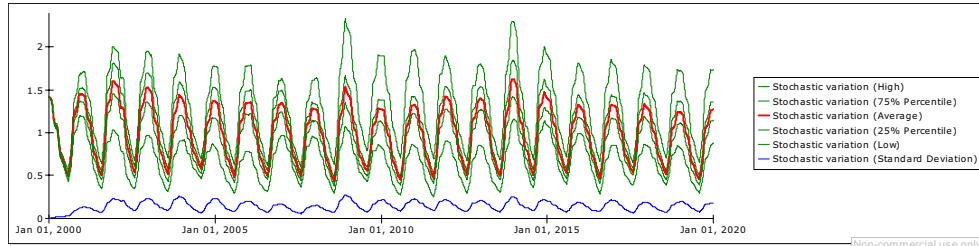
low for banking and borrowing as can be seen by buyers' TGC volume and sellers TGC volume in *Figure 16.17b)-c)*

Figure 16.17 TGC 1 year valid lifetime no borrowing. No trend followers
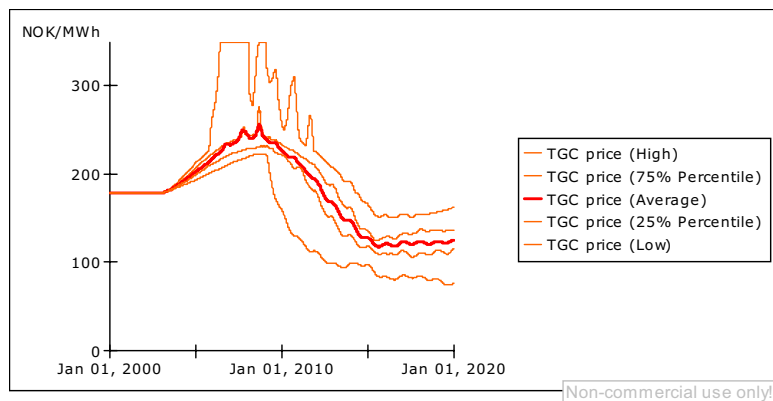
a) Price

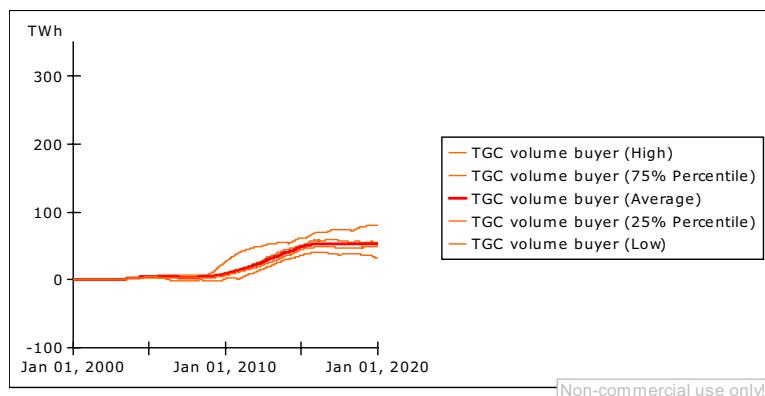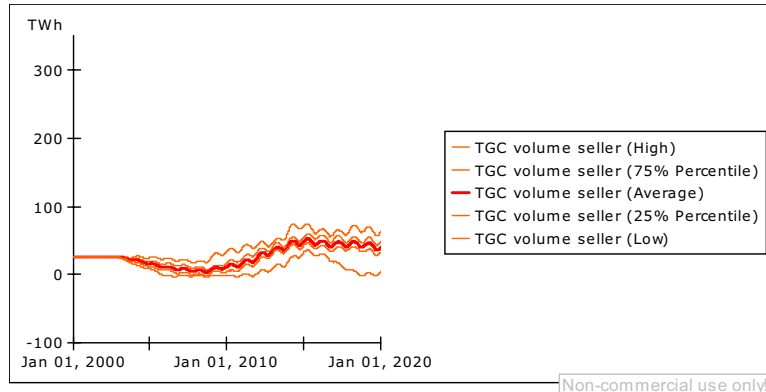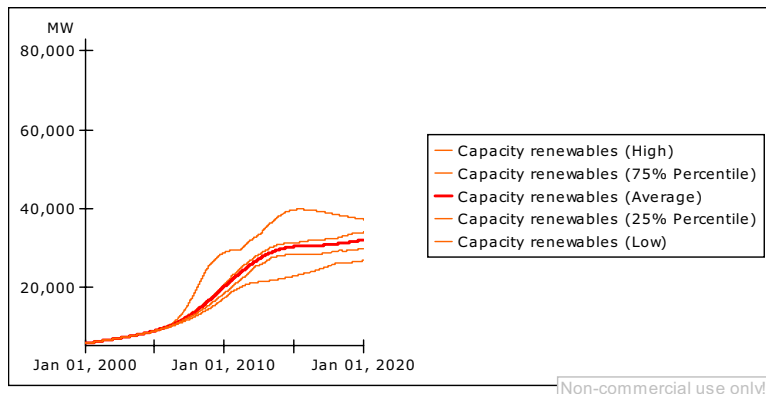b) Buyers volume is restricted by expiration rate

Figure 16.17TGC 1 year valid lifetime no borrowing. No trend followers

c) Sellers volume is restricted by expiration rate

d)
e) Capacity development

When we allow for banking *Figure 16.18* shows almost the same behaviour during the first years since there is shortage of renewable capacity in proportion to the TGC target. After 2010 buyer's and seller's start banking. No trend strategy is used in this simulation. It appears that banking does not reduce price volatility during the first years due to the initial capacity deficit during the first years When there is a surplus of TGC's banking tend to smooth prices to some extent (compare end periods of *Figure 16.17a Figure 16.18a)*.

In the next simulations we include the trend strategy. Traders now consider both the *price* and the *trend* of the TGC when buying and selling. The price elasticity of trend is set to 2. Thus 1 % price increase will increase the sales rate by 1 % and 1% increase in trend will *reduce* the sales rate by 2 %. Similarly the buyer will increase his purchase rate when the price is dropping but if the trend is negative he will delay his purchase to wait for even lower prices. If we compare *Figure 16.19d* with *Figure 16.18d* we can observe that the seller is slightly more restrictive in selling which results in a deficit on the buyer side (compare *Figure 16.19c* with *Figure 16.18c*) - enough to drive up prices in *Figure 16.19a* where the average price nearly hits the price cap. The conditions of capacity deficit in the start of the TGC period triggers the trend following strategy. In the case of initial overcapacity (or TGC targets less ambitious) a downward price trend would not have caused a similar problematic price drop because the buyers are anyhow obliged to purchase certificates. Just after the price peaks buyers begin to accumulate certificates due to the negative trend.

Figure 16.18Infinite banking no borrowing. No trend followers
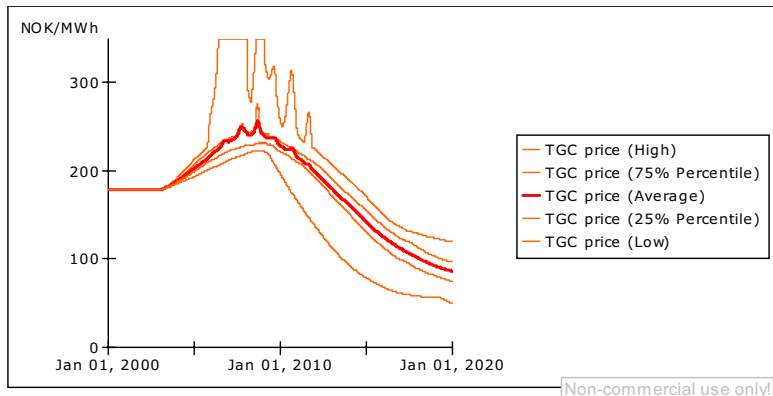
a) Price

b) TGC volume buyer
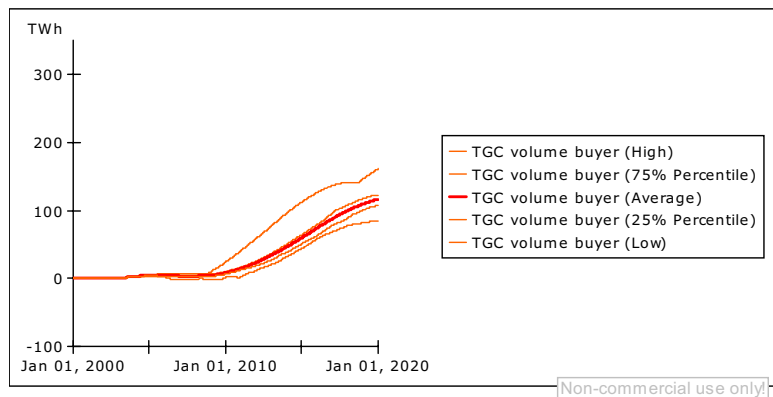
Figure 16.18Infinite banking no borrowing. No trend followers

c) TGC volume seller
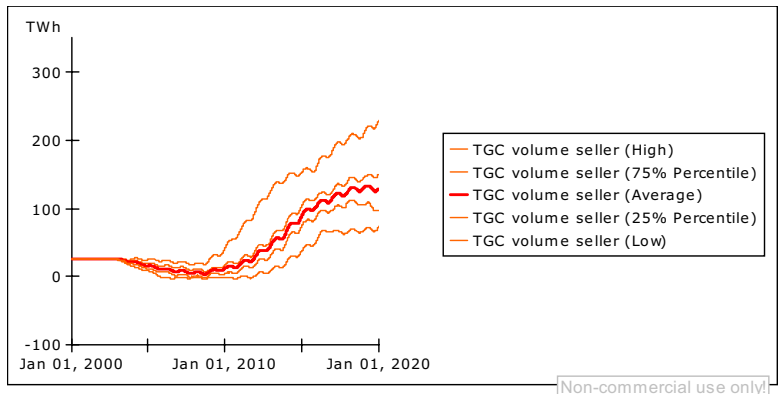
TWh

- TGC volume seller (High)
- TGC volume seller (75% Percentile)
- TGC volume seller (Average)
- TGC volume seller (25% Percentile)
- TGC volume seller (Low)

Non-commercial use only!

d) Capacity development

MW

- Capacity renewables (High)
- Capacity renewables (75% Percentile)
- Capacity renewables (Average)
- Capacity renewables (25% Percentile)
- Capacity renewables (Low)

Non-commercial use only!

Figure 16.19Infinite banking no borrowing with trend strategy

a) Price

NOK/MWh

- TGC price (High)
- TGC price (75% Percentile)
- TGC price (Average)
- TGC price (25% Percentile)
- TGC price (Low)

Non-commercial use only!

Figure 16.19 Infinite banking no borrowing with trend strategy

b) TGC volume buyer

c) TGC volume seller
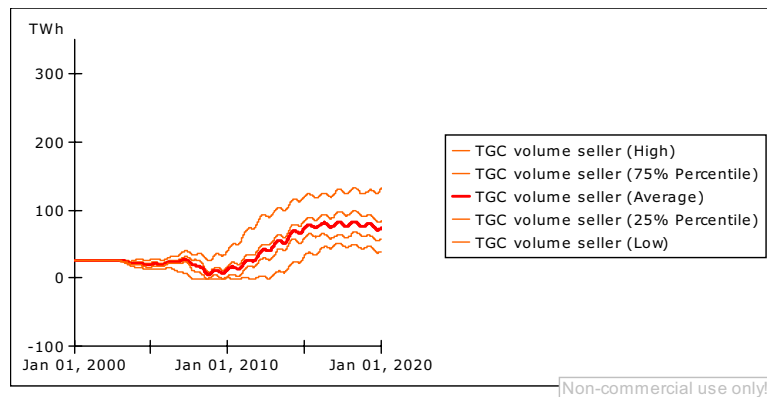
d) Capacity development

To explore these strategies furhter *Figure 16.20* shows a typical simulation run with the same market design presented in the Monte Carlo simulation. In *Figure 16.20b* sellers start with an initial TGC volume of 25 TWh TGC's and they do not increase sales rate even though the prices are rising. In 2006 buyers cannot fulfill their obligations and their volume is negative while the sellers in fact choose to bank TGC's. The price hits the price cap and the sellers reduce their TGC volume towards 2010 but by this time a significant amount of capacity has been developed and prices fall below the initial equilibrium price of 178 NOK/

MWh. *Figure 16.20c* show the relative effect of the trading strategies on sales rate. In this simulation run the TGC trend effect dominates the sales strategy while the value trading strategy serves to moderate the trend strategy.

Figure 16.20 Typical simulation run infinite banking no borrowing with trend strategy.

a) Price
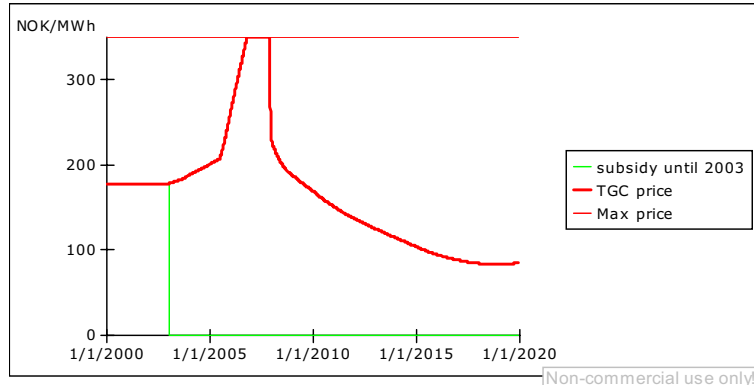
b) Effect of value and trend strategies on sales rate

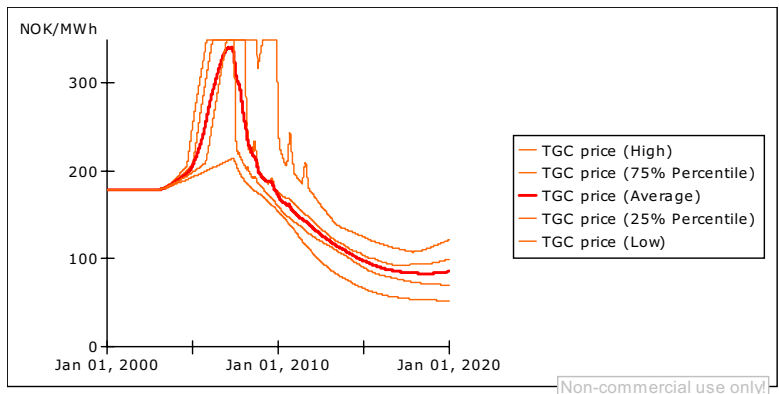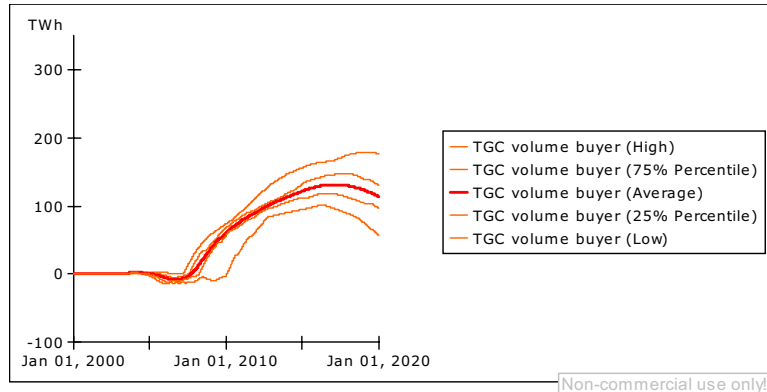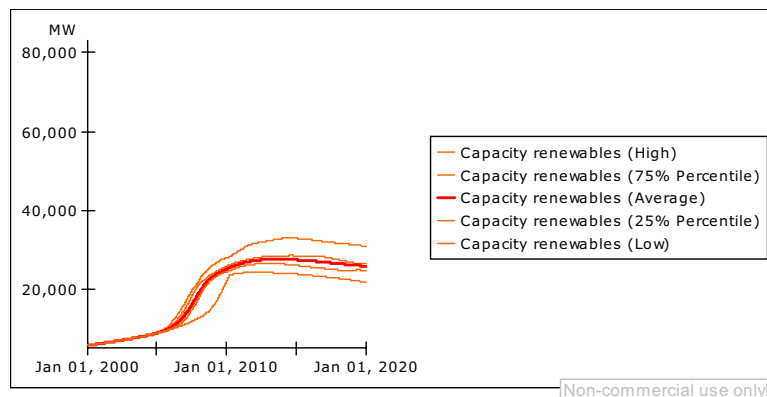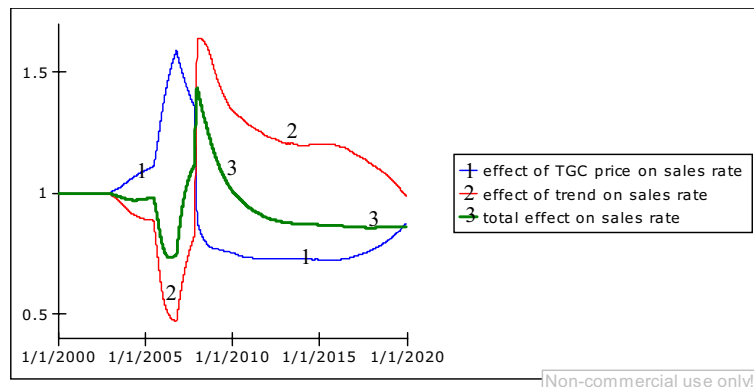**Figure 16.20Typical simulation run infinite banking no borrowing with trend strategy.**

c) TGC volume buyer and seller
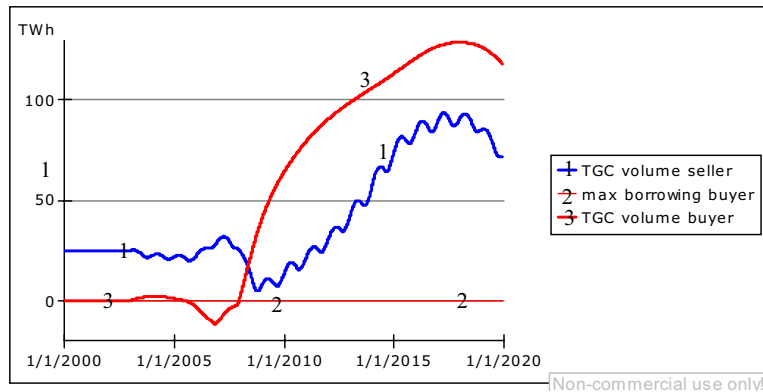
d) Capacity development
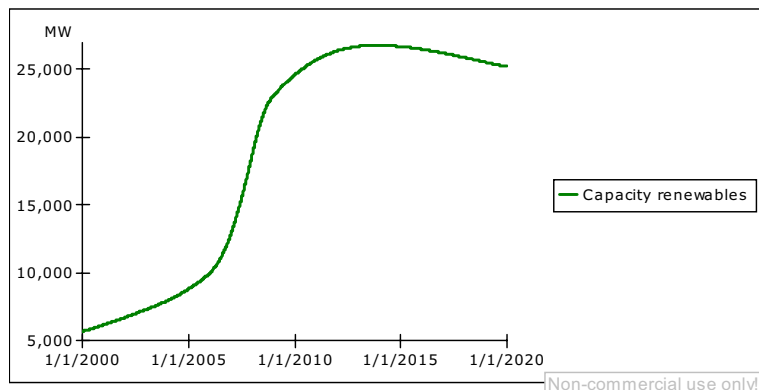
Now, lets consider allowing 50% borrowing of certificates that is - buyers and sellers can borrow up to 50% of their respective yearly obligation and present TGC yearly generation. The results in *Figure 16.21* shows that prices show less volatility in response to stochastic variation from in renewable generation.

The trend strategy in a market with up to 50% borrowing does not have the same impact as when only banking is allowed. In *Figure 16.22b* buyers now borrow certificates as prices rise. Comparing with *Figure 16.22c* the seller tries to reduce his sales rate during the first years but this strategy does not have a sufficient impact on the price any more. And after some years the value trading strategy becomes the dominant one.

If we remove the possibilities for banking (*Figure 16.23*) the results show are similar except that less TGC's are stored at the buyer in the end of the TGC period. Price variations from year to year do not seem to be significant compared with the simulation runs including borrowing.

The results of these simulations suggest that allowing banking to reduce price volatility from the stochastic variation of renewables could in fact *increase* price volatility that arise from the strategic behaviour that becomes available. This effect does not appear if we assume traders only to use the value trading strategy described in *16.17*. If however the traders also apply some trend following strategies as described in *16.18*   price crashes will likely to oc-

Figure 16.21 Banking 50% borrowing trend

a)
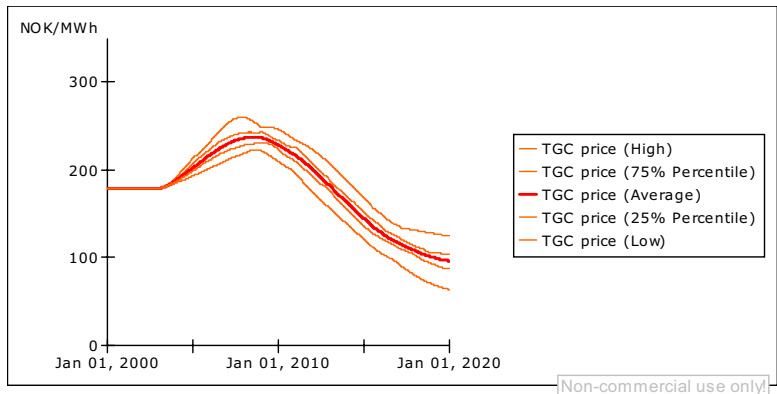
b)

c)
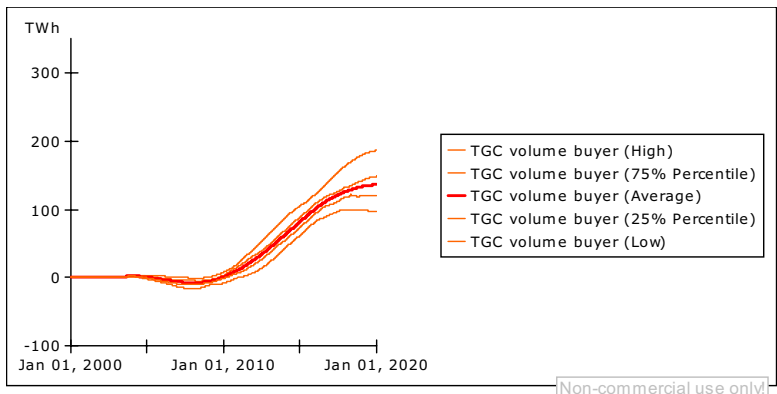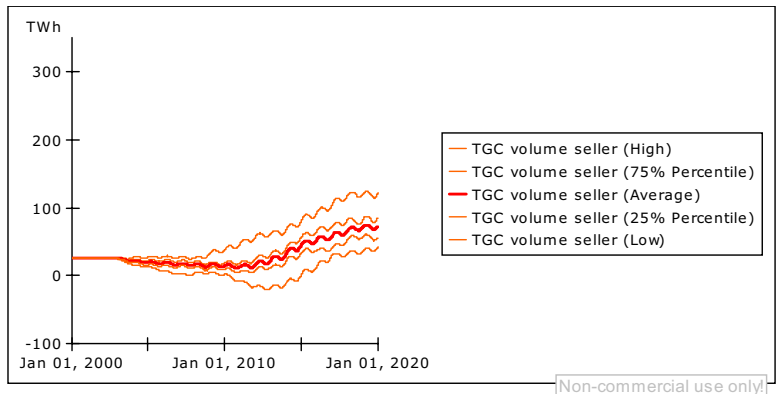
Figure 16.21 Banking 50% borrowing trend

d)
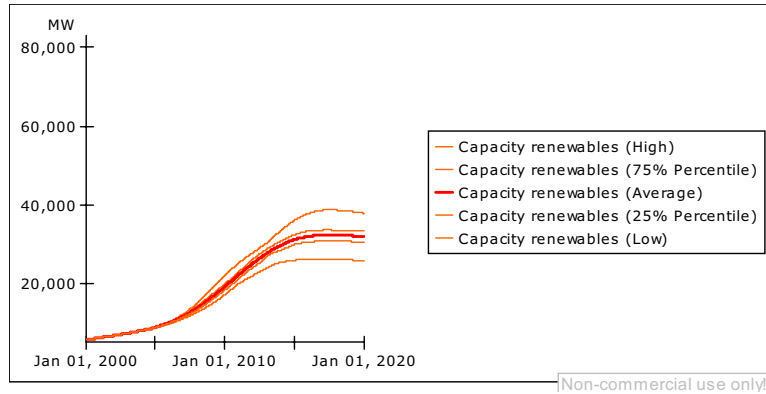
Figure 16.22 Typical simuation run infinite banking 50% borrowing with trend strategy.

a) Price
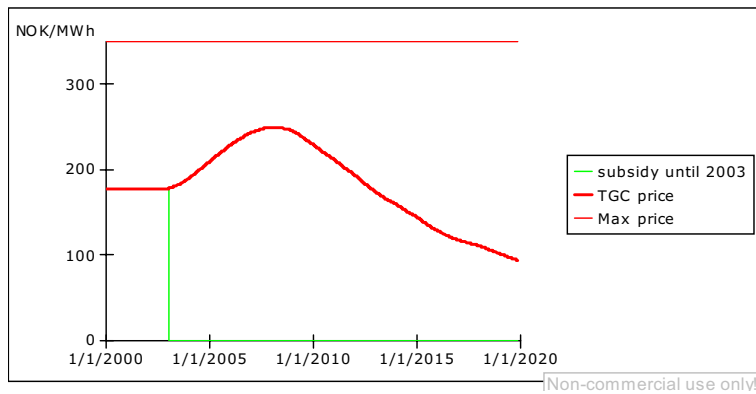
b) Effect of value and trend strategies on sales rate
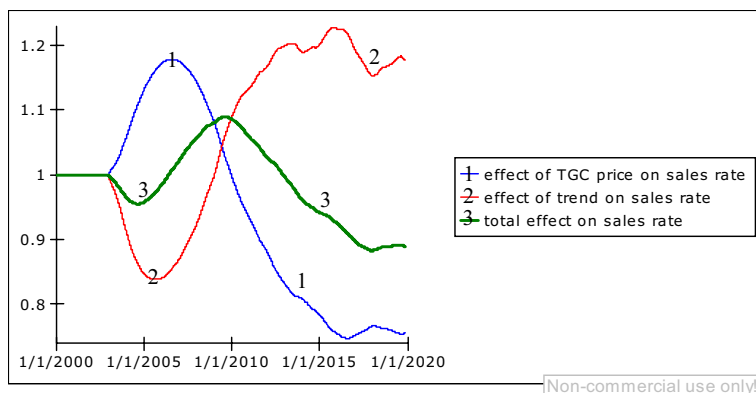
Figure 16.22Typical simuation run infinite banking 50% borrowing with trend strategy.

c) TGC volume buyer and seller.. Max borrowing limits for buyers and sellers shown as curve 3 and 4.
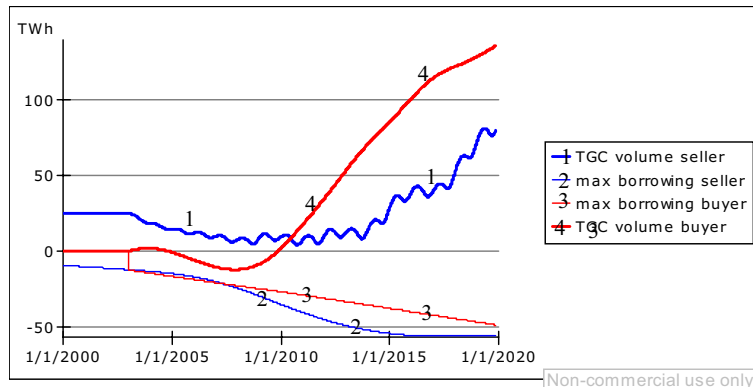
d) Capacity development
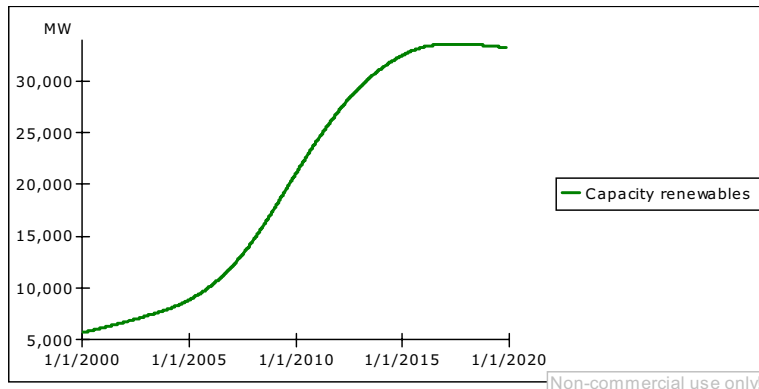
Figure 16.23No banking. 50% borrowing with trend strategy

a) Price

Figure 16.23 No banking. 50% borrowing with trend strategy

b) TGC volume buyer

```
TWh
300
200
100
0
-100
Jan 01, 2000    Jan 01, 2010    Jan 01, 2020
```

- TGC volume buyer (High)
- TGC volume buyer (75% Percentile)
- **TGC volume buyer (Average)**
- TGC volume buyer (25% Percentile)
- TGC volume buyer (Low)

Non-commercial use only!

c) TGC volume seller

```
TWh
300
200
100
0
-100
Jan 01, 2000    Jan 01, 2010    Jan 01, 2020
```

- TGC volume seller (High)
- TGC volume seller (75% Percentile)
- **TGC volume seller (Average)**
- TGC volume seller (25% Percentile)
- TGC volume seller (Low)

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d) Capacity development

```
MW
80,000
60,000
40,000
20,000
Jan 01, 2000    Jan 01, 2010    Jan 01, 2020
```

- Capacity renewables (High)
- Capacity renewables (75% Percentile)
- **Capacity renewables (Average)**
- Capacity renewables (25% Percentile)
- Capacity renewables (Low)

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cur. Laboratory experiments strongly supports the hypothesis that traders to some extent do apply trend strategies.

The problem can be avoided by allowing borrowing with or without borrowing. Banking seems to shift market power in favor of sellers whereas borrowing adjust this assymetry between buyers and sellers. These findings support the conclusions found in Schaeffer & Sonnemans (2000).

16.21 Interactions of the Spot market and the TGC market

A TGC system with mandatory demand has two partial effects on the electricity market. First it produces extra revenue for producers of renewable electricity. This will increase supply of electricity and reduce electricity demand from other sources. Secondly there will be a partial increase in the consumer price for electricity for given wholesale electricity prices since the consumer also has to buy certificates. With some price elastic demand the wholesale prices for electricity are reduced. Hence both the partial effects of the TGC system tend to reduce the income for traditional power producers. The effect on the consumer prices is however ambiguous: electricity prices net of certificates goes down but the additional costs of certificates increase the consumer price. The total impact of TGC's on consumer prices thus depend on price elasticity's of demand price elasticity of both electricity supply and TGC supply and the price on certificates. Jensen & Skytte (2001) and Bye et.al (2002) reports that for some smaller share of TGC obligations consumer prices can actually be *reduced*.

In contrast to subsidies TGC prices will influence consumers directly through the consumer price of electricity which is now both the payments from electricity generation and the TGC market. The consumer price now consist of the electricity spot price plus the fraction of renewables that must be purchased (*Eq. 16.96-16.97*). We can thus expect a reduced demand due to price elasticity of demand (see loop *B4 - TGC demand balance* in *Figure 16.24*). A reduced demand will also reduce spot prices (loop *B0 - Demand balance Figure 16.24*). This means reduced generation from thermal units because thermal generation is sensitive to spot prices (loop B1 - Generation scheduling). In the long term capacity acquisition will also be influenced by sustained lower spot prices through loop B2 - Capacity acquisition thermal and loop B3 - Capacity acquisition renewables. However investment in renewables are stimulated by B7 - capacity acquisition from TGC price which more than compensates for the reduced spot price. Finally a more subtle interaction is discovered through loop R1 in *Figure 16.24*. Investments in renewables increase total generation which reduce the spot price. However a reduction in spot price stimulates demand which also means an increase in the TGC demand leading to a higher TGC price and therefore increased profitability of renewables and investment in new capacity which increase generation and so forth. The importance of this reinforcing loop is not yet examined. A detailed feedback dominance loop analysis could reveal the relative importance of these previously mentioned loops using the proposed method of David Ford (Ford 1999). The TGC market and the electricity market interacts

through the consumer price. The subsidy scheme is now replaced by the TGC price (see eq Eq. 16.26)

Figure 16.24Causal loop diagram showing the loops between the interacting spot market and the TGC market.

a)
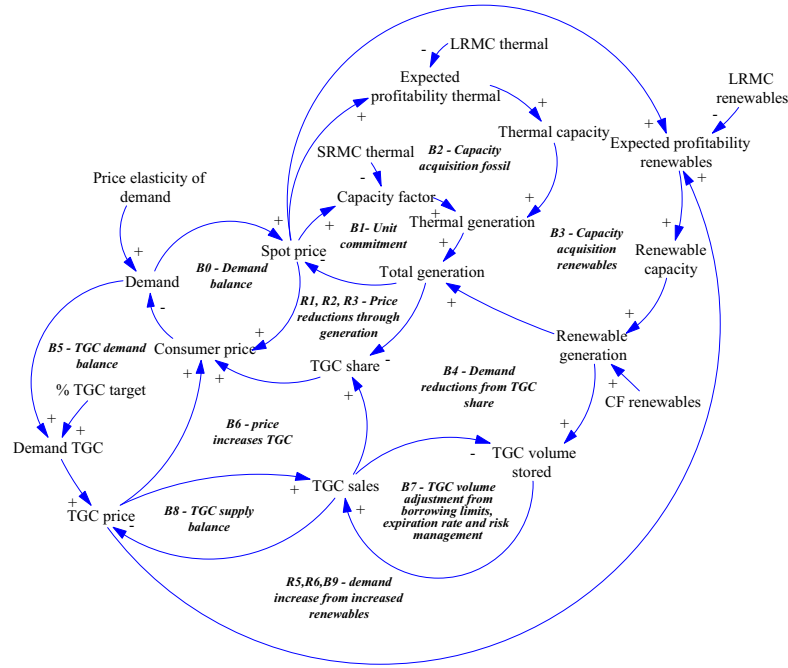
Demand side including a TGC obligation (replaces equation set 4)

16.95 *demand = Demand ref·(consumer price/Reference price)$^{Price\ elasticity\ of\ demand}$* *[TWh/yr]*

16.96 *consumer price = spot price + renewables share·TGC price* *[NOK/MWh]*

16.97 *renewables share = generation re/generation tot* *[1]*

16.98 *Demand ref = 420* *[TWh/yr]*

16.99 *Reference price = 200* *[NOK/MWh]*

16.100*Price elasticity of demand = -0.3* *[1]*

In the profitability assessment of renewables the support scheme of 178 NOK/MWh in subsidies (Eq. 16.26) is now replaced by the TGC price:

16.101*Support scheme = TGC price* *[NOK/MWh]*

16.22 Simulation results coupled markets

Integrating the TGC market with the electricity spot market developed in section 16.6 yields the results presented in the figures below. In *Figure 16.25* there is no borrowing while

TGC certificates have unlimited lifetime. In *Figure 16.26* 50% borrowing is allowed and certificates have unlimited lifetime. In both simulations the trend strategy is used in addition to

Figure 16.25 Banking no borrowing and trend strategy included. Price and generation shown as yearly averages

a) Consumer price electricity spot price and TGC price
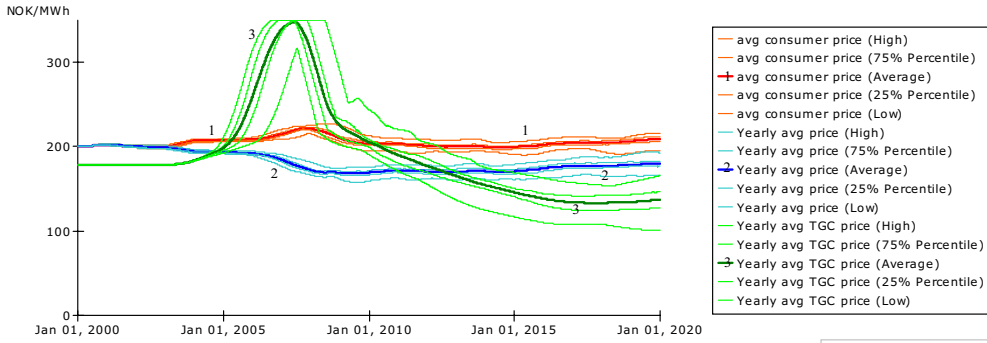
b) Total generation/demand thermal generation and renwable generation development. (Demand coincide with generation)
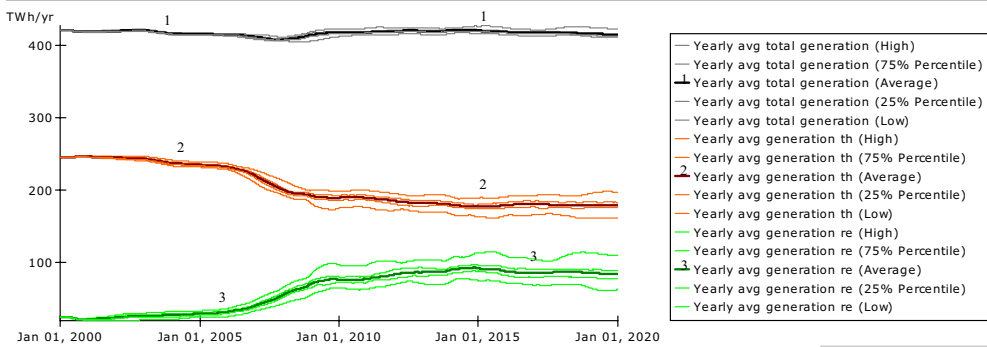
c) Capacity development
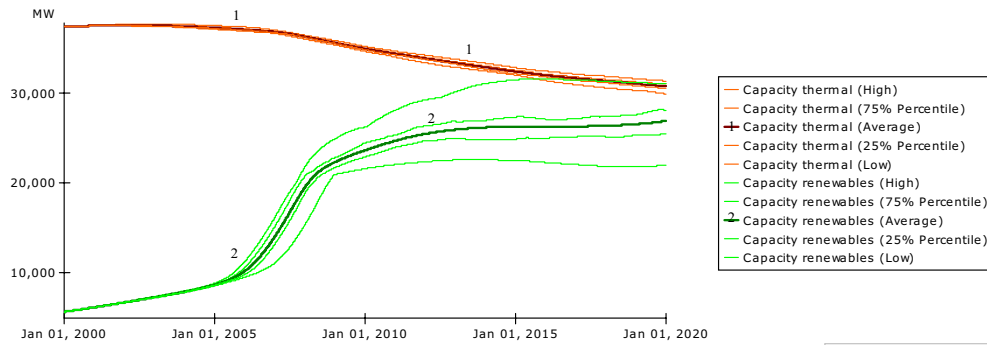
the value trading strategy.

From the preceeding discussion and in section 16.4 the results are as expected. When introducing TGCs in 2003 consumer prices increase (*16.26a*) and spot prices are lowered. *Figure 16.25b)* shows how demand and generation change under a TGC market with unlimited banking. Surprisingly the consumption remains fairly unaffected by the increasing costs from TGC obligations, because electricity spot prices are suppressed by renewable genera-

tion. The relationship between the combined income of TGC markets and electricity markets will oppose each other in cases of wet/windy years or dry/calm years. These balancing mechanisms also shown in the loop diagram in *Figure 16.24* tend to stabilise variations in revenues of renewable suppliers. During windy years the generation of wind will be high but electricity market prices decrease as will the TGC price[1]. During calm years the number of TGCs issued decreases while prices on TGC's rise and electricity prices rises as well. Developers of renewable technology may experience periods of growth and stagnation in the market for renewables which is not desirable. A properly designed TGC market can reduce the possibilities of price crashes that arise endogenously from the trading strategies examined. Allowing borrowing (*Figure 16.26*) reduces the market power of suppliers in situations of capacity deficit. A higher and smoother development of renewables can be attained by allowing borrowing of TGC's.

These simulations are based on realistic marginal operational costs long-run marginal costs and price elasticity's. Consumer prices did not reduce as a consequence of the TGC market (see Jensen & Skytte (2002) and Bye et al. (2002) for a discussion). However consumer prices did not increase significantly either but remain fairly unchanged

Figure 16.26Banking 50% borrowing and with trend strategy . Price and generation shown as yearly averages

a) Consumer price electricity spot price and TGC price
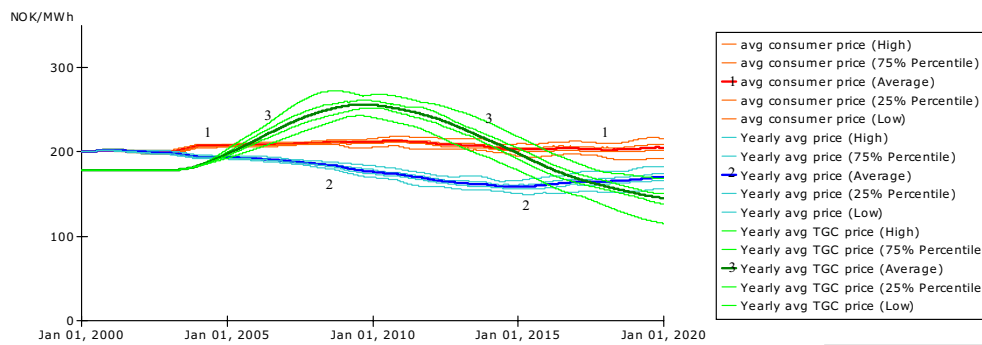
b) Total generation/demand thermal generation and renwable generation development (Demand coincide with total generation)
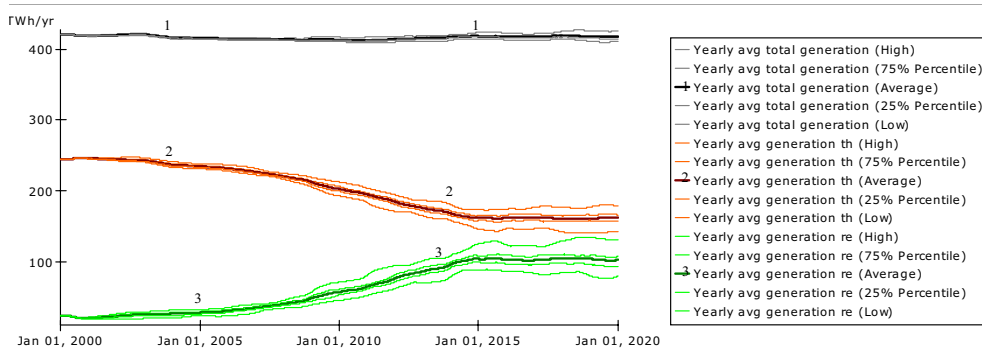
1. Of course some renewable suppliers will chose to store their certificates awaiting higher prices on TGCs

Figure 16.26Banking 50% borrowing and with trend strategy . Price and generation shown as yearly averages

c) Capacity development
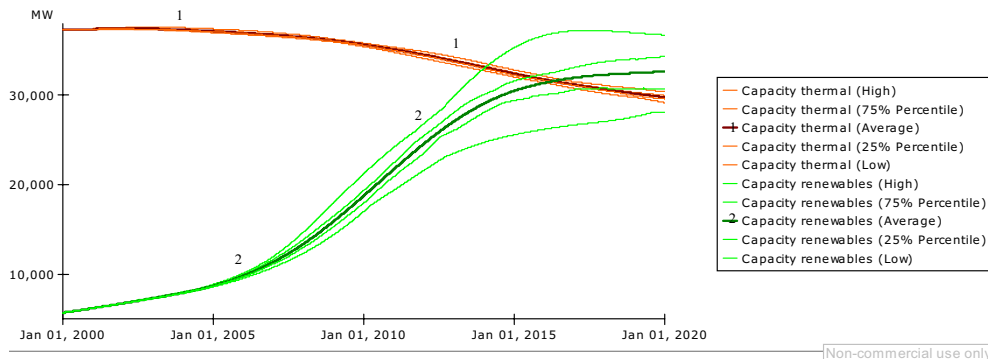
We should however note that present elctricity market prices fluctuate significantly due to daily load variations seasonal variations in demand and the stochastic properties of hydropower generation in the Nord Pool. These considerations can be taken into account by implementing the TGC market model in the more detailed Kraftsim model (see section 16.23 below)

16.23   Simulations of TGCs in the Kraftsim model

A more detailed system dynamic model of the Nordic electricity market has previously been developed (Vogstad et al 2002; Botterud et al. 2002). This model includes some additional long-term feedback loops of technology progress and resource availability. Capacity acquisition includes a more detailed description of the application process and the construction process plus the vintage structure of capacity. The profitability assessment includes a more detailed net present value calculation with feedbacks from technology progress for the investment conts and feedback from expected capacity utilisation concerning the operational costs and the expected profitability from sales of electricity. Furthermore the model distinguish between coal nuclear gas gas peak load and gas with CO2 sequestration; hydropower wind power and bio energy plus imports/exports exchange. The supply side is still kept simple with an underyling growth of demand (1.6% per year) and a price elasticity of demand with an adaptive reference price. Seasonal variations in hydropower wind energy and demand is included and a simplified water value method for hydropower scheduling is represented endogenously in the model.

By implementing the TGC market model in the previously developed Kraftsim model it is possible to assess the impact on various energy technologies and to which extent TGC markets can be used as an instrument to transit from a fossil fuelled towards a renewable power supply.

16.24   Summary of conclusions

In section 16.12 we developed a system dynamics model of the TGC market that pointed out the possible problem of price formation from the lack of short-term regulation of supply. Adjustments on the supply side of the TGC market can only be made in the long term by investing in new capacity which makes the dynamics of the market sluggish.

The main concern of price stability in previous studies have been the yearly variations of renewables which may cause large price variations from year to year. To circumvent this

problem a TGC market with banking (i.e. unlimited lifetime of certificates) has been the preffered solution. However such an arrangement opts for strategic behavior that can induce much larger long-term price variations. If traders use price trends in their trategies the reinforcing effect causes prices to crash when sellers withold their TGC's over several years before new capacity comes on line. Allowing borrowing of certificates will reduce the impact of this strategy as buyers can postpone their obligations and developers can sell TGC's that will be produced in future years.

Partial equilibrium models and standard economics presently used to analyse TGC markets do not address these potential problems concerning price stability and trading strategies. A combination of system dynamic analysis and experimental economics can analyse the impact of various such trading strategies in order to avoid costly mistakes.
In section 16.23 we simulated the TGC market fully integrated with the electricity spot market. The balancing feedback loops between these markets seem to reduce the variations in investments of renewables that was observed in TGC market model. Consumer prices were not significantly alterend after the introduction of the TGC market.

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Part IV

Utilising the complementary characteristics of renewables

When the winds of change blow, some build walls
while others build windmills

- Old Chinese proverb

17 The hydro scheduling problem with wind power

17.1 Wind and hydro as intermittent sources of energy : A comparison.

Short-term intermittency of wind

Wind power is an intermittent source of energy and some kind of additional regulation capacity is needed. In fact,it has been argued that wind power does not contribute to firm capacity and need an equivalent amount of reserve capacity to maintain the same level of security of supply. Any source of generation has however a certain probability of failure, while it is the total system's statistical probability of failure that is of relevance (Grubb 1991a). The loss of load probability (LOLP) and the associated capacity value has been used as measures when considering new capacity additions. As a rule of thumb, wind power has a capacity value equal to its capacity factor[1], which is around 0.34 for Norway assuming 3000 yearly full load hours. Alm and Tallhaug (1993) showed that wind conditions is at least good during peak load as the yearly average along the Norwegian coast but this is depends on the geographical dispersion of wind turbines. Up to 30 percent of intermittent sources can probably be integrated with small or modest additional costs (Grubb 1991b). Experience from Jutland shows that as 40% of yearly electricity supply from wind can be integrated.

With the liberalised market such regulation costs is reflected in the balance market. Nielsen et al (1999) estimates that the fluctuations of wind would represent costs in the range of 1-2 øre/kWh assuming 30% prediction error over 36 hrs when purchased at the balance market. The low cost of the balance market is a special feature of the Nord Pool system due to the high flexibility (regularity) of hydropower. These costs can also be reduced with better prediction tools for wind power (reference to Giebel Landmark). Some experiences from Eltra here on their operations the recent years. Thus on the shorter time scale hydropower with high degree of regularity is beneficial for the integration of wind power.

Long-term intermittency

From the above discussion, we concluded that hydropower is beneficial to compensate for the short-term fluctuations caused by wind power reflected in the low costs on the balance market. If we however look at the long-term fluctuations of wind and hydro - wind turn out to vary less, within the season - and from year to year. While hydropower can vary as much as +/- 40% from year to year wind power varies by +/- 20% and correlates well with demand on a seasonal basis (Tande and Vogstad 1999). We will refer to this as the *complementaries* of wind and hydro defined as the statistical negative correlation between wind and hydro inflow on a seasonal and a yearly basis.

Previous studies using the EMPS model indicated that there are some potential system benefits that can be obtained from the complementaries of wind and hydro. In paper 1, the estimated energy value of wind power was 7 % higher than the average spot price. In paper 2 wind power increased the profits per unit of wind power was at up to 9% higher than market value (defined by the spot price).

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1. Capacity factor here defined as $\dfrac{\text{Average yearly capacity utilisation}}{\text{Installed capacity}}$

According to Tande and Vogstad (1999) (see Appendix F), wind and hydro possess complementary seasonal statistical properties as wind is highly correlated with demand while hydro is negatively correlated with demand.

In order to utilise the potential complementaries of wind and hydro the information about these complementaries must somehow be included in the *production scheduling models* and/or in the *market information* to the market participants. This will be the main subject of this chapter.

17.2 The complementary value of wind and hydro

The value of the complementaries of wind and hydro can be formulated as an initial hypothesis:

Consider a local power system as shown in *Figure 17.1* and the statistical properties of inflows as described in Tande and Vogstad (1999) and Vogstad (2000). With the negative correlation between wind and hydro, the net variation of these resources is reduced, which makes it possible to reduce hydro spillage by lowering the reservoir level without increased risk of running empty.

The potential effect of reducing spillage of course depends on the regularity of the hydropower system and its demand obligations and market access etc. Utilities perform production scheduling using the EOPS and the EMPS model in order to make the optimal production plan.

To analyse the system benefits of including wind power in hydro scheduling we will therefore develop a simplified model of hydro scheduling that sufficiently captures the features considered to be of importance. These are the stochastic properties of wind and hydro the water value method of hydro scheduling and the stochastic properties of prices. These features are already present in the Vansimtap model (EOPS) but to keep complete control over the assumptions - and the flexibility of adapting the model to the research needs - a simplified model with the essential features of the Vansimtap (EOPS) model was developed.

After developing this model, an exploratory set of simulations is performed for characteristic wind-hydro systems with various degrees of *regularity market access* and *demand obligations*. Introducing an increasing amount of wind in the simulations it is then possible to identify how the optimal production schedules change along with the associated implications for reservoir levels spillages purchase/sales and changes of profitability resulting from wind energy.

Finally, the price model is replaced by a supply curve representing thermal units to give a simplified representation of the total area with wind thermal units and hydropower in the attempt of quantifying the system benefits for the market as a whole.

Figure 17.1 Hydropower scheduling problem

a)
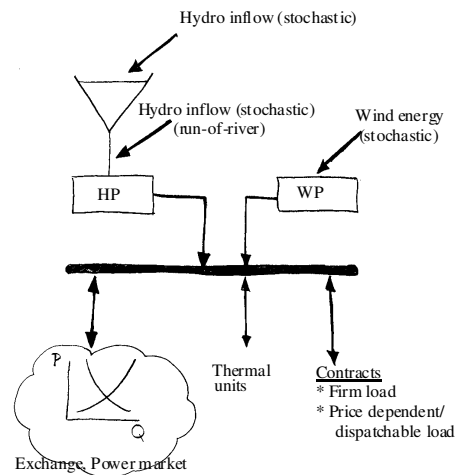
17.3 The hydro scheduling problem

Consider an aggregated representation of an area with market access. We assume the utility to be a price taker so that the spot price can be taken as exogenously given. While this assumption can be well justified in most Nordic areas this assumption is usually not the case in other electricity markets.

Figure 17.1 shows the general problem with a hydropower unit one reservoir wind power and access to market. There is also a local demand within the area[1]. Hydro inflow and wind are both stochastic variables while spot price is represented as a state variable. Demand is deterministic.

The purpose is to analyse the operational implications of wind power on hydro scheduling. The major aspects needed to take into considerations are then the hydropower unit describing its reservoir capacity and generation capacity; the access to the market and the market price and possibly demand obligations. The stochasticity of hydro inflow and wind particularly their complementaries is the focus in this analysis. We assume no thermal generation within the area. Using the EMPS model as input source for price scenarios, the prices include impacts of thermal generation in the Nordic system as well. This line of reasoning also holds for the inclusion of demand but for general purposes, we will include demand in our model setup.

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1. In the Nordic liberalised market there is no obligation to serve local loads. Inclusion of demand here is included for the purpose of generality of the model. In the case of a fully liberalised market demand obligations are set to zero.

The problem is to find the optimal production schedule over the year by controlling the production q_t for each period. We apply *stochastic dynamic programming* (SDP) to solve this optimisation problem.

17.4 Hydro scheduling as a stochastic dynamic optimisation problem

Figure 17.2 illustrates the hydro scheduling problem. At each time step, we know the reservoir level content and the market price. The more we generate in the current period the less water will be available for the rest of the year. Thus, there is a dynamic trade-off between making profits now and storing water for later use. We assume the utility to be a price taker (the production decisions of the utility does not influence price significantly). Prices in the Nordic area is however strongly correlated with the total reservoir content for the Nordic system as hydropower accounts for over 50 % of total generation. Reservoir levels change slowly due to physical constraints, which are reflected in autocorrelated spot prices. To utilise this information about price formation the price is therefore modeled as a state variable using Markov chains. Transition probabilities and prices have been derived from scenarios generated by the EMPS model, which include those aforementioned characteristics of prices.

Figure 17.2 Stochastic Dynamic Optimisation
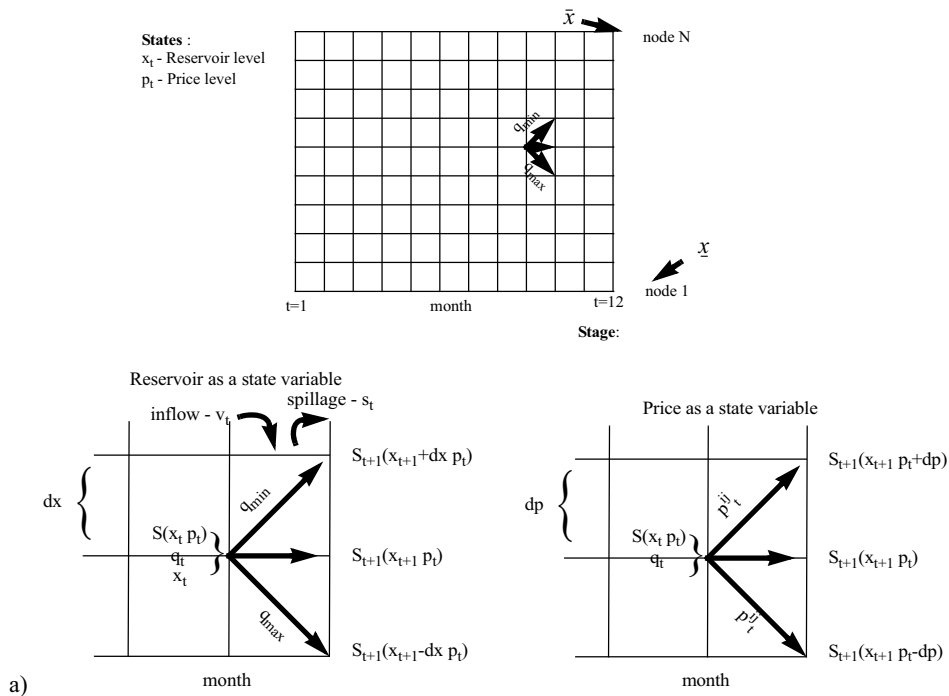
The following notations will be used:
Indexes

$t = 1 \dots T$ time period index [month]

$i, j \in \{1, \dots, I\}$ price state variable index

Sets

X - discrete feasible set of reservoir levels [GWh]

P_t - discrete feasible set of prices in period t

$Q_t(X_t)$ - the set of feasible decisions

$R = \{1, 2, \ldots 30\}$ - set of realisations of stochastic variables v_t, w_t

$S_t(x_t, p_t)$ - maximum expected future cumulative profits at state (x_t, p_t) in period t [kNOK]

State variables :

x_t - reservoir level content in period t [GWh]

p_t - electricity price in period t

Decision variables :

q_t - decision of hydro generation in period t [GWh/mo]

Stochastic variables :

v_t - hydro inflow in period t [GWh/mo]

w_t - wind energy in period t [GWh/mo]

Endogenous variables :

m_t - purchase (+) and sales (-) in spot market in period t [GWh/mo]

$s_{v,t}$ - water spillage in market in period t [GWh/mo]

$s_{w,t}$ - wind spillage in market in period t [GWh/mo]

e_t - energy deficit in case of demand obligations [GWh/mo]

Exogenous parameters

c_r - rationing cost [NOK/MWh]

d_t - demand in period t [GWh/mo]

$\underline{q}, \bar{q}$ - lower and upper constrains on generation [GWh/mo]

$\underline{x}, \bar{x}$ - lower and upper constraints on reservoir level [GWh]

$\underline{m}, \bar{m}$ - lower and upper constrains to market [GWh/mo]

$x_t \in \Omega_x, p_t \in \Omega_p$

We want to maximise expected profits over our time horizon :

$$S_1(x_1, p_1) = max_{q_k} E_{v, w, p}\left[\sum_{t=1}^{T} p_t(d_t - e_t) - p_t m_t - c_r e_t + S_T(x_T, p_T) \right] \qquad (i)$$

Using Bellman's principle, we reformulate the profit function to :

$$S_t(x_t, p_t) = max_{q_t} E_{v_t, w_t}\{p_t(d_t - e_t) - p_t m_t - c_r e_t + E_{p_{t+1}|p_t}[S_{t+1}(x_{t+1}, p_{t+1})]\} \qquad (ii)$$

subject to :

$$x_{t+1} = x_t + v_t - q_t - s_{v,t} \qquad \forall t \qquad (iii)$$

$$q_t + w_t + m_t - s_{w,t} = d_t - e_t \qquad \forall t \qquad (iv)$$

$$\underline{q} \le q_t \le \bar{q} \quad \forall t \tag{v}$$

$$\underline{x} \le x_t \le \bar{x} \quad \forall t \tag{vi}$$

$$\underline{m} \le m_t \le \bar{m} \quad \forall t \tag{vii}$$

$$s_{v,t}, s_{w,t} \ge 0 \quad \forall t \tag{viii}$$

Equation Eq. (ii) yields the cumulative expected profits for each state (x_t, p_t) for each period t. The first term represents profits from *purchase/sales in the spot market* and local demand obligations if any. $E_{p_{t+1}|p_t}[\ \bullet\ ]$ term represents the conditional expected cumulative profits for the subsequent period $t+1$. The derivation of the price $p_{t+1}|p_t$ will be explained in details in section 17.6. By discretisation of x_t p_t and t we build a three-dimensional table of $S_t(x_t, p_t)$ by applying stochastic dynamic optimisation for each state.

Equation Eq. (iii) represents the change in reservoir level (water mass balance). Equation Eq. (iv) represents the energy balance and Eq. (v)...Eq. (vii) is upper and lower *generation reservoir* and *market access* constraints respectively. $E_{v_t, w_t}[\ \bullet\ ]$ denotes the expectance value over the stochastic variables v_t and w_t. The representation of v_t and w_t is outlined in section 17.5.

Cumulative profits are calculated recursively backwards using stochastic dynamic programming (SDP) starting at the end period $T = 12$. Having established the cumulative profits table $S_t(x_t, p_t)$ for all x_t, p_t, t the water values can be derived as :

$$wv_t(x_t, p_t) \ = \ \frac{d}{dx_t} S_t(x_t, p_t) \approx \frac{S(x_t + \Delta x, p_t) - S(x_t, p_t)}{\Delta x} \tag{ix}$$

where Δx is the distance between two reservoir level nodes. While the EOPS model is based on the water value calculation method where water values are derived in the SDP computation - we will use the profit table directly for production scheduling. Water values are however used to calculate the end reservoir value in Section 17.7.3. Besides the water values are easier to inspect in comparison to the profits due to their relative large magnitude in comparison to their changes.

Cumulative profits and the derived water value table using eq *(ix)* are shown in *Figure 17.3.* for a fixed value of p_t.

Figure 17.3 Upper: Cumulative profits $S_t(x_t, p_t)$ calculated for all feasible x_t, p_t, t (p_t is fixed for convenience of display) Lower: Corresponding *water values* $wv_t(x_t, p_t)$

a)
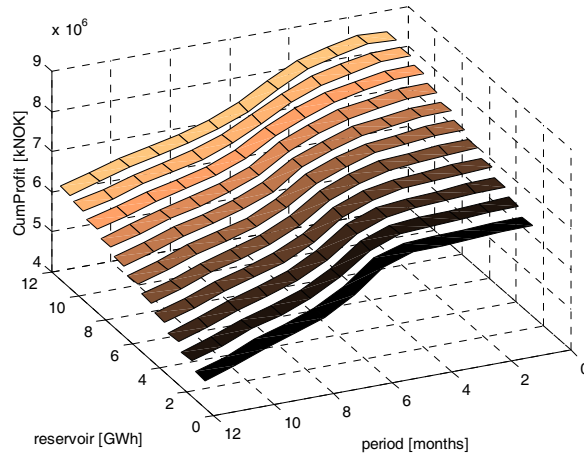
b)
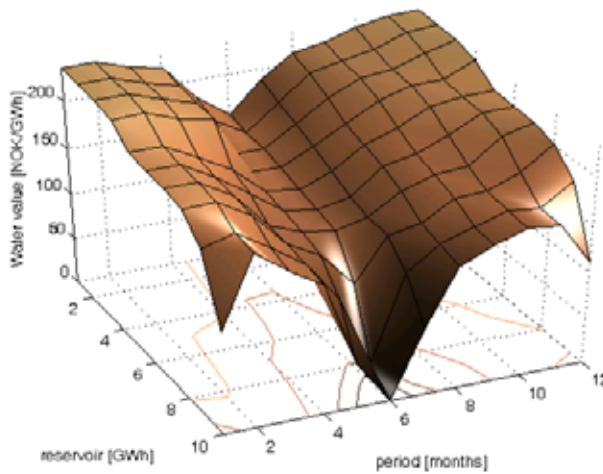
Once the profit table is established it can be used for optimising the hydropower production. Before proceeding with the production scheduling problem we will discuss the implementation of the SDP model in details. The next section deals with the representation of stochastic inflow and wind derived from historical time series. section 17.6 derives the price model used in this study and section 17.7 deals with the boundary conditions of the calculation of the profit table $S_t(x_t, p_t)$.

17.5   Data

The EMPS and Vansimtap model utilise HYDARK a database containing historical weekly inflow data over the period 1931-1990. The inflow data is used to give a stochastic representation of inflow. In addition the SINTEF-project "Integrasjon av vindkraft i det norske kraftsystemet" (Vogstad et al 2002) gathered DNMI[1] wind series from 1961-90 and converted to energy series. The conversion from wind speed into energy series is described in Tande and Vogstad (1999). We will adapt weekly inflow data for MidtNorge region during the period 1961-90 from HYDARK and corresponding weekly wind energy data from 1961-90 from Ørland located in MidtNorge.

For this principal study a time resolution of 12 months was chosen for the SDP model in order to reduce the computation time. Still the essentials of the seasonal variations are captured. However the time resolution as well as the resolution of the state variables *reservoir* and *price* can be specified by the user and does not introduce any other changes in the problem formulation.

We retrieve price scenarios from the EMPS model using our specified data set that was used in the simulation studies with EMPS in chapter xx and is consistent with the data for the system dynamic model. The EMPS model generates price scenarios to be used for utilities as input for the price model in EOPS. The data is shown in *Figure 17.4* before and after sampling. Inflow and wind series are normalised as percentages of 30-years average values.

Figure 17.4 Distributions of inflow wind and spot prices shown as 0% 25% 75% and 100% percentiles and *mean value* (middle line).   Inflow and wind from 1961-90. Spot prices are scenarios generated in EMPS. Left: weekly resolution Right: corresponding data downsampled to monthly resolution.

a)

b)

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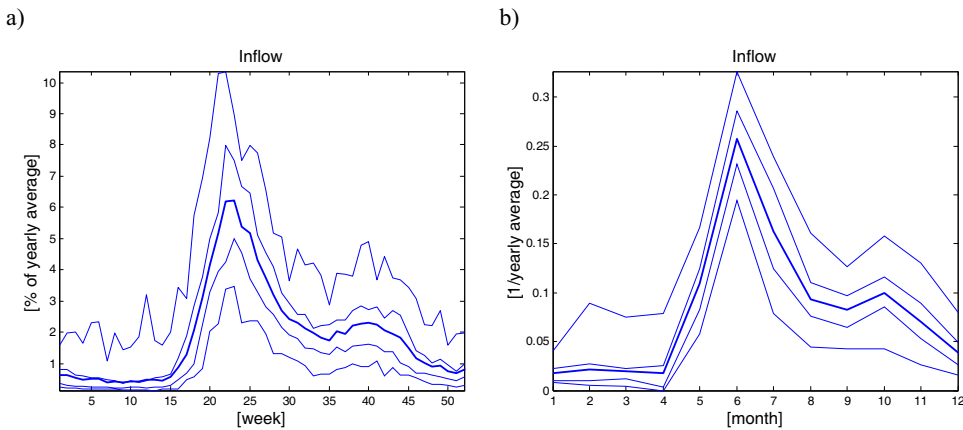
1. DNMI the Norwegian Meterological Institute

Figure 17.4 Distributions of inflow wind and spot prices shown as 0% 25% 75% and 100% percentiles and *mean value* (middle line).   Inflow and wind from 1961-90. Spot prices are scenarios generated in EMPS. Left: weekly resolution Right: corresponding data downsampled to monthly resolution.

c)

d)

e)

f)
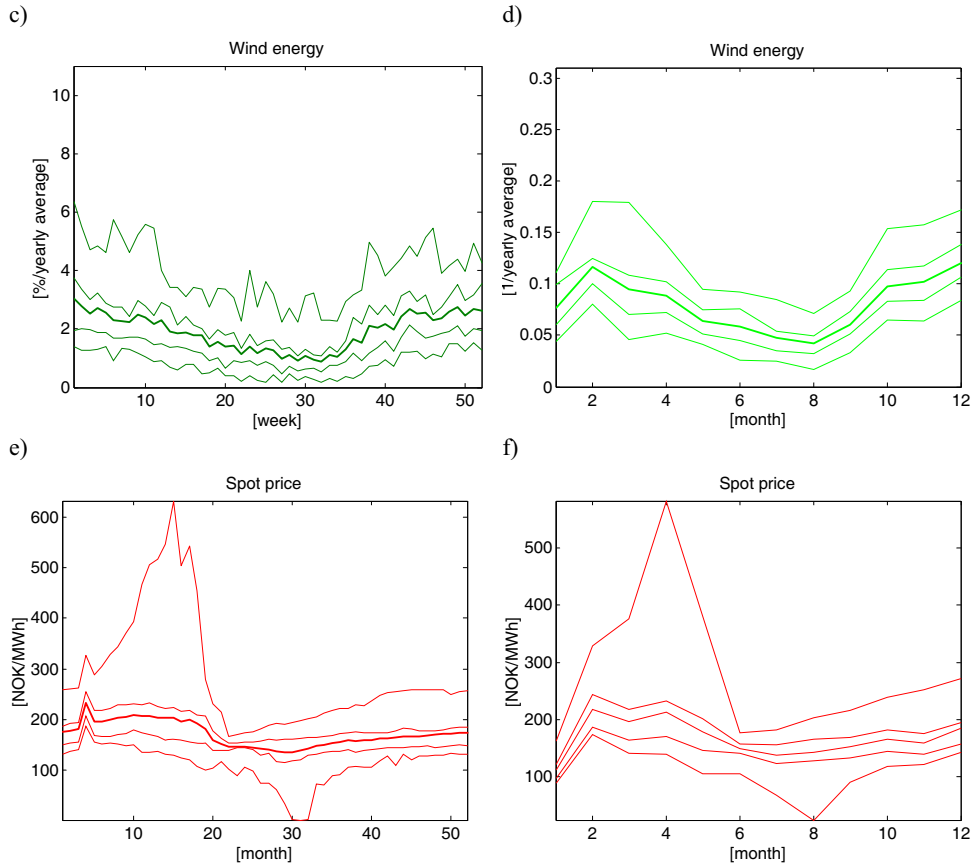
The other reduction of the original data is to convert the 30 realisations into a set of N equivalent realisations while keeping the statistic properties of the inflow and wind energy data. In the EMPS and EOPS model 60 years of data is grouped into seven weighted realisations for each week that maintain the statistical properties of the original data. An underlying assumption here is that the autocorrelation of inflow from one week to the next is insignificant. Furthermore it also requires that the cross correlation for inflow series within an area is of less importance.

In our simplified implementation of the SDP model we adopt the following approach : The historical time series are organised into histograms containing N bins and an average value for each bin. The mean value of the bins now represents the reduced set of realisations weighted by the frequency distribution. The number of samples can be specified in the mod-

el. As a special case 30 samples correspond to running all the series without grouping into histograms while a resolution of one sample provides a deterministic run of average values.

Figure 17.5 Reduction of samples. Left: Historical inflow data for August **Right:** Histogram for August with weight (frequency) along y-axis and normalised inflow (in fraction of total sample**)** along the x-axis.

a)

b)
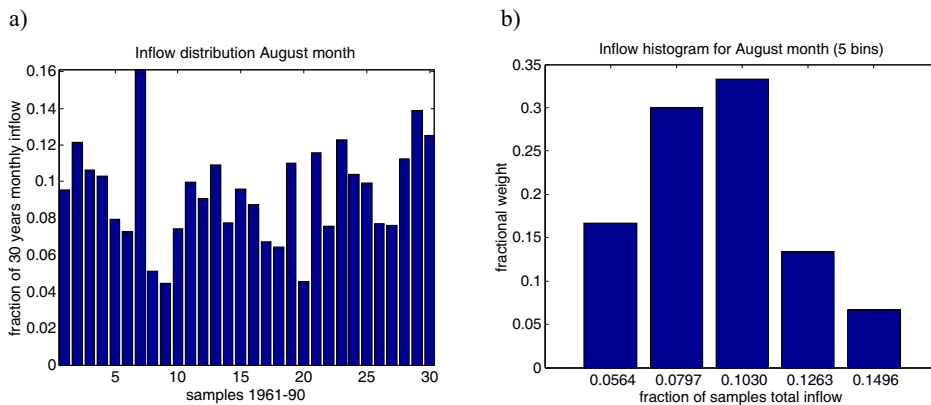
From our analysis in Tande and Vogstad (1999) we observed a weak positive correlation of 0.45 of wind and hydro from year to year. We have earlier assumed that the seasonal variation is by far the most important aspect of coordinating wind and hydro but we will also address the weak yearly correlation.

17.6   The price model

With deregulation price prognoses have become increasingly more important in production planning. In the past each unit was jointly optimised with other units of the utility. (locally). Coordination through the Association of integrated operation and later on the Natinoal Pool (see section 17.1) enabled to some extent optimisation of production nationally. Introduction of the market and the spot price have decoupled the planning problem to include the decisions of others in the price (Bjørkvoll et al. 2001). In principle and under perfect market conditions this secures optimisation of the total Nordic electricity supply as well as other economic sectors. In this model price is represented as a Markov chain as is done in the EOPS model (Mo et al. 2001) that is suited to capture the autocorrelation of prices between over time while representing a copable number of stages for the purpose of optimisation.

The Markov chain has N number of states (specified by the user) for each time step each with and transition probabilities to the states in the next period. *Figure 17.6* illustrate the Markov chain for $N = 3$ price levels while our model uses five price nodes.

Let p_t^i denote the electricity price at state i in period t and P_t^{ij} denote the transition probability from i in period t to j in period $t + 1$. Each node has the following properties :

$$\sum_{j \in I} P_t^{ij} = 1 \quad \forall i, t \tag{x}$$

$$n_{t+1}^j = \sum_{i \in I} n_t^i \cdot P_t^{ij} \quad \forall j, t \tag{xi}$$

$$0 \le P_t^{ij} \le 1 \quad \forall i, t \tag{xii}$$

Figure 17.6   Price represented as Markov chains
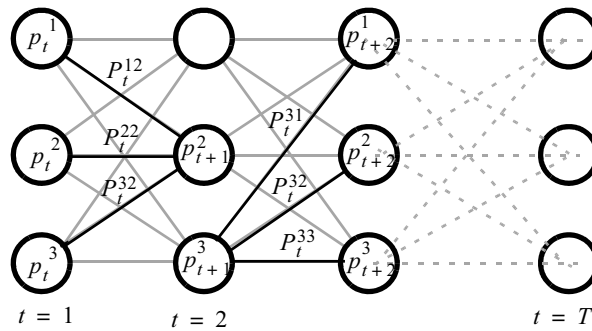
a)

Price scenarios generated by the EMPS model can now be used to estimate the transition probabilities and the prices in the Markov chain. By using price scenarios from the EMPS model the physical characteristics and interdependencies of the production system is fully taken into account. The inertia of the hydropower system and its reservoirs results in   autocorrelated prices seasonal variations of demand inflow and wind and minimum price levels (due to the operational costs of hydropower and baseload thermal units). The dataset used for our price forecast with the EMPS model is consistent with the datasets reported elsewhere in this thesis (see Appendix B).

Fitting p_t^i and P_t^{ij} to the price scenarios can be formulated as an optimisation problem. Following the approach in Mo et al. (2001) we group the price scenarios from the EMPS model into N bins for each period t corresponding to the states in the Markov chain. The average prices of the scenarios within each bin are then an estimate the price at that state. The transition probabilities from price node i to j from period t to $t+1$ can be estimated by counting the scenarios that was present in both current node i and the preceding node j. The problem then reduces to grouping the scenarios into N bins for each period t that gives a fair representation of the distribution of the original price scenarios. This can be formulated as an optimisation problem that is solved independently for each period t. The decision variables are then the bin edges b_t^i $i = 1 \ldots N+1$ from which the scenarios in each bin n_t^i is determined. Constructing the histogram the objective function may be to try to keep the bin width as equal as possible (as was done by Mo et al. 2001) alternatively to minimise the difference in areas between the bins. In statistics histograms with constant areas rather than constant bins give a better representation of the distribution of data so the latter criteria was chosen :

$$Min_{b_t^i, n_t^i} \; z \; = \; std(A_t) \qquad\qquad (xiii)$$

s/t

$$n_t^i \geq 1 \quad \forall i \qquad\qquad (xiv)$$

$$\sum_{i \in I} n_t^i \; = \; 30 \qquad\qquad (xv)$$

where A is the vector of bin areas:

$$A_t \; = \; \{A_{i,t}\} \; = \; (b_t^{i+1} - b_t^i) \cdot n_t^i \quad \forall i, t \qquad\qquad (xvi)$$

The above optimisation is performed independently for each period $t = 1 \ldots T$. The objective function expresses the standard deviation of the bin areas for each timer period as defined in Eq. Eq. (xvi). The sum of realisations in the bins across one period must equal the total number of scenarios (which in our case amounts to 30).

The problem is a nonlinear one given the discrete variable n_t^i and has been solved using a constrained evolutionary optimisation algorithm (see Runarsson and Yao (2000)).

Figure 17.7 Left: $std(A_t) = 0$ **in optimal solution** n_t^i **shown in the figure to the right**

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a)
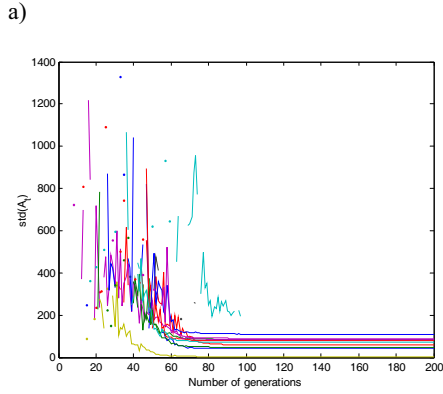
Each element in n_t^i contains a set of spot price realisations $\left\{\tilde{p}_t^{r_i}\right\}, r_i \in R_i$ (for example $n_t^4 = \{\tilde{p}_t^2, \tilde{p}_t^6, \tilde{p}_t^{11}\}$ where $R_4 = \{2, 6, 11\}$ corresponding to the realisations 2 6 and 11 of the price prognosis data). The diacritical mark $\sim$ indicate the price from the scenario data. The price p_t^i in the Markov chain can now be estimated as :

$$p_t^i = mean\left(\left\{\tilde{p}_t^{r_i}\right\}\right), r_i \in R_i \quad \forall i, t \qquad \textit{(xvii)}$$

The transition probabilities P_t^{ij} are estimated as the number of realisations present in bin i at period t *and* bin j in period $t + 1$ divided by the total number of realisations in bin j at period $t + 1$:

$$P_t^{ij} = \frac{card(n_t^i \cap n_{t+1}^j)}{card(n_{t+1}^j)} \quad \forall t, j \qquad \textit{(xviii)}$$

The estimates of P_t^{ij} and p_t^i yields a feasible solution that satisfies Eq. (xiv) and Eq. (xv) and Eq. (xx).

In addition the following properties should also be satisfied :

$$E[p_{t+1} | p_t] = \sum_{j \in I} P_t^{ij} \cdot p_{t+1}^j \quad \forall t \qquad \textit{(xix)}$$

$$E[p_t] = \frac{1}{N} \cdot \sum_i n_t^i \cdot p_t^i \quad \forall t \qquad \textit{(xx)}$$

$$n_{t+1}^j = \sum_{i \in I} P_t^{ij} \cdot n_t^i \qquad \textit{(xxi)}$$

Equation Eq. (xix) states that the conditional expected price in period $t + 1$ should equal the sum of transition probabilities departing from the known price p_t^i times the corresponding price nodes in $t + 1$. In the first period $t = 1$ the preceding period is defined as the last period in the previous year ($t = T$). The unconditional expected price (mean price for each period in the price prognosis) represented by Eq. Eq. (xx) should equal the mean prices in the Markov nodes for each period t.

Finally the condition Eq. (xxi) states that the number of scenarios of each node must equal the sum of transition probabilities from i to j times the number of scenarios in i. The construction of the price model from the price scenarios takes an engineering approach using Eq. (xix) and Eq. (xx) as criteria for the goodness of the fit - in addition practical experience of how fast observed prices should converge towards the long-term average price. For a more detailed treatment of the performance see Botterud (1999). The model outlined in this section differ in some respects. Firstly the time resolution is months (although the model can in principle run with any time resolution). Secondly the fitting procedure differ in several respects but the model and the approach is in principle the same. In *17.7* the unconditional expected spot price is compared with how two initial price situations in period 1 (p_1^1 and p_1^5) converge towards the average price. The right in *17.7* the prices of the Markov chain is shown (compare with *17.3*).

Figure 17.8 Left: Convergence of Markov prices towards average prices from two initial prices p_1^1 and p_1^5 .
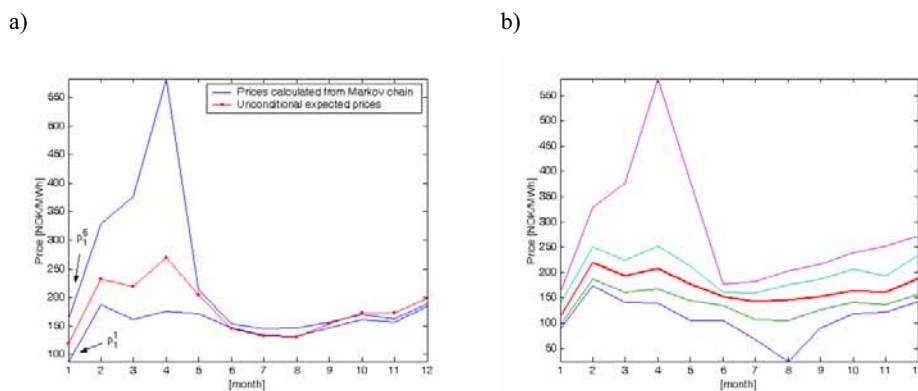
17.7 Boundary conditions in the water value calculations

17.7.1 Spillage

When the reservoir level is full and the inflow rate exceeds generation capacity the value of storing one additional unit of water is zero. If the reservoir level is full but the inflow rate is lower than the generation capacity water values equals the change in expected future profits. These situations are special cases of the calculation procedure for the profit table and no changes need to be done.

Figure 17.9 Water value isocurves in [NOK/MWh] (p_t is fixed). Water values approaches 0 at the upper reservoir level while reaching the market price or rationing costs at the lower level. End reservoir values are determined by an iterative procedure.

a)
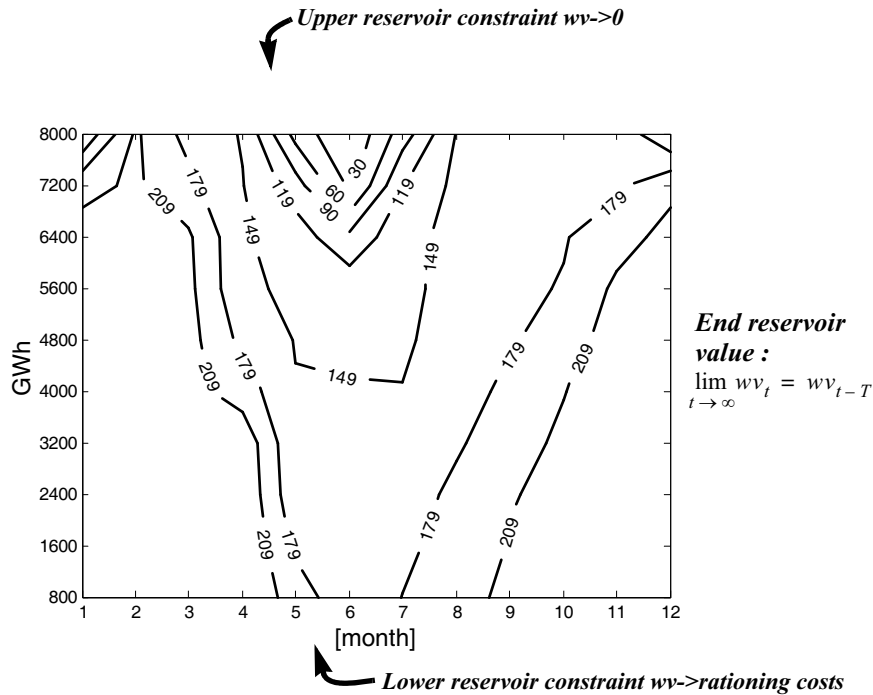
17.7.2 Rationing costs

When the reservoir levels are low the risk of energy deficit increases if there is other constraints on market access or demand obligations. Under the old regime rationing costs had to be paid to the customer if the utility failed in fulfilling its obligations. The rationing costs are set to reflect the costs of energy deficits[1]. Under the liberalised market utilities have no obligation to serve local loads. The extremely dry Autumn in 2003 caused high prices throughout the winter. Though the Winter 2003 has been referred to as an energy crisis the situation of rationing was avoided while spot prices increased above 1000 NOK/MWh for several weeks. If a utility runs empty the price in the area is likely to be very high and we can regard the rationing cost as a "lost income" or as an economic penalty of running empty when the prices are high.

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1. Contingent ranking methods can be used to estimate value of loss of load from a consumer utility perspective see Willis and Garrod (1997).

In the SDP calculation there energy deficits are likely to occur at some stages in the extreme scenarios. The profit function and the energy balance equation (Eq. (iv) and Eq. (ii)) is modified as follows :

$$q_t + w_t + m_t = d_t - e_t \quad \forall t \qquad (xxii)$$

where e_t represent energy deficit in period t. The profit function (first term in equation Eq. (ii)) is then modified to

$p_t((d_t - e_t) - m_t) + c_r e_t$ where c_r is the rationing costs. For our case study the rationing cost is set to 2000 NOK/MWh on non-delivered power. This might be too low as the observed market prices last year exceeded 1000 NOK/MWh for several weeks without any situations of blackout.

17.7.3 Estimating the value of the reservoir at the end of the planning period

To be able to compute Bellman's equation recursively (Eq. (ii)) the reservoir value at the end of the planning period must be known. The common practice for hydro scheduling is to adopt an iterative procedure in which the water values for the end period is used as the water value for the first period in the next iteration. This procedure is repeated until the end water values in two subsequent iterations have converged.
In mathematical terms :

$$\lim_{t \to \infty} wv_t(\boldsymbol{x}_t, \boldsymbol{p}_t) = wv_{t-T}(\boldsymbol{x}_t, \boldsymbol{p}_t) \qquad (xxiii)$$

where $T = 12$ months is the planning horizon.

Figure 17.10 shows columns of cumulative profits for each reservoir state. The corresponding water values are shown in *Figure 17.10*.   After a few years of iterations the end

Figure 17.10Upper graph: $S_t(x_t, p_t)$ **Lower graph: Water values** $wv_t(x_t, p_t)$ **computed for four consecutive years. (Price state is fixed)**

a)
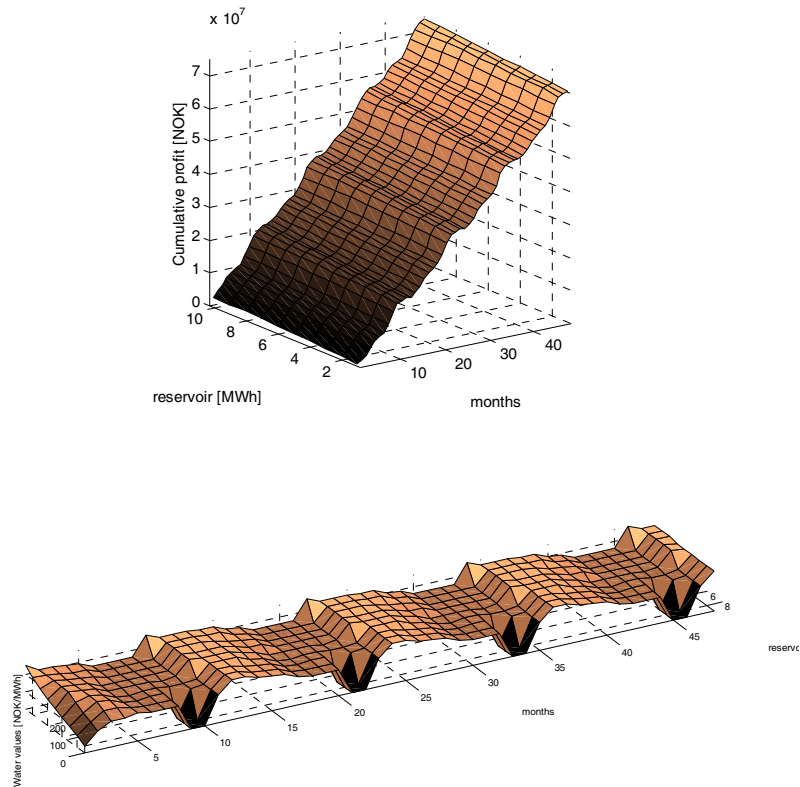
water values converge

Figure 17.11Water value columns for each end period calculated for two consecutive years. The first water value is the assumed initial water value. The next column is the computed end water value, which is then used as the first month's water value in the third iteration. End water values converge after two iterations in this example.

a)
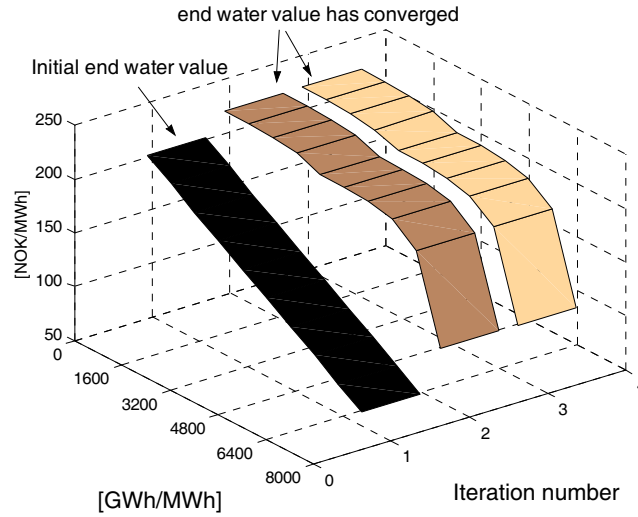
17.8   Hydro scheduling using water values

The purpose of the water value table was to calculate optimal production schedule. Stored water now has a value (comparable to that of fuel prices for thermal units) that can be used for optimal production scheduling.

The production scheduling problem is now as follows:

$$S_t(x_t, p_t) \ = \ max_{q_t} E_{\mathbf{v}_t, \mathbf{w}_t} \{ p_t(d_t - e_t) - p_t m_t + c_r e_t + E_{p_{t+1}|p_t}[S_{t+1}(x_{t+1}, p_{t+1})] \} \tag{xxiv}$$

s/t

$$x_{t+1} \ = \ x_t + \mathbf{v}_t - q_t - s_{v,t} \quad \forall t \tag{xxv}$$

$$q_t + \mathbf{w}_t + m_t - s_{w,t} \ = \ d_t - e_t \quad \forall t \tag{xxvi}$$

$$\underline{q} \le q_t \le \bar{q} \quad \forall t \tag{xxvii}$$

$$\underline{x} \le x_t \le \bar{x} \quad \forall t \tag{xxviii}$$

$$\underline{m} \le m_t \le \bar{m} \quad \forall t \tag{xxix}$$

$$\underline{m} \le m_t \le \bar{m} \quad \forall t \tag{xxx}$$

$$s_{v,t}, s_{w,t} \geq 0 \qquad \forall t \qquad\qquad\qquad\qquad\qquad\qquad\qquad (xxxi)$$

Where $S_t(x_t, p_t)$ represents a look-up table that interpolates[1] the future expected profits previously derived from the SDP water value calculation.

This optimisation problem resembles the one for water value calculation except now we do know the water values for each state of reservoir level and period. The constraints are the same and the water value table is used as a look-up table where values are interpolated. Notably the optimisation can now be performed for each sequential time step and is thus purely a linear optimisation problem. Scenario data (hydro inflow v_k and w_k are however run without sampling (30 x 12).

Figure 17.12 Output results from hydro scheduling. In clockwise direction starting from upper left: Reservoir curves (percentiles); generation market purchase and spillage; market spot price: and stochastic inflow wind and deterministic demand.

a)

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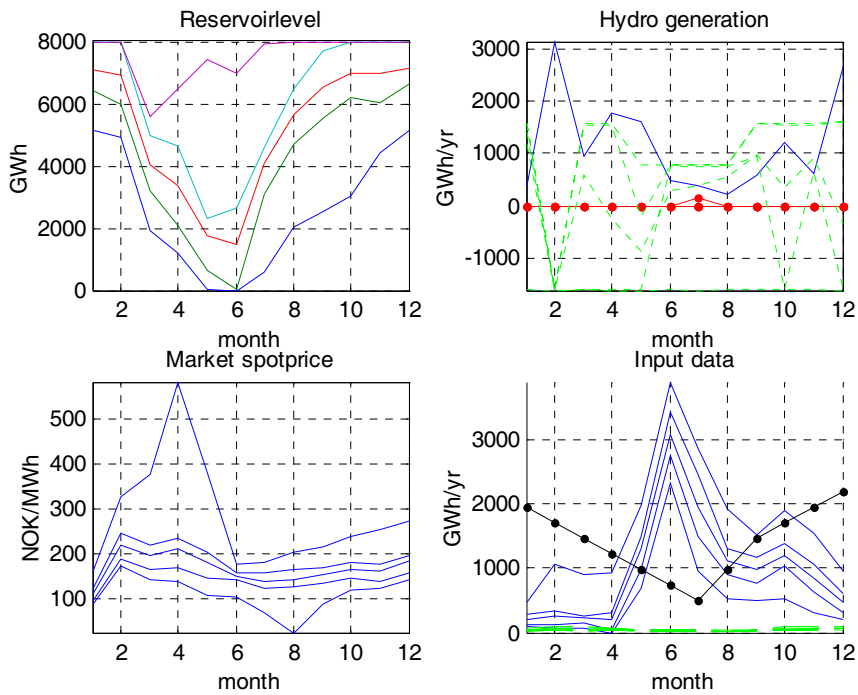
1. Spline interpolation is here used to secure a smooth surface of the optimisation algorithm. The surface is convex for variable reservoir levels x_t. And the optimisation can be performed either by linearisation and branch & bound using LP or a gradient search method.

17.9 Implementation of the SDP algorithm

Figure 17.13Calculation of cumulative profit for each possible state (reservoir level period) - (n k)

a)
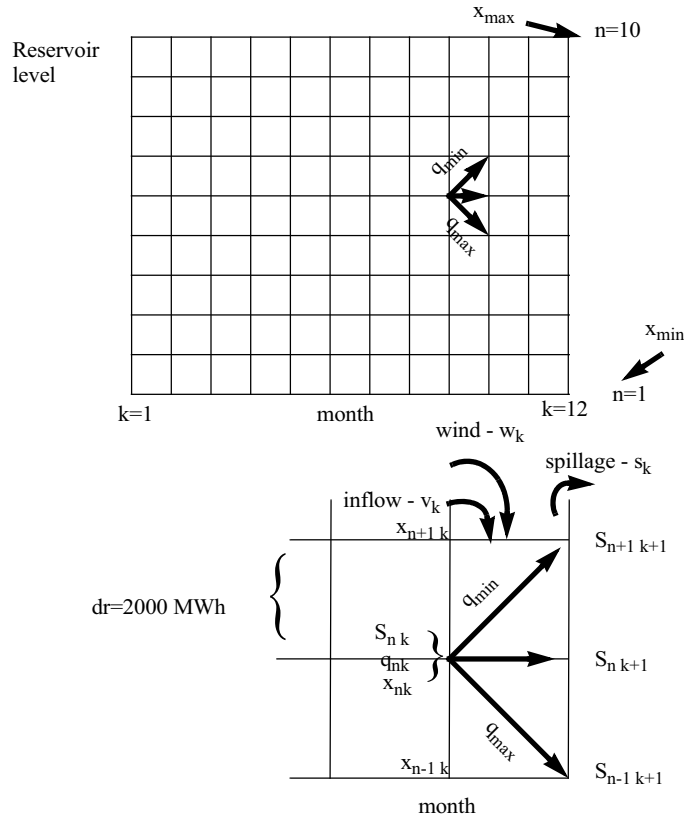
The two states comprise a grid of XxPxT nodes. At every node the maximum profits $S_t(x_t, p_t)$ is determined using backward recursion (starting from end stage $S_T(x_T, p_T)$) The optimisation

$$S_t(x_t, p_t) = max_{q_t} E_{v_t, w_t} \{ p_t(d_t - m_t) + E_{p_{t+1}|p_t}[S_{t+1}(x_{t+1}, p_{t+1})] \}$$

17.10 Representing wind in the optimisation

The following alternatives was considered to describe the complementary characteristics of wind in hydro scheduling .

Alternative I: Wind and hydro as historically correlated

This is the easiest modification, and was implemented in the EMPS model for the first time in 2000 (See Tande and Vogstad, 1999; Vogstad, 2000 and Vogstad et al, 2000 and Vogstad et al., 2001) Each historical realisation of wind energy $\{w_t\}$ corresponds to hydro inflow $\{v_t\}$. Our results from the EMPS simulation runs indicated that it is optimal to reduce the level of reservoirs, and avoid some spillage, due to the strong seasonal complementaries of wind and hydro inflow. Results from the EMPS model runs were, however not reliable for our purpose, because of the manual calibration needed for reservoir curves. To study the principal mechanisms in a controlled environment, the SDP model presented in this chapter was developed. Parameter studies seems to support our hypothesis, but so far, the discrete nature of the SDP optimisation algorithm makes the results difficult to interpret at this stage. Although the algorithm works well for hydro scheduling as shown in previous sections, it still needs to be refined in order to be used for parameter sensitivity analysis where parameters such as share of wind, reservoir capacity, market access etc. is varied incrementally.

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Alternative II: Wind and hydro as correlated

A more realistic assumption of the relationship between wind and hydro inflow, is that it is partly correlated. Implementing this into the model, requires an estimation of the correlation coefficient between each monthly distribution of inflow and wind, which can be done following the same approach as in the estimation of transition probabilities for the price model. For each time period t, apply the generated histograms for inflow and their weights. The cross correlation between wind and hydro is calculated by $\rho^{r,\,s}{}_t = \dfrac{card(w_t \cap v_t)}{card(w_t)}$ where s is the scenario index and ρ_t^{rs} is the correlation coefficient between inflow scenario r and s.

The correlation coefficients can then be included in the SDP algorithm as was done with the price model.

Alternative III: Wind as stochastic independent of inflow

Tande and Vogstad (1999) assessed the complementary characteristics of hydropower and wind energy in Norway, showing that there was a strong seasonal complementary pattern between wind and inflow, which should be beneficial for long-term scheduling. Furthermore the correlation between dry and windy years seem weaker suggesting that there is some tendency to windful years when there is wet years and vice versa. We can safely assume that there is no strong autocorrelation of wind at time scales larger than one week.

At the one extreme we can consider the relationship between wind and hydro as given by the historical time series. (This is the first implementation at present). At the other extreme we can treat wind as stochasticlally uncorrelated with hydro inflow, which makes the wind series $w_{i,\,k}$ another stochastic independent variable. With two states x_k, p_k and three stochastic independent variables v_t, w_t (inflow price wind) - where $i \in I, j \in J, l \in L$ and $I = 1...7$ $J = 1...7$ $L = 1...7$. An appropriate resolution of samples must here be defined in order to be able to solve the problem.

So far, only the first alternative has been implemented, but some more work needs to be done on the algorithm in order to be able to draw firm conclusions on the potential benefits and impacts of including wind in hydro scheduling, and is left for future work.

When the stochasticity of *wind*, *hydro inflow* and *prices prognoses* are included, we can proceed with the analysis to find the *effect of wind energy on reservoir curves (i.e. optimal production scheduling profits of including wind energy into the production scheduling tools.*

17.11 Proposed case studies

The intention of this model was twofold. First, it provides the Kraftsim model with updated water value calculations via a computer link. The system has been tested, but no detailed analysis has been performed yet about the importance of recalculating water values when major shifts in the supply curve takes place.

Second, this model allows for a principal study of integrating wind power in hydro scheduling. Some parameter studies has been carried out, however, more studies needs to be done in order to reach firm conclusions. The model works well for calculating water value tables and hydro schedules, but still needs some refinement in order to run incremental parameter studies, where reservoir constraints, hydro production capacity, share of wind power, market access etc. is varied systematically.

17.11.1 Wind power in hydro scheduling for the single utility.

The first case is with the single utility as a price taker in the market. The price model developed represent the price in the market. If access to market is not constrained by capacity, hydropower scheduling can be performed independent of wind power - even if the utility possess a lot of wind power.

In case access to market is constrained, it will be valuable to include wind power in the local hydro scheduling tools. Including wind power in the EOPS model will reflect this case. A parameter study where the SDP model calculate water values and perform one year simulation for each combination of parameters, will reveal the potential benefits of including wind power in hydro scheduling for the single utility. The parameters are the degree of regulation for the reservoirs, transmission constraints to market, and the share of hydro, wind, and local demand.

17.11.2 Wind power in hydro scheduling for the Nordic area

The second case considers the total Nordic area. If all utilities are price takers and use price prognosis as input for their local hydro scheduling tools, information about wind generation must be included in the EMPS model, which is used for price prognosis and input to the local EOPS models. The benefit for the total Nordic countries to include wind power in hydro scheduling, is taken into account by regarding Nord Pool as one area, and include the supply curve of thermal generation (i.e. the same supply curve as from the data set). Conclusions of the value of including wind power in hydro scheduling

The conference papers provided in the Appendix E reports of a series of studies using the EMPS model, where the stochasticity of wind power were included.

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Part V

Conclusions

17 Conclusions

A system dynamic model to analyse long-term versus short-term implications of various energy policies within the context of the Nordic electricity market has been developed. The model itself provides a theory of the development of the Nordic electricity market in response to various energy policies, both in the long and the short run. The model includes generation scheduling, demand, price formation, investment decisions, resource availability and to some extent endogenous technological progress. Thus, explanations of the model behaviour can be found from within the model.

The model was designed to study long term versus short-term implications of energy and environmental policies for the transition from a fossil fuelled towards a renewable electricity supply. The model however, is suited for analysing many other long-term issues of electricity markets, for instance investment cycles, reserve margins and other long-term issues.

As examples of use, the model/modelling concept addresses two important questions on the energy policy agenda. First, the marginal CO_2-emission controversy has been studied, as to whether building gas power in Norway increases or reduces Nordic CO_2-emissions.

The second study analysed the current Swedish TGC market at the time of the introduction (before June, 2003). The purpose was to assist market design. It was found that the current (as of 2003) Swedish TGC market design is likely to crash, due to the slow adjustment of the supply side, plus the possibility for banking that enable suppliers to withhold certificates and increase prices. This problem can be avoided by allowing borrowing or similar mechanisms. Furthermore, the combination of system dynamics and experimental economics was conducted and tested.

The experimental approach can play an important role in the design of market mechanisms prior to introduction to provide robust and well working markets, and the approach is now in use to evaluate alternatives for market designs in a joint Norwegian/Swedish TGC market.

Finally, a stochastic dynamic optimisation model for hydro scheduling in combination with wind power was developed. The model is based on the water value method, and contains the principal mechanisms of existing hydro scheduling models. This simplified model allows for a range of studies on how the complementaries of wind will influence the optimal hydro schedule. In particular, the hypothesis that wind power reduces the need for reservoirs has been tested, and the results show that economic benefits can be obtained by including wind in hydro scheduling..

18 Summary

A system dynamic model to analyse long-term versus short-term implications of various energy policies within the context of the Nordic electricity market has been developed. The model itself provides a theory of the development of the Nordic electricity market in response to various energy policies, both in the long and the short term. The model includes generation scheduling, demand, price formation, investment decisions, resource availability and to some extent technology progress as endogenous. Thus, explanations of the model behaviour can be found from *within* the model.

As examples of use, the model/modeling concept addresses two important questions on the energy policy agenda. First the marginal CO2-emission controversy has been study, whether building gas power in Norway increase or reduce Nordic CO2-emissions. The results were that in the short run, some emission reductions can be obtained due to substitution of existing coal units by operations of the market, but this effect was found to be modest. Existing gas power is also substituted, plus some bio.

In the long run, there are also some *investment* substitutions of renewables. These effects do not appear to be significant in the short run, but in the long run, the investment rate of renewables are reduced as a consequence of reduced prices from gas. The reduced investments in renewables results in increased emissions.

Some increase in demand is also to be expected from adding gas power, due to price elasticiy of demand. The net result is that gas power is likely to *increase* CO2-emissions, which contradicts the current belief as well as results from other electricity market models that omit the long-term mechanisms such as investment decisions and technology progress.

The second study analysed the current Swedish TGC market at the time of the introduction. The purpose was to assist market design. It was found that the current Swedish TGC market design is likely to crash, due to the slow adjustment of the supply side, plus the possibility for banking that enable suppliers to withhold certificates and increase prices. This problem can be avoided by allowing borrowing. Furthermore, the combination of system dynamics and experimental economics was conducted and tested. Combining simulation with laboratory experiments is now gaining momentum within power engineering and liberalisation of markets. The experimental approach can play an important role in the design of market mechanisms that will ensure robust and well working markets.

Finally, a stochastic dynamic optimisation model for hydro scheduling in combination with wind power was developed. The model is based on the water value method, and contains the principal mechanisms of existing hydro scheduling models. This simplified model allowed for a range of studies on how the complementaries of wind will influence the optimal hydro schedule. In particular the hypothesis that wind power reduces the need for reservoirs has been tested, and the results show that economic benefits can be obtained by including wind in hydro scheduling.

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Appendix A - Special functions

The formulation of equations throughout differs somewhat from standard mathematical notation. A common practice in system dynamics, is to use long, descriptive variable names, which becomes a problem if standard mathematical notation is used. All the equations are represented as a set of first-order integral equations using informative variable names and units. A detailed description of the format is given below. Some special functions are also applied in the model. These are defined below.

Integral equation defining levels. Time index t is used to indicate its time-dependence, while time interval $t_0...t$ of the integral is omitted. Levels always start with capital letter.

Initial levels used time index 0

Equation set heading

Rate equations are denoted with time index t and smallcase letters.

Units

The Nord Pool spot price formation

20.1 $Price_t = Price_0 + \int price\ change_t \cdot dt$ [NOK/MWh]

20.2 $Price_0 = 150$ [NOK/MWh]

20.3 $price\ change_t = Price \cdot (demand - total\ generation)/demand \cdot 1/Market\ AT$ [NOK/MW/da]

20.4 $Market\ AT = 3$ [da]

Auxiliarys are stated in smallcase letters without input arguments and time index.

When levels enter definitions, time index is omitted.

Constants start with capital letter

Equation number has the format Chapternumber.equation number

The sequence of equations is normally 1) Level equation 2) its initial value, 3) rate equation(s), 4) variables entering not previously defined entering the rate equations

20.1   GRAPH

y= GRAPH(x,x_0,dx,{y_0,y_1,...,y_n})

Graph functions interpolate between points (x,y) given by x_0, the stepsize dx and corresponding points y_0 ... y_n Linear interpolation is normally used, but steps and spline interpolation can also be performed. Values outside the range approximates to the largest or least value in the table.

Example of tabluated data:
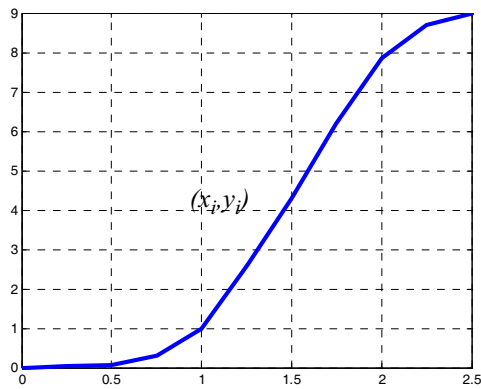
20.2   DELAYPPL(Input,Delay time)

20.1 Pipeline delay - perfect delay.

20.2 Output=DELAYPPL(Input,Delay time,<Output$_0$>)   *[Unit]*

20.3   Output$_t$=Input$_{t-Delay\ time}$

20.3   DELAYINF(Input,Delay time)

20.4 Output=DELAYINF(Input,Delay time,<Output$_0$>)

20.5   Output$_t$=Output$_0$ + $\int$change in input$_t \cdot$dt   *[Unit]*

20.6   change in input$_t$ = (Input-Output)/Delay time

20.7

20.8
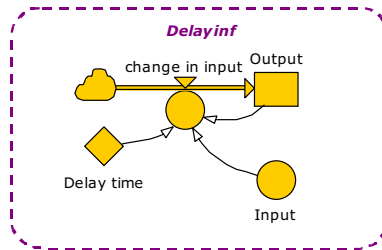
20.4   FORECAST(Input,Past time,Future time)

Forecast is a first order exponential average over Past time, used to extrapolate into Future time. *Average of Input$_0$* has the default value Input unless specified.

20.9   Output=FORECAST(Input,Past time,Future time, <Average of Input$_0$>)   *[Unit]*

20.10   Average of input$_t$ = Average of input$_0$ + $\int$change in input$_t \cdot$dt

20.11   change in input$_t$ =(Input-Average of Input)/Past time

20.12   forecast of input = Input + Input$\cdot$trend in input$\cdot$Future time

20.13   trend in input = change in input / Average of input

20.14   Output = forecast of input
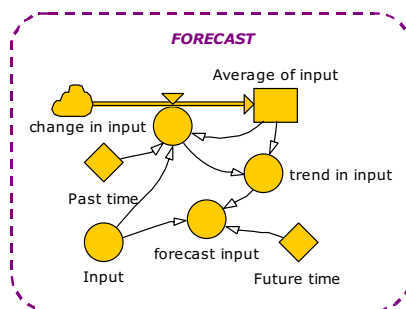
20.5 SLIDINGAVERAGE(Input,Averaging time)

20.15 Output=SLIDINGAVERAGE(Input,Averaging time,<Output$_0$>)   *[Unit]*

20.16 Level$_t$ = Level$_0$ + ∫(input$_t$-outflow$_t$)·dt

20.17 outflow$_t$ =DELAYPPL(input$_t$,Averaging time)

20.18

Appendix B - Data set

The data set here was established for the EMPS model for countrywise. installed capacity. The data refers to 1999/2000, and is used in the EMPS model, and as initial values in the Kraftsim model. A scenario for 2010 represents a future mix of installed capacity according to each country's stated targets. For more information about the data set and scenarios, see Vogstad et al. (2000).

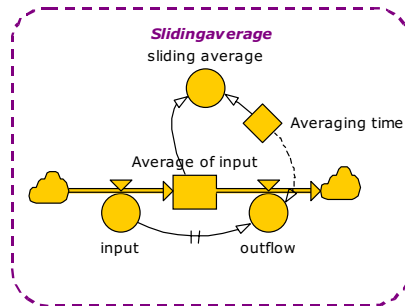|								CO2-avgift [kr/tCO2]		125
								Utslippsfaktor CO2	CO2-avgift	Produksjonskostnad inkl. CO2-avgfit
Type nr	Produksjons profil	Navn	Brensel	MW		kr/MWh	GWh målt	[tCO2/GWhel]	[kr/MWh]	kr/MWh tot
		Nord-Sverige								
20	refer	kvo Fjernvarme	olje		54	110	147	350	44	150
21	refer	kvb Fjernvarme	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			

ref2010 og vind2010

								CO2-avgift	125
							Utslippsfaktor CO2	CO2-avgift	Produksjonskostnad inkl. CO2-avgift kr/MWh tot
Typenr	Produksjonsprofil	Navn	Brensel	MW	kr/MWh	GWh målt	[tCO2/GWhel]	[kr/MWh]	
		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
						296			
		Syd-Sverige (inkl Midt-Sverige)							
20	varme	kvbo Industri	bio/olje	820	55	4500			
9	refer	kj Kjernekraft	kjernematr	8852	70	67000 (vurdert)			
32	refer	kvg Fjernvarme	ng	500	100	2500	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	1200	650	81	331
41	refer	kvb Fjernvarme	bio	1300	130	6500			
45	varme	gtgd Gassturbin	gass/dies	180	420	10	1000	125	545
		Totalt		12788		82931			
			chp-d	2486					
		Vannkraft				64000			
		Totalt				147227			

Typenr	Type	Navn	Brensel	MW	kr/MWh	GWh El	GWh varme	Utslippsfaktor CO2 [tCO2/GWhel]	CO2-avgift 125 CO2-avgift CO2-avgift [kr/MWh]	Produksjonskostnad inkl. CO2-avgfit 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			

ref2010 og vind2010

Typenr	Type	Navn	Brensel	MW	kr/MWh	GWh El	GWh varme	[tonn/GWhel]	[øre/kWh]	øre/kWh tot
		Jylland og Fyn (DANM-VEST)								
9014	vkmodul	vindkraft			prioritert	5000				
20	refer	Desentral	fornybar	660	prioritert	3300				
21	varme	Deponigass	gass	44	Prioritert	205	511	431	5.4	
22	refer	Desentral	gass	930	prioritert	4650		450	5.6	
23	varme	kvk	kull	1900		8843				227
24	varme	kvg	gass	1500		6850				263
		Subtotal		5034		28847.5	511			
		Sjælland [Danmark ØST]								
9011	vkmodul	vindkraft			prioritert	3000				
20	refer	Desentral	fornybar	600	prioritert	3000				
21	refer	Desentral	gass	200	prioritert	1000		450		
22	varme	kvk	kull	1000		4657		800	22.9	
23	varme	kvg	gass	820		4070		450	26	
		Subtotal		2620		15727	0			

Produksjon Finland   **ref1999**   CO2-avgift   125

Typenr	Type	Navn	Brensel	MW	kr/MWh	GWh målt	Utslippsfaktor CO2 [tonn/GWhel]	CO2-avgift [kr/MWh]	Inkl. CO2-avgift [kr/MWh]
		Vannkraft		2959 grunnlast		14600			
		Vindkraft		17.4 grunnlast		23.5			
		Kjernekraft							
	Frett	Import, Russland				5000			
1	varme	Olkiluoto		1680	70	6374			
2	varme	Loviisa		930	70	7600			
		Varmekraft							
4	varme	kvgb Industri	bio/NG	1550	50	10978	0	0	50
20	refer	kvk Fjernvarme	kull/olje	1447	90	5361	500	63	153
21	refer	kvg Fjernvarme	naturgass	1099	100	3638	200	25	125
22	refer	kvb Fjernvarme	torv/bark	724	170	3234	0	00	170
30	varme	kokb Kondens	kull/bark	2298	134	5965	966	121	255
31	varme	kog Kondens	naturgass	313	256	4683	595	74	331
32	varme	kob Kondens	torv/bark	1149	281	3608	0	0	281
35	varme	gto Gassturbin	olje	1450	420	20	500	63	483
		Totalt		15616		71084.5			

Tyskland   Utslippsfaktor for Tyskland er hentet fra tidligere datasett i Samkjøringsmodellen og derfor ikke beregnet her.

Type nr	Produksjonstype	Navn	Brensel	MW	kr/MWh	GWh max	GWh målt	Utslippsfaktor CO2 [tonn/GWhel]	CO2avgift	CO2avgift 125
1	varme	kvk Brunkull	brunkull	8892	65			1025	128.125	193
2	varme	kj Kjernekraft	kjerne	20223	65					
3	refer	kvk Steinkull1	Steinkull		135		66000	1025	128.125	263
4	refer	kvk Steinkull2	Steinkull		145		75000	1025	128.125	273
5	refer	kvk Steinkull3	Steinkull		155		33000	1025	128.125	283
6	varme	koo Kondens1	Olje	6640	195			692	86.5	282
7	varme	koo Kondens2	Olje	3028	315			692	86.5	402
8	varme	kog Gasskraft1	Gass	7200	250			450	56.25	306
9	varme	kog Gasskraft2	Gass	3712	200			450	56.25	256
10	kontrakt	Andre energikilder			20		2600			
30	varme	kvk Brunkull2	brunkull	6762	65			1025	128.125	193
31	varme	kj Kjernekraft2	kjerne	1590	65					
32	refer	kvk Steinkull4	Steinkull		145		20000	1025	128.125	273
33		koo Kondens3	Olje	988	245			720	90	335
34	varme	kog Gasskraft3	Gass	2678	150			450	56.25	206
35	varme	kog Gasskraft4	Gass	1071	200			450	56.25	256

Appendix C - Permit applications

Applications collected from NVE (Norway) and Skåne (Sweden)

Konsesjonær	Sted	Str MW	Forhåndsmeldi	Konsesjon søkt	Konsesjon gitt	Tid [mnd]
NTE	Hundhamn	1.5		15.12.1997	16.04.1998	4
Sandøy Vir	Sandøy	3.75		17.04.1998	23.04.1999	12
Norsk vind	Lindesnes	3.75		10.12.1998	21.03.2000	15
Miljøkraft	Tromsø	200		15.10.1999	16.02.2001	16
Miljøkraft	Havøy	40	09.11.1998	20.12.1999	24.10.2001	22
Kvalheim	Vågsøy	4.4	20.05.1998	20.12.1999	14.08.2001	20
Statkraft	Hitra	56		25.01.2000	20.12.2000	11
NTE	Nærøy	3		09.06.2000	23.01.2001	7
Statkraft	Smøla	150		18.12.2000	28.11.2002	23
Viva	Bjugn	5.75		21.02.2001	28.08.2001	6
NTE	Nærøy	45		29.10.2001	17.07.2002	9

Tillståndsprövade vindkraftverk

Kommun	Fastighet	Effekt	Antal	MW	BMP	Inkom	Kompl	Kompbe	Yttr	Beslut	Uppf	Status, övrigt	al delay for pe
Landskrona	Lundåkra 1:1	600	12	7.2						15.02.1996	Ja	Beslut konc nämnden	
Trelleborg	Maglarp m fl	600	7							18.04.1996	-		
"	"	750	7	5.25						08.10.1998	1999	Ändring av tidigare beslut	
Staffanstorp	Trolleberg 1:1	1500	1	1.5						18.06.1998	1999		
Lund	Stångby 12:5	660	2	1.32						24.06.1999	2001		
Ystad	Hedeskoga 10:2	660	2	1.32						16.12.1999	2000		
Sjöbo	Assmåsa 1:1 mfl	1500	3	4.5		24.03.1998	980828		991217	06.04.2000	2002		25
Eslöv	Kristinetorps gård	600	4	2.4		02.07.1998	980928	991103	000225	13.04.2000	2000		21
Malmö	Eldningsoljan 2	2000	1	2	991214	15.12.1999	000131	000331	000602	15.06.2000	2001		6
Kävlinge	Löddeköpinge 92:26	1500	2			23.04.1998	980520		980717	22.06.2000	-	Avslag	26
Trelleborg	Brönnestad 22:1	660	2	1.32	990622	08.11.1999	991202	000410	000714	19.10.2000	2001		11
Trelleborg	Hönsinge 17:35	660	1	0.66	990622	08.11.1999	991202	000410	000714	19.10.2000	2001		11
Svalöv	Kläsinge 1:2 m fl	1500	6	9		29.10.1998	990309	000228	000623	29.03.2001	2002		29
Eslöv,Lund	V Odarslöv 5:1	1500	6			13.05.1998	990129	991223	000505	21.06.2001	-	Avslag	37
Sjöbo	Assmåsa 1:1 mfl	1500	3	4.5	000927	13.10.2000	001106	010420	010518	30.08.2001	2002		10
Hörby	Norrto 8:2	1500	4		990622	19.08.1999	990924			26.09.2001	-	Avskrivs	25
Eslöv	Arup 1:72,Högseröd 3:3	600	2		010807	18.12.2001	020121	020125		26.02.2002		Tillbakadragen ansökan	2
Eslöv	Västraby 6:8	2000	1		010601	09.07.2001	010827			04.04.2002		Avvisat	9
Landskrona	Annelöv	1800	2	3.6	000620	20.11.2000	001214	011207	020208	04.04.2002	2002		17
Trelleborg	Näsbyholm 2:1	1800	4	7.2		07.08.1998	990323	001215	010629	18.04.2002			44
Ystad	Kärragården 5:1 m fl	850	6	5.1	991125	31.07.2001	010831	011221	020510	13.06.2002	2002		11
Lund	Stångby 12:5	750	2	1.5	010625	31.07.2001	010910	010125	020521	13.06.2002	2001	Uppgr. av Stångby ovan	11
Landskrona	Lundåkra 2:1	2000	2	4		18.12.1998	990507	020301	020524	11.07.2002	2002		43
Eslöv	Västraby 5:3	2000	3	6	010213	09.05.2001	010613	020319	020524	10.10.2002			17
Höör	Jordboen 1:1	2000	1	2	010618	19.03.2002	020409	ej begärd	020524	10.10.2002			7
Kristianstad	Köpinge 113:1, 37:18	850	5	4.25	020307	27.08.2002	020916	ej begärd	021101	14.11.2002	-		3
Ystad	Hamnen 2:2	2500	4	10		01.12.1998	990129	000426	020628	14.11.2002	-	Avslag	47
Eslöv	Västraby 6:8	2000	1	2	010601	13.05.2002	ej begärd	020523	020705	28.11.2002			6
Höör	Orup 4:2	1800	2	3.6	010806	09.04.2002	020429	020523	021101	05.12.2002			8
Kristianstad	Kiaby 8:9, Kälkestad 45:1	1300	5	6.5	010606	02.09.2002				09.12.2002		Se samma fastighet nedan	3
Svalöv	Kläsinge 1:2 m fl	1500	6	9	ej aktuellt	11.02.2002	ej begärd	ej begärd	020405	12.12.2002	2002	förl. Igångsättningstid	10
Kävlinge	Södervidinge 14:2	1500	6	9	000308	25.07.2000	000822	011207	021011	12.12.2002		Avslag	29
Eslöv	Gårdsstånga 9:1, 16:1	1800	4	7.2	011031	22.11.2001	011207	020307		12.12.2002		Avvisat	13
Ängelholm	Vegeholm 1:1	1800	4	7.2	011031	23.11.2001	011211	020307		12.12.2002		Avvisat	13

Appendix D - Sensitivity analyses

A formal sensitivity anslysis using Monte Carlo simulations are performed. In the first sensitivity analysis, all of parameters listed in *Table 1* were assigned a uniform distribution with min- and max values. The results are displayed as percentiles over the simulation period. Price, reservoir, Installed Capacity, generation and CO_2-emissions are output values. All of these variables are shown as yearly averages (except installed capacity). The first year of the simulation (2000-2001), will therefore look awkward, as there are not sufficient data to calculate average values for the first year.

The subsequent sensitivity analyses are performed by only assigning one stochastic parameter at the time.

Table 1   Parameters varied simultaneously in the sensitivity analysis.

Stochastic variable	reference value	min	max	distribution
marginal price exchange	200	.50%	+50%	uniform
Fuel price gas	90	70	150	uniform
Fuel price coal	0.4	0.2	1.2	uniform
Long term price elasticity of demand	-0.3	-0.1	-0.4	uniform
Fractional growth rate	1.5	1	2.5	uniform
Weight on LRMC in price forecast	0.25	0	1	uniform
Forward horison	4	1	5	uniform
Smoothing forward horison	3	1	7	uniform
Full load hrs wo	3500	3000	3700	uniform
Amortisation period	20	15	25	uniform
Interest rate	7	4	10	uniform
Internal rate of return	15	7	20	uniform
Learning index	[0,0.1,0.2,0.2]	-40%	+40%	uniform
Available resources	[240,175,150]	-50%	+50%	uniform
Construction time	[7,5,3,5,1,1,1.5]	-30%	+50%	uniform

Figure 23.1 Price
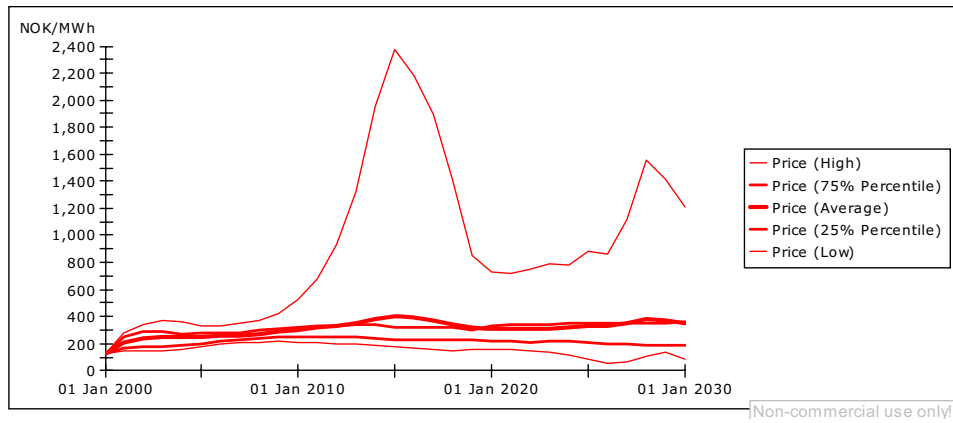
Figure 23.2 Yearly average reservoir level
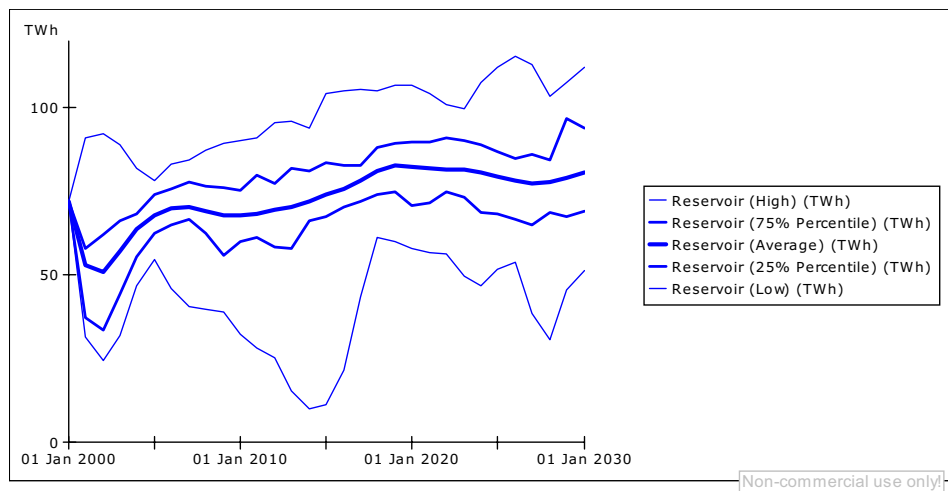
Figure 23.3 Installed Capacity
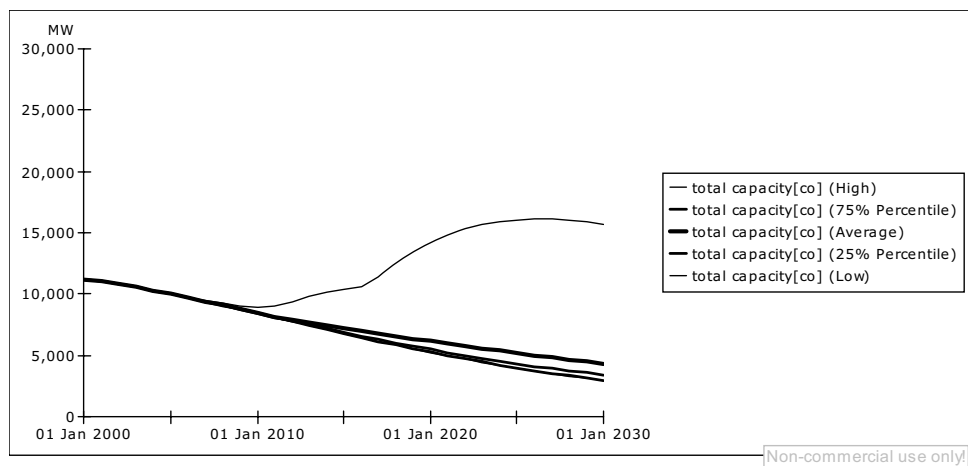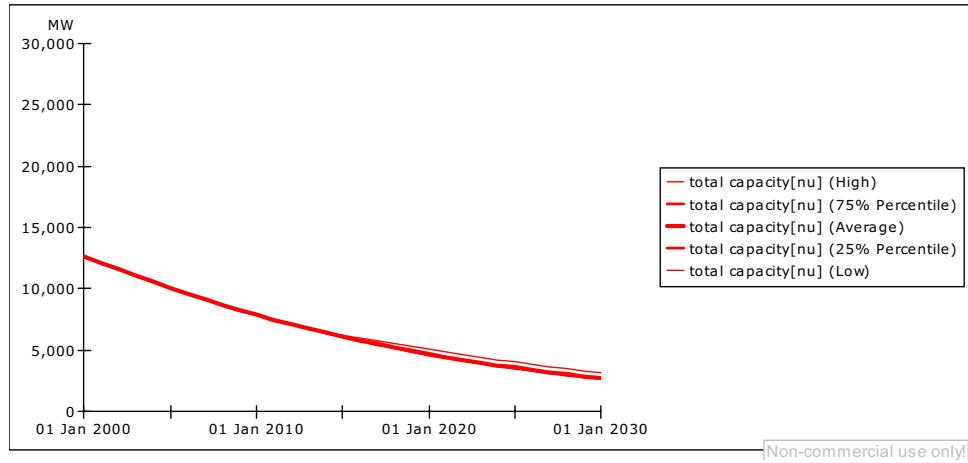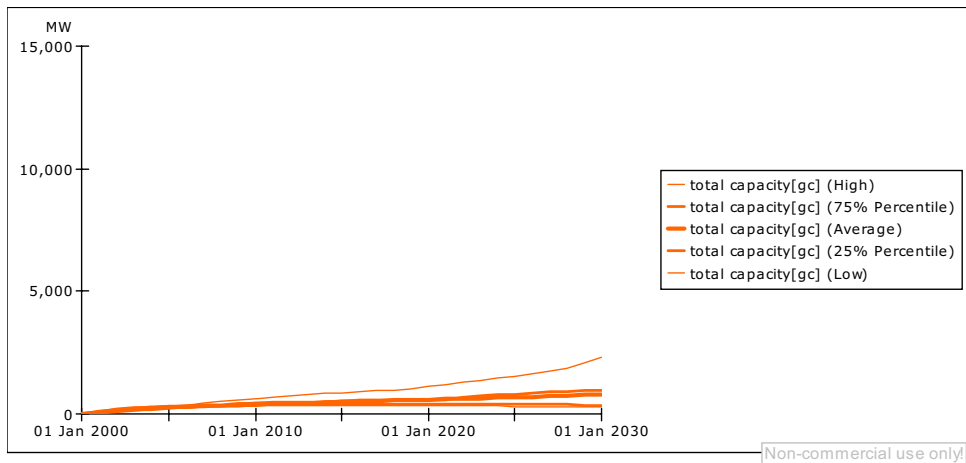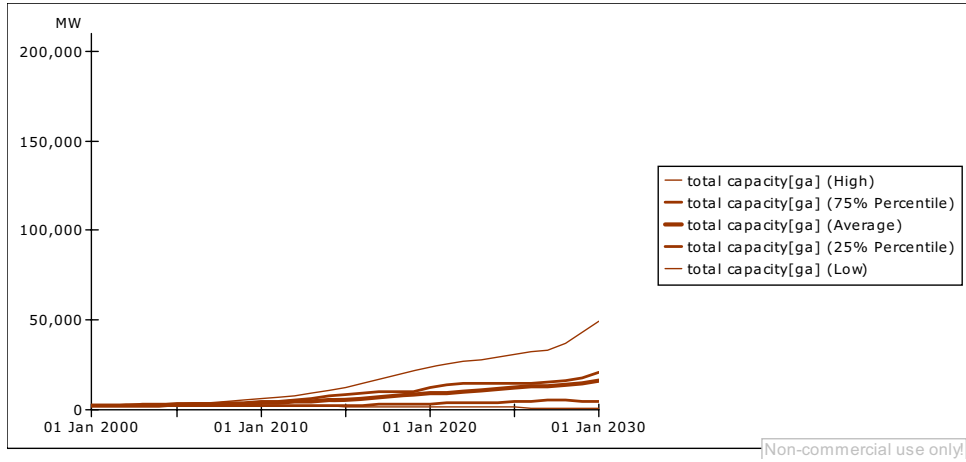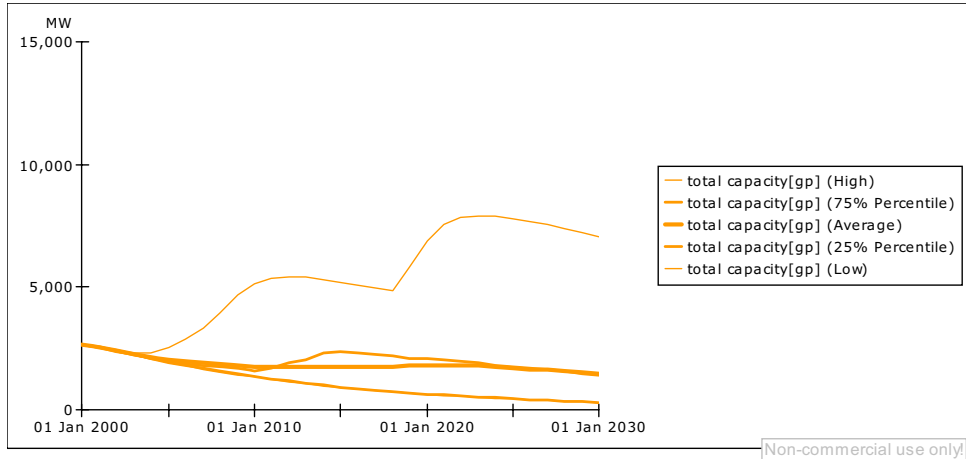
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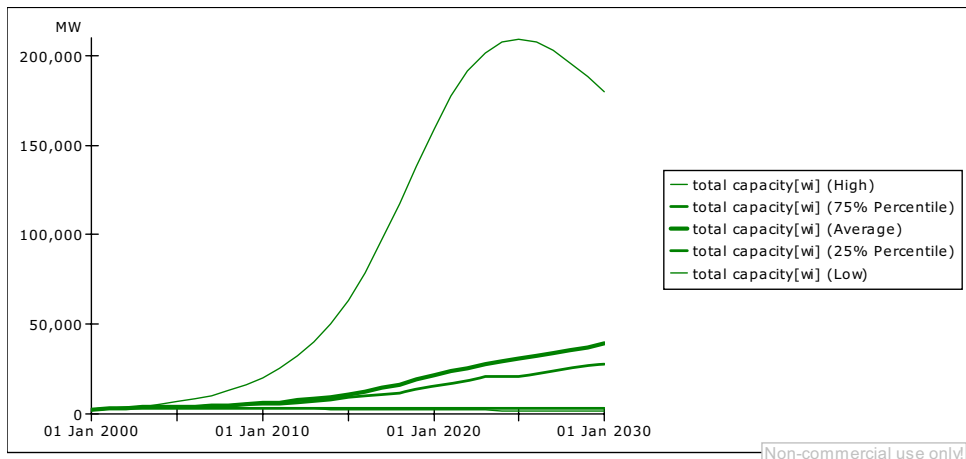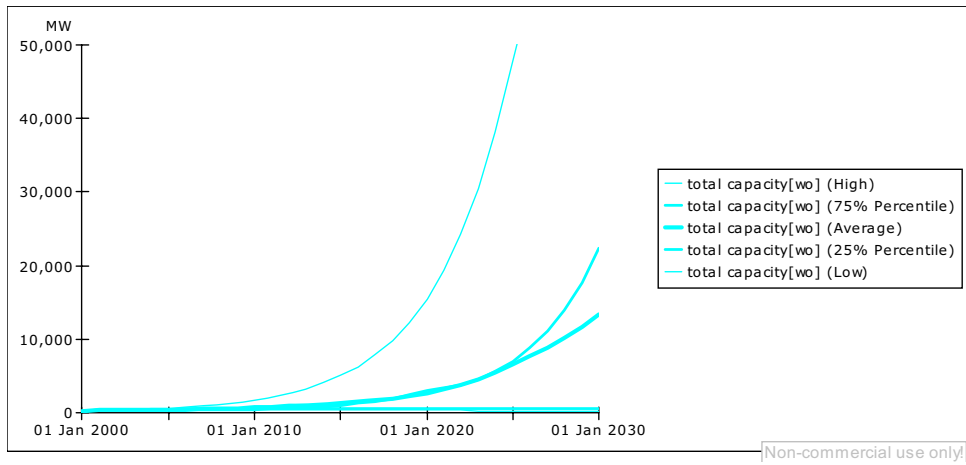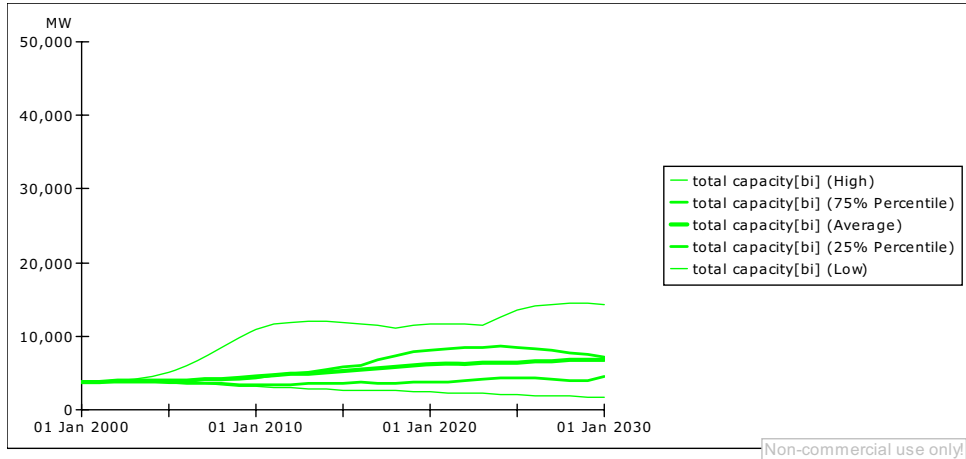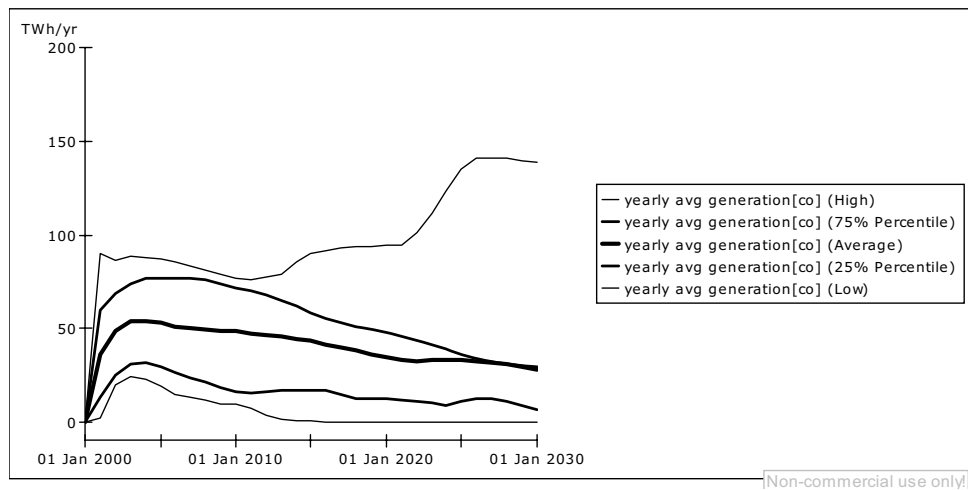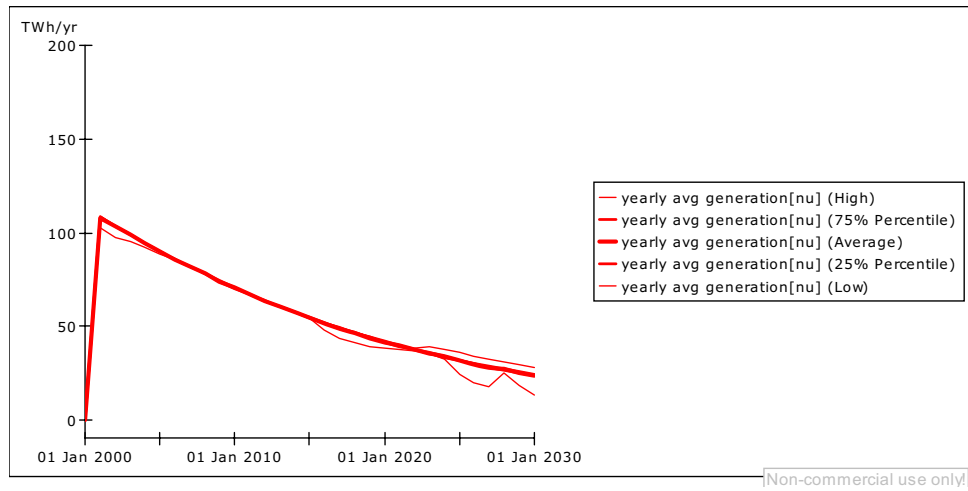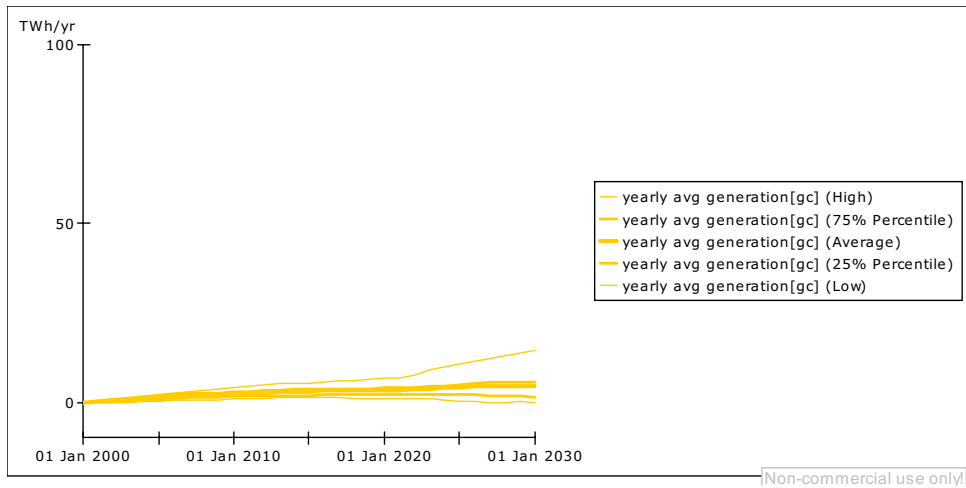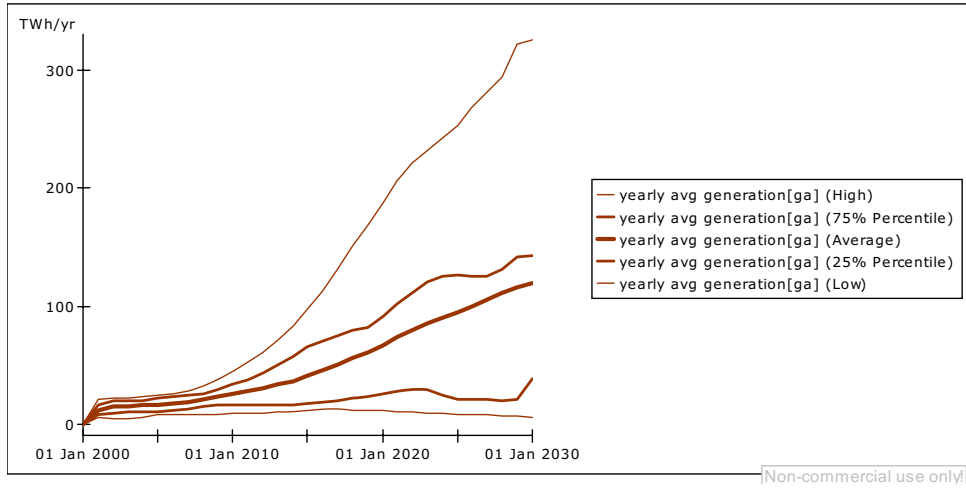
Figure 23.3 Installed Capacity

Figure 23.3 Installed Capacity

Figure 23.4 Generation
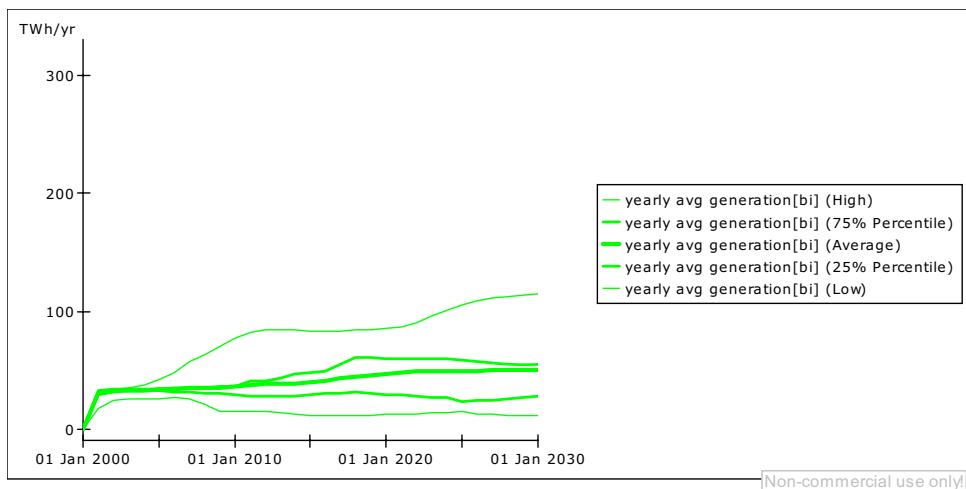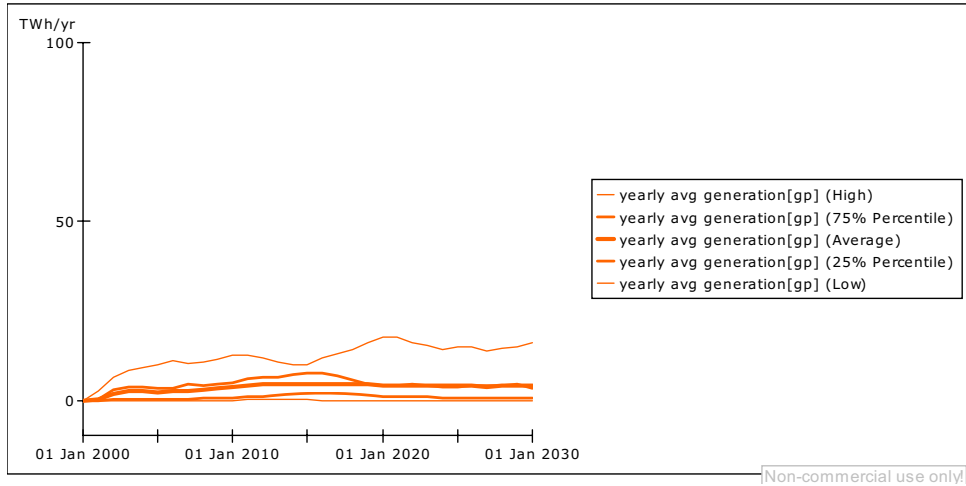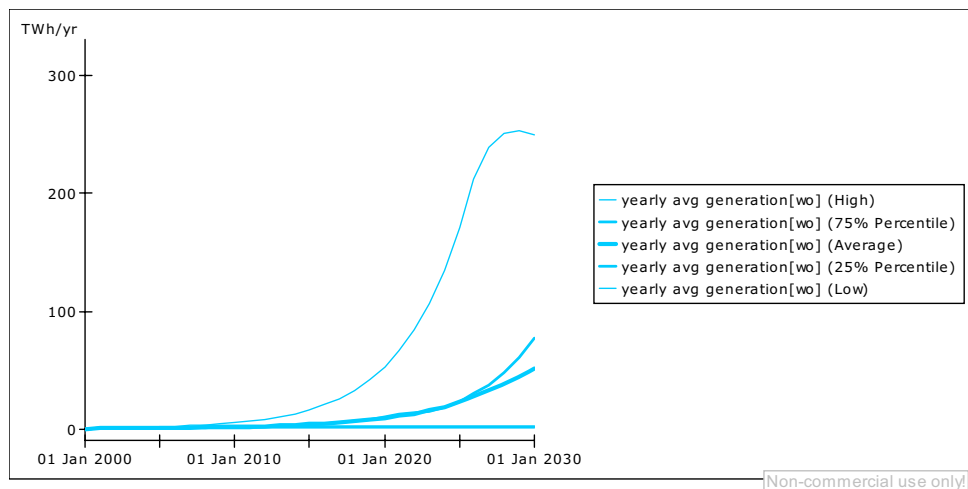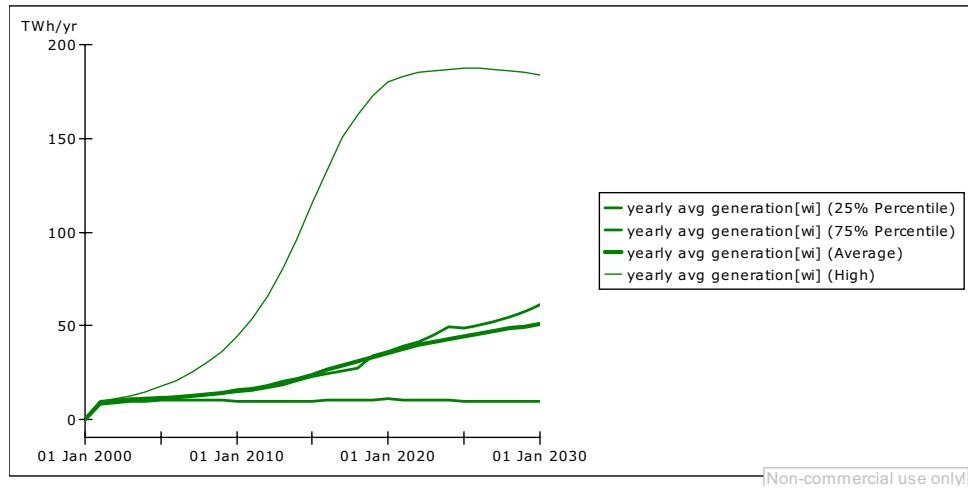
Figure 23.4 Generation

Figure 23.4 Generation

Figure 23.4 Generation
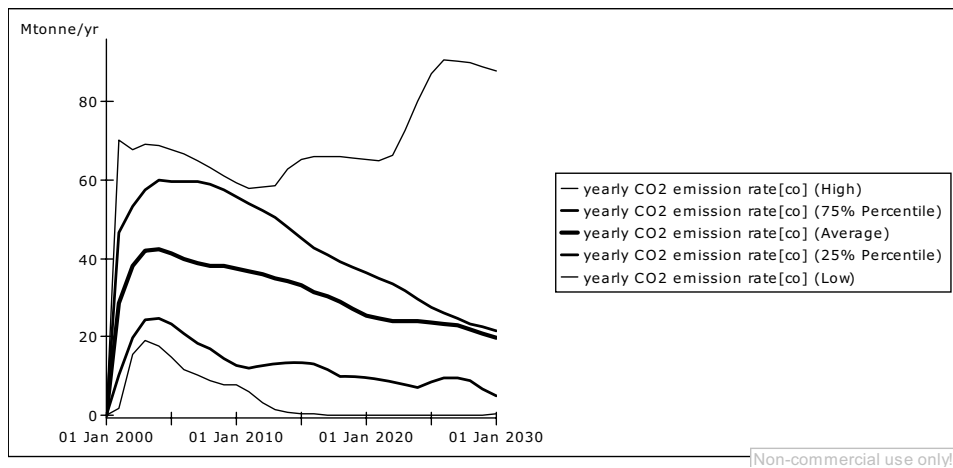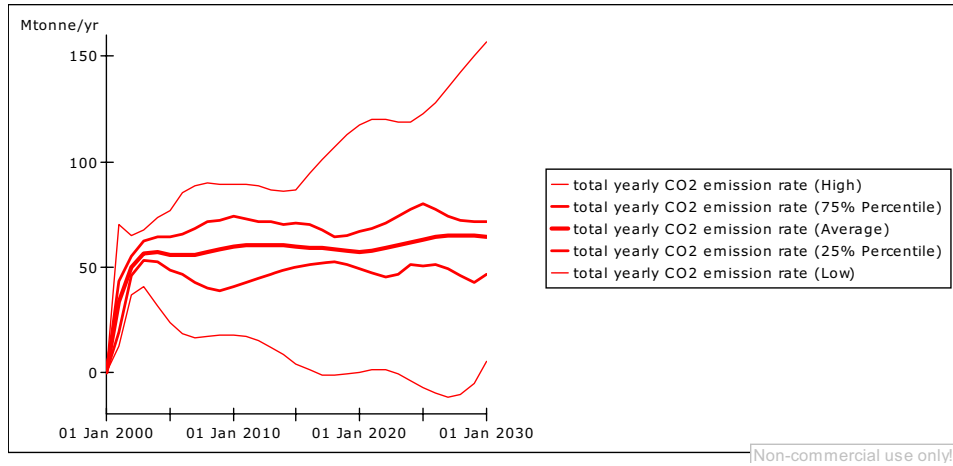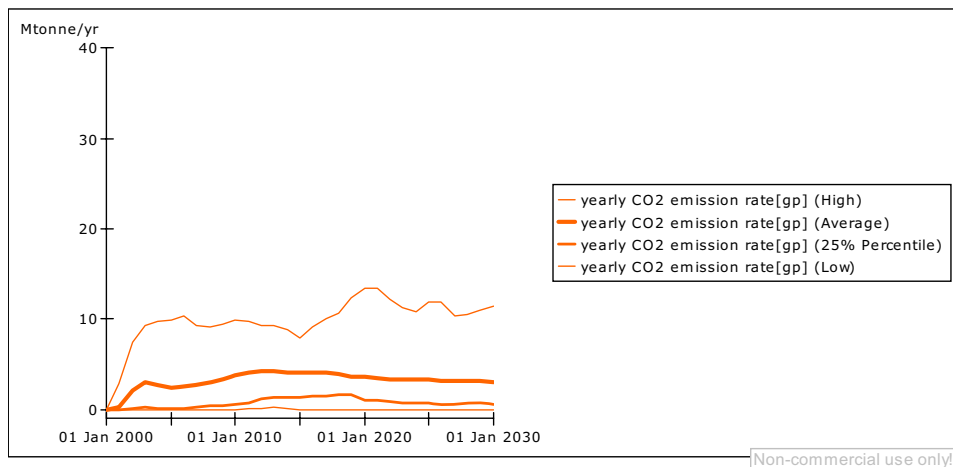
Figure 23.5 CO2-emissions

Figure 23.5 CO2-emissions
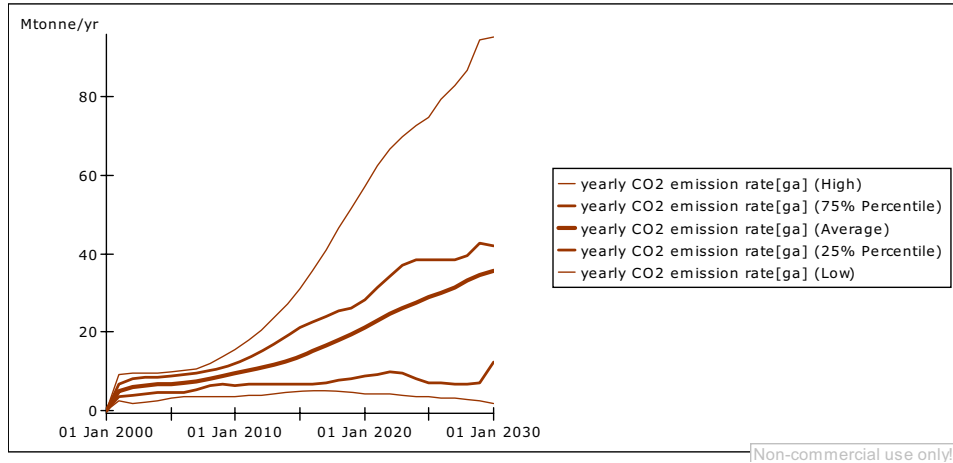
Single parameter variation

Since gas power is the cheapest technology available for new investments, natural gas is likely to determine the long-run market price and one can expect the electricity price to be very sensitive to changes in the gas price. However, the electricity price in *Figure 23.6* does not seem to vary significantly. The impact capacity development for gas and wind power, however is substantial.

Figure 23.6 Price - gas price vary between 0.7 - 1.5 NOK/Sm3
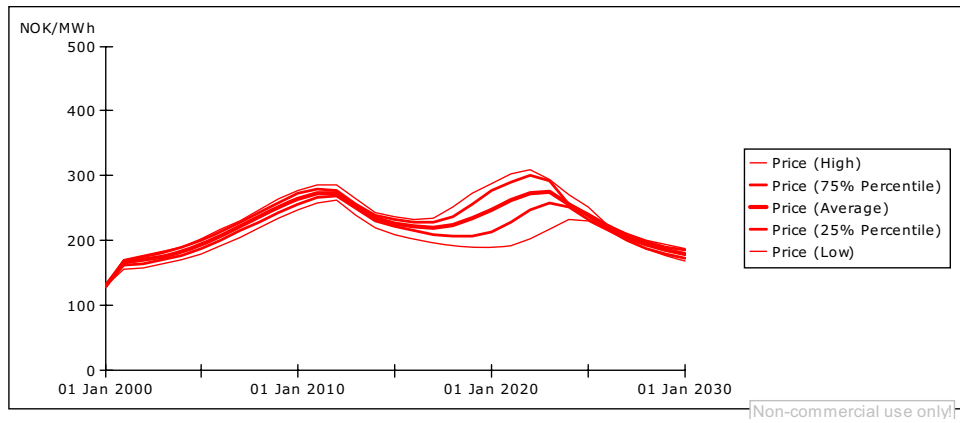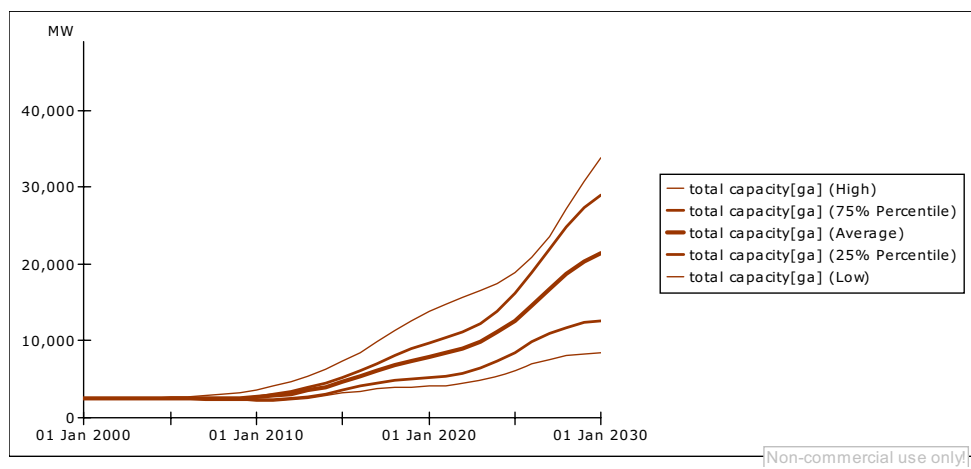
Figure 23.7 Installed capacity -gas price vary between 0.7 - 1.5 NOK/Sm3

Figure 23.7 Installed capacity -gas price vary between 0.7 - 1.5 NOK/Sm3
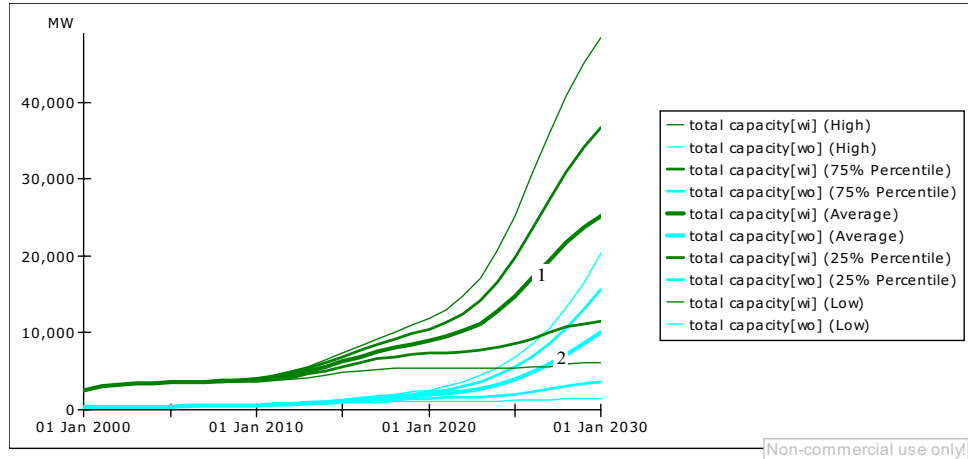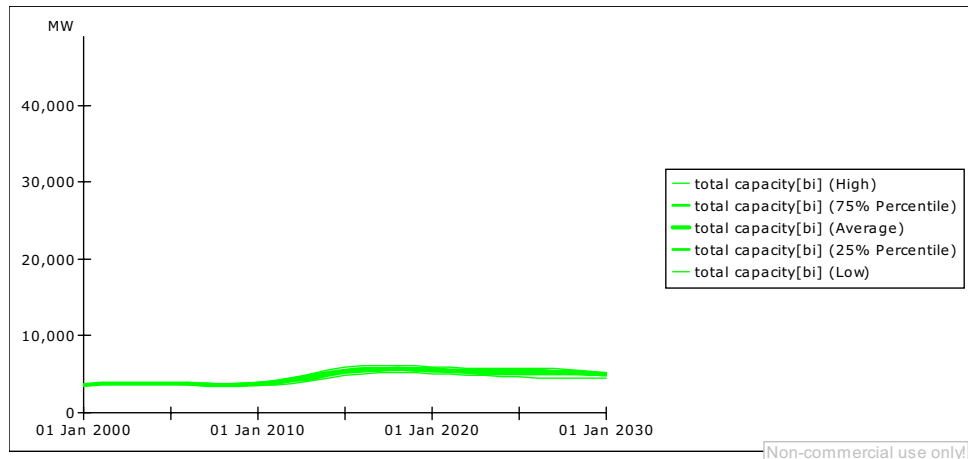
Figure 23.8 Generation - gas price vary between 0.7 - 1.5 NOK/Sm3
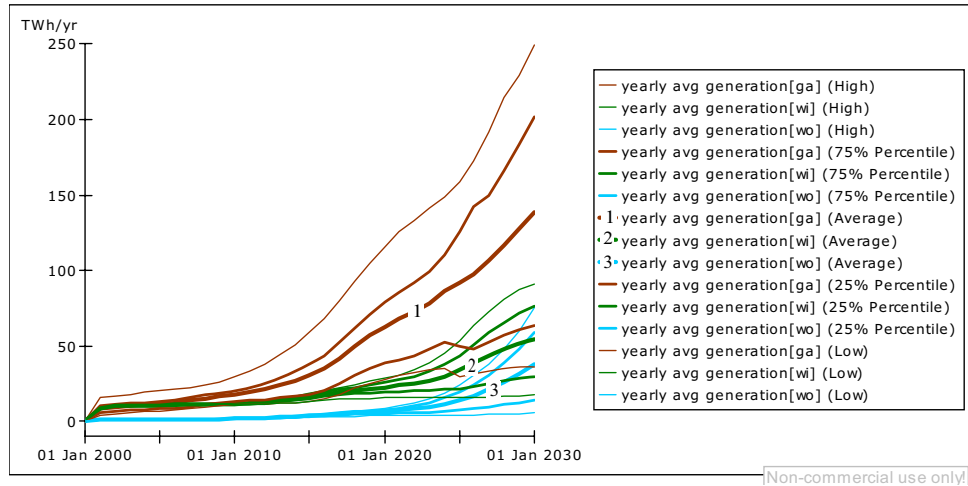
Fractional growth rate may vary depending on economic growth. The impact of varying the fractional demand growht rate is shown for demand development in *Figure 23.10*, and for the yearly generation in *Figure 23.11*. The corresponding change in yearly average price is

Figure 23.9 Price - fractional growth rate vary from 1- 2.5%/yr
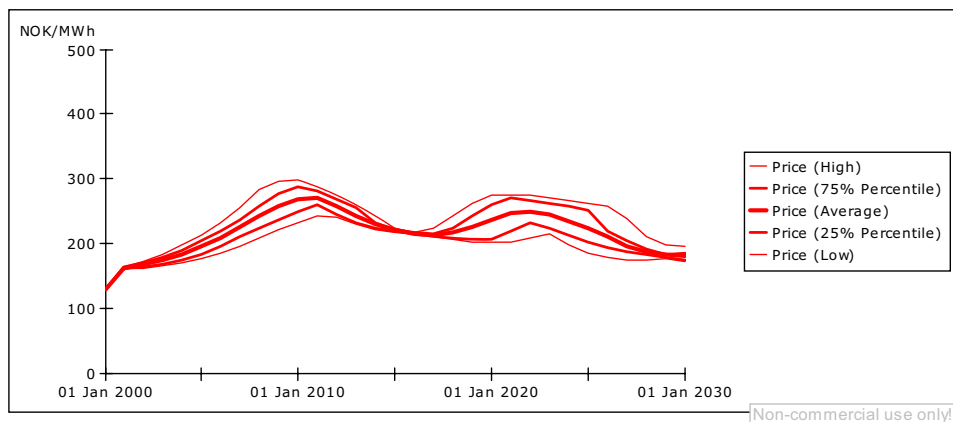
shown in *Figure 23.9*.

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Figure 23.10Demand - fractional growth rate vary from 1-2.5%/yr. Price elasticity -0.3
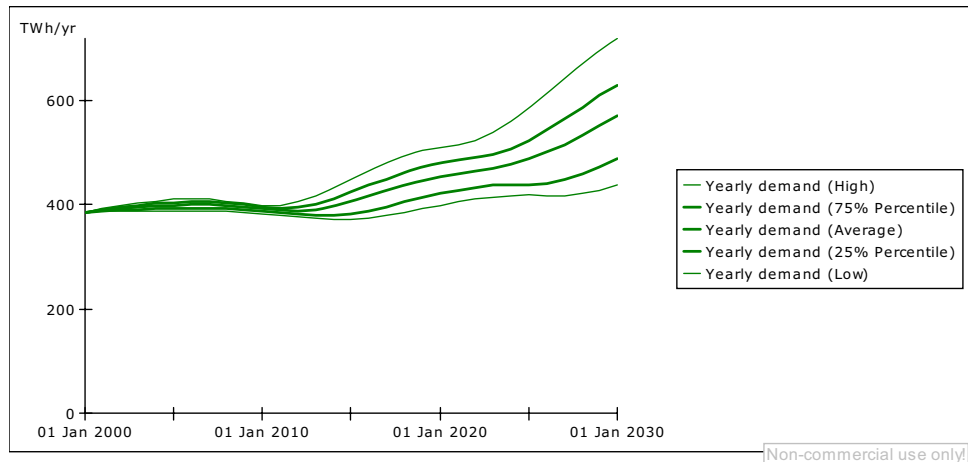
Figure 23.11Yearly generation - fractional growth rate vary from 1% - 2.5%/yr
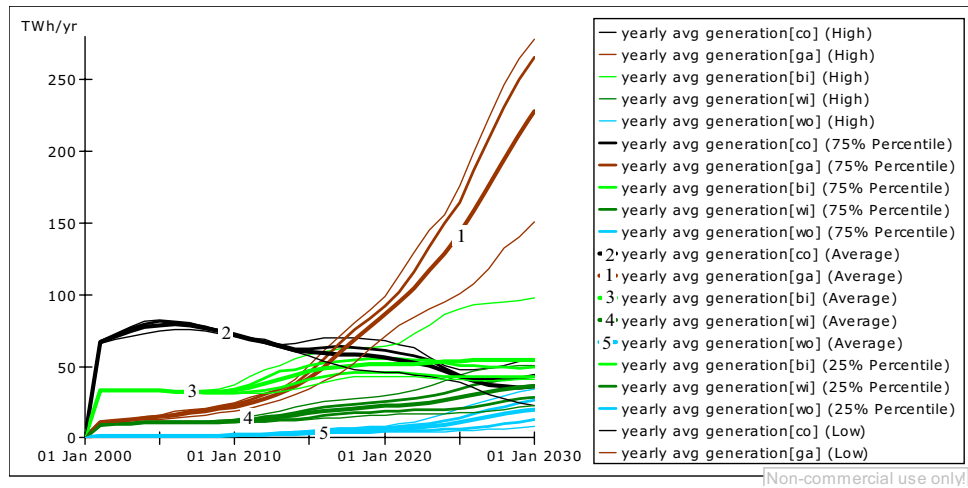
Technology progress can be regarded as somwhat uncertain, but how much does this uncertainty affect the model behaviour and the result? Price does not seem to respond much to the improvementes in the learning index (*Figure 23.12*). In terms of generation, we observe some spread towards the end of the simulation in *Figure 23.13*. Of course, if there were more favorable conditions for renewables, and the learning index is high, the sensitivity towards the learning index will be much more prominent. Compared to the simplified model and sen-

sitivity analyses from the simplified model, the increasing number of negative feedbacks in the more complex model will tend to reduce the variation or impact of single parameters.

Figure 23.12Price - Learning index vary +/- 40% from reference value
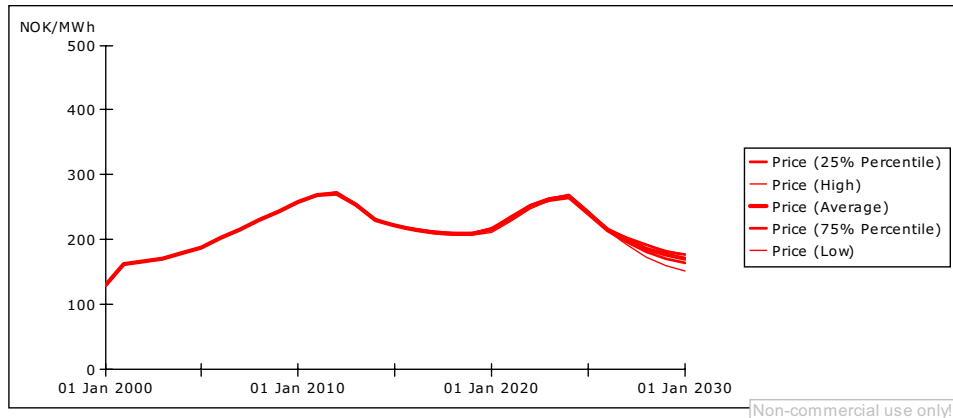
Figure 23.13Generation - Learning index vary +/- 40% from reference value
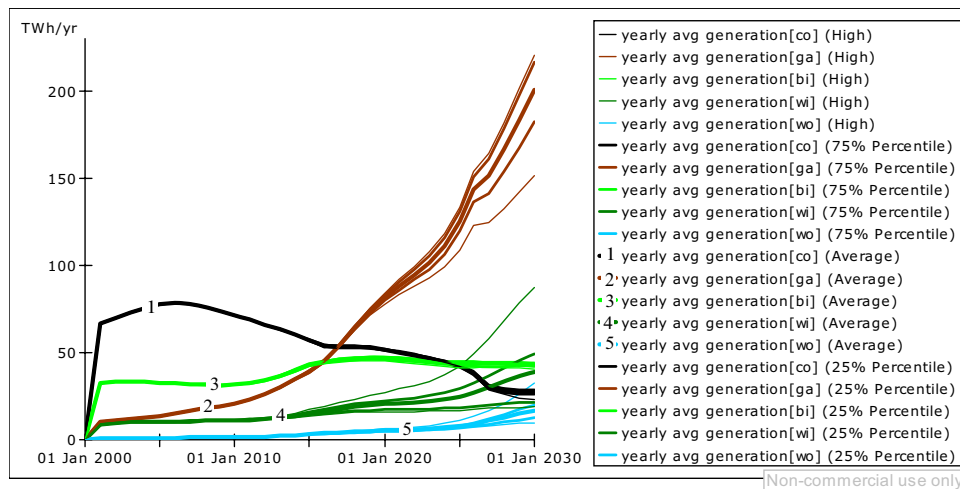
Resource availability is highly uncertain, but how much does this uncertainty affect the model behaviour ? The results shown here suggests that wind power is sensitive to resource

availability, while biomass is less sensitive. The resource availability did not have much impact on price.

Figure 23.14Installed Capacity - Resource potential vary +/- 50% from reference
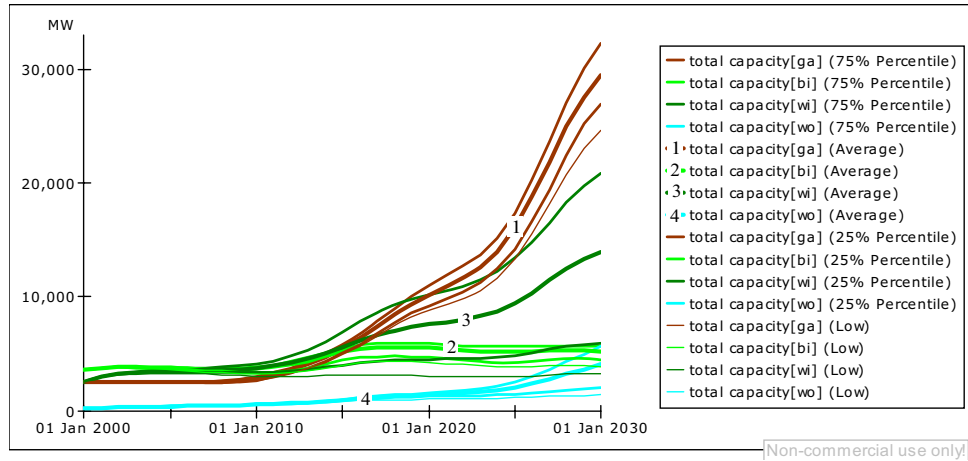
Figure 23.15Generation - Resource potential vary +/- 50% from reference
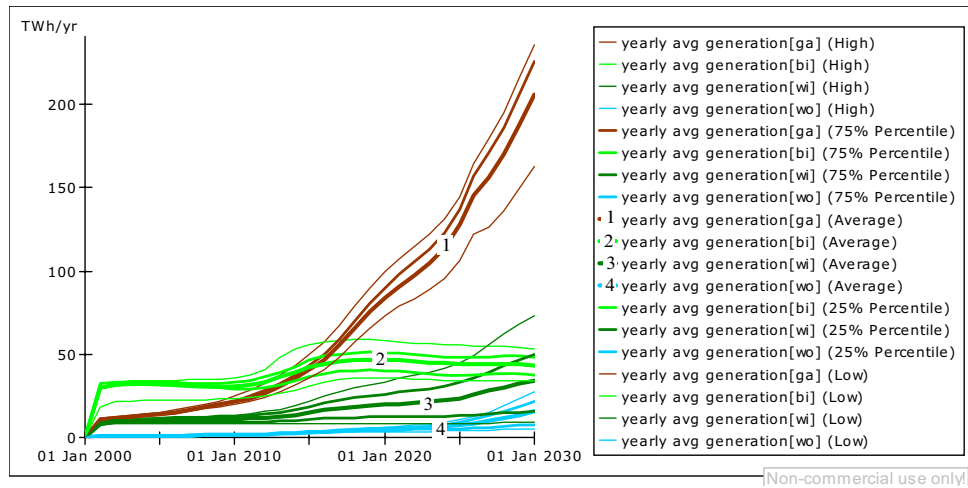
Appendix E - Publications

1. Vogstad, K, 2005: *Combining system dynamics and experimental economics to analyse the design of tradable green certificates.* Paper accepted for the HICCS 38 conference, Jan 3-6, Hawaii, 2005

2. Dimitrovski A, M Gebremichael, K Tomsovic, A Ford and K Vogstad, 2004: *Comprehensive modeling of the long term dynamics of investment and growth in electric power systems.* Presented at the EPNES Workshop, Puerto Rico, July 12-14, 2004 a) School of Electrical Engineering and Computer Science

3. Vogstad, K (2004): *Counterproductive environmental policies: Long term versus short term substitution effects of natural gas in a liberalised electricity market.* Proceedings, 22nd International Conference of the System Dynamics Society Jul 25-29, Oxford, England UK. ISBN 0-9745329-1-6 http://www.stud.ntnu.no/~klausv/publications/ Oxford04.pdf

4. Vogstad, K., I Slungård. and O Wolfgang (2003): *Tradable green certificates: The dynam ics of coupled electricity markets.* Proceedings, 21st International Conference of the System Dynamics Society July 20-24, New York City, USA. ISBN 0-967291-9-6 http:// www.stud.ntnu.no/~klausv/publications/TGC2003.pdf

5. Vogstad, K (2003). Designing market-oriented environmental policy instruments: The case of Tradable Green Certificates. In Proceedings, Marie Curie Workshop (forthcoming). Available online http://www.stud.ntnu.no/~klausv/publications/Petten.pdf

6. Vogstad K, A Botterud, KM Maribu and S Grenaa (2002): The transition from a fossil fuelled towards a renewable power supply in a deregulated electricity market. Proceedings, 20th International Conference of the System Dynamics Society Jul 28- Aug 1st, 2002, Palermo, Italy. Available online: http://www.stud.ntnu.no/~klausv/publications/ Palermo2002.pdf

7. Botterud A., M Korpås, K Vogstad and I Wangensten (2002): A Dynamic Simulation model for Long-term Analysis of the Power Market. Paper presented for the Power Systems Computation Conference, 25th -28th June 2002, Sevilla, Spain. http://www.stud.ntnu.no/~klausv/publications/Sevilla2002.pdf

8. Holttinen H., Vogstad K, Botterud, A. and R Hirovnen, (2001): Effects of large scale wind production on the Nordic electricity market. Proceedings from European Wind Energy Conference 2001, 2-6 July, Copenhagen, Denmark. Available online http:// www.stud.ntnu.no/~klausv/publications/Copenhagen2001.pdf

9. Botterud, A, Korpås, M, Vogstad, K-O., 2000: En langsiktig systemdynamisk kraft-markedsmodell. (A long-term power market model based on system dynamics) pp157-165, Proceedings, NEF Technical meeting 2000: Teknologi for effektiv elforsyning, Trondheim 27.-29. Nov 2000

10. Vogstad K, H Holttinen, A Botterud and JO Tande, (2000) System benefits of coordinating wind power and hydro power in a deregulated market. Proceedings from "Wind Power for the 21st Century, 23-25 Sept. 2000, Kassel Germany. Available online http:// www.stud.ntnu.no/~klausv/publications/Kassel2000.pdf

11. Vogstad K (2000):. Utilising the complementary characteristics of wind power and hydro-power through coordinated hydro production scheduling using the EMPS model.

Proceedings from Nordic Wind Energy Conference, NWPC' 2000, Trondheim, Norway 13-14 March 2000 pp107-111.Also available SINTEF TR A5187 ISBN 82-594-1799-5 Available online: http://www.stud.ntnu.no/~klausv/publications/Trondheim2000.pdf

12 Tande, JO and K Vogstad (1999):Operational Implications of Wind Power in a Hydro Based Power System. Proceedings, European Wind Energy Conference 1999 (EWEC 99'), Nice France, March 1999. Available online http://www.stud.ntnu.no/~klausv/publications/Nice1999.pdf

Note : The contents of publications 4,5 and 6 are largely covered by Part III in the book, and is therefore not provided in the appendix. Se www.stud.ntnu.no/~klausv to obtain publications online.

Paper 1

Combining system dynamics and experimental economics to analyse the design of tradable green certificates.

Paper presented at the HICCS 38 conference, Jan 3-6, Hawaii, 2005

Combining system dynamics and experimental economics to analyse the design of Tradable Green Certificates

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Abstract

A Tradeable Green Certificate (TGC) is a market oriented instrument to achieve targets of renewables in deregulated electricity markets. TGCs have already been implemented in several countries and experience is accumulating, but the behaviour of this market instrument is still uncertain with respect to price formation and efficiency. We give a survey of previous studies on TGC markets where they have found to be predominantly based on static comparative analyses and equilibrium models. We present a system dynamics analysis of the Swedish TGC market design. Depending on market design, TGC markets will work like asset markets, thereby enabling speculation. Using laboratory experiments, we analyse the decision rules of buyers and sellers and the resulting price formation under to various market designs. The decision rules are estimated using statistical methods. These rules are in turn used represent decision-making in the system dynamics model.

1 Introduction

In liberalised electricity markets, traditional and national instruments for promoting renewables do not neccessarily work efficiently [4][5]. This is particularly the case for the trans-national Nord Pool Market, in which coordination of electricity generation takes place across four countries, each with their different energy and environmental policies.

Harmonisation of taxes, rules, regulations and even energy and environmental policies is a neccessary continuation of the deregulation, and market oriented instruments such as Tradable Green Certificates (TGCs) have the potentials to provide a coordinated and efficient stimulus to renewables in transnational markets. TGC markets have already been introduced in some countries: Sweden, UK, Netherlands, Italy and Australia [1]. The EU considers a community-wide market to reach renewables targets. In the US, Renewable Portifolio Standards (RPS) have been adopted in several states [3]. An RPS requires utilities to include a specified amount of renewables in their portifolio of electricity generation, whereas a TGC is the instrument for monitoring and trading more flexible with these obligations. Texas has a TGC market in place for their RPS standard [2].

2 TGC markets

The main purpose of TGCs is to increase the share of renewable generation at minimum costs. TGCs are financial assets issued to producers of certified green electricity and can be regarded as a market-oriented environmental subsidy. An Issuing Body issues green certificates when generators registered in their database report monthly generation. Retailers must comply to their RPS obligations (renewable targets) every year by presenting the certificates to the Redemption Body, at which time the certificates are withdrawn from circulation. Between issuing and withdrawing, the certificates are accounted for and can be traded either bilaterally or at Nord Pool [7]. Transactions are reported and published electronically, stating price and quantity of the trade [6].

The purpose of the certificates is to monitor the amount of electricity generated from renewable energy sources. While the value of electricity is traded in the spot market, TGCs reflect the "green value" of renewables, in other words the additional price for renewables needed to provide new investments according to target shares of renewables (RPS). Authorities define a mandatory share of demand for renewable generation which is imposed on all retailers.

3 Survey of TGC studies

Experience on TGC markets now accumulating, though time delays in the capacity acquisition suggests it will take a long time before conclusions can be drawn. There are several uncertainties concerning price formation and efficiency. In particular, the first year of the Swedish market showed prices twice as high as expected.

Numerous studies have been performed already, but, with a few exceptions, these studies are based on comparative static analysis and partial equilibrium models. As we will show in section 4, dynamics of the TGC market can pose problems that are not captured by comparative statics and equilibrium approaches. We will limit our study to the Nord Pool market and the Swedish TGC market design.

Static comparative analysis of TGC markets and market power have been analysed by Amundsen and Sørensen and Amundsen and Nese respectively [8][9]. Nielsen and Sky-

tte studied the interactions between the TGC and electricity markets [10].

Prior to the introduction of the Swedish TGC market, a number of studies were made, including simulations in Markal [11]. While the above studies yielded some important insights under equilibrium conditions, we will review two conclusions stated below from a system dynamics approach in section 4 :

• The TGC price will, in principle, equal the long run marginal cost of new generation from renewables.

• TGC prices will be volatile and subject to changing weather conditions from year to year unless flexible mechanisms such as borrowing and banking (see below), or flexible generation is implemented.

The EU are considering adopting a community-wide TGC trading scheme to reach each of the countries' renewables targets.

The REBUS (Renewable Burden Sharing) study assessed the renewables potentials and the costs of reaching their renewables targets [12].

As a follow-up, the ADMIRE project (Assessment and Dissemination activity on Major Investment Opportunities for Renewable electricity in Europe using the REBUS tool), expanded the REBUS analysis to incorporate the effect of uncertainties, limited information and lead times into the model [13]. The conclusions of this project were that uncertainties among investors will increase the costs of reaching renewables targets, and that longer time horizons for renewables targets and long-term agreements must be implemented to reduce investors' risks. Furthermore, lead time will cause prices to ramp up during the first phase of a TGC market, but flexible mechanims can reduce this problem.

RECeRT (The European Renewable Electricity Certificate Trading Projetct) aimed analyse trading mechanisms by using economic laboratory experiments [14]. A particularly interesting study included in the project was the effect of various market designs on price formation by Schaeffer and Sonneans [15]. The results showed that there were no restrictions on banking, prices tended to increase towards the penalty price.

4 A systems dynamics model of the TGC market

In this section we will give a dynamic representation of the TGC market that can reveal some different insights from that of the static approaches. The objective of a TGC market is to provide a price signal that reflects the additional costs required to meet the TGC targets. We therefore need to consider investments in renewable capacity, the demand

for certificates and the resulting price. *Figure 1* shows how
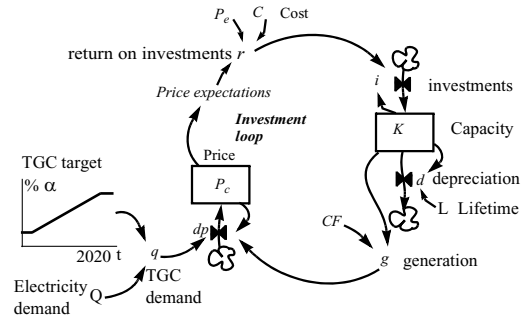
Figure 1 TGC price P_c formed by TGC demand q and renewable generation g stimulating investments in new capacity K.

the price of certificates influences the investments in new renweable capacity. Note that renewable generation is determined by the stochastic wind or rain (defined by the capacity factor CF.

4.1 TGC demand

The TGC demand is defined as an increasing share of total demand over a predefined time period. The variables are defined as follows:

Q - yearly electricity demand in [TWh/yr]

q - TGC demand in [TWh/yr]

α - TGC target in fraction of demand [1]

Thus,

$$q(t) = \alpha(t) \cdot Q \qquad (1)$$
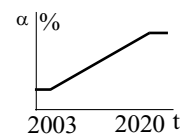
Figure 2 TGC target as a percentage of demand

To simplify our analysis, Q is kept fixed since the fractional increase of α will be much larger than fractional increase of Q.

4.2 Renewable capacity

Renewable capacity is defined as follows:

K, K_0 - Installed and initial capacity in [MW]

d - Depreciation rate of renewables in [MW/yr]

i - Investment rate of renewables in [MW/yr]

L - Average lifetime of installed capacity in [yr]

I_{eq} - Fractional equilibrium investment rate in [1/yr]

g - Yearly electricity generation in [TWh/yr]

CF - Average capacity utilisation measured [hr/yr]

i_p - Effect of profitability on investments [1]

r - A normalised indicator for return on investments [1]

The stock of renewable capacity is then :

$$K(t) = K_0 + \int_{t_0}^{t} (i(t) - d(t))dt \qquad (2)$$

and yearly generation is

$$d(t) = \frac{K(t)}{L} \qquad (3)$$

$$i(t) = I_{eq} \cdot i_p(r) \cdot K(t) \qquad (4)$$

$$g(t) = K(t) \cdot CF \qquad (5)$$

where $K_0 = 5585$, $L = 20$, and $I_{eq} = \frac{1}{L} = 0.05$

Equation (2) states that the stock of installed capacity is the Initial capacity K_0 at t_0 plus the cumulative investment rate $i(t)$ defined by (3) minus the depreciation rate $d(t)$ (4) over the time interval $t_0 \ldots t$.

Fractional investments rate is defined as $I_{eq} = \frac{1}{L}$. In equilibrium, $i(t) = d(t)$ and there is no net change in capacity.

4.3 Market dynamics

A dynamic price formation can be modelled in terms of the the *excess demand* function previously used to study price stability in economic markets by Arrows [23], and also used to represent price dynamics in electricity markets [24]. Let

$P_c(t)$ TGC price [NOK/MWh]

Then,

$$P_c(t) = P_{c,0} + \int_{t_0}^{t} P_c(t) \cdot \left(\frac{q(t) - g(t)}{q(t)} \right) \cdot \frac{1}{\tau} dt \qquad (6)$$

The expression in (6) states that the TGC price adjusts in proportion to the discrepancy between supply and demand over the characteristic adjustment time interval $\tau = 1 \, yr$, which is the yearly compliance period of the TGC market.

4.4 Investment decisions

Investment decisions are based on profitability expectations of new capacity. With a TGC market, expected profitability is a function of *expected electricity price*, *expected TGC price* and *long run marginal costs of renewables*.
For simplicity, we assume the electricity market price and the long run marginal costs of renewables to be fixed and known to the investor.

$P_e = 200$ - Electricity price [NOK/MWh]

$C = 300$ - Levelised energy cost renewables [NOK/MWh]

$\tilde{P}_c(t)$ - Expected TGC price [NOK/MWh]

The TGC price however, is a function of supply and the TGC demand. In the abscence of futures markets, investors need to make *expectations* about future prices when investing in new capacity. In a perfect market, investors often assume that the market price converges to the average long-run marginal costs of new generation, C (see discussion in section 3). As we will se at the end of this section, this is *not* the case in growing markets. Expectations of future TGC prices, $\tilde{P}_c(t)$, can be modeled in several ways. One way is to assume *rational expectations*, suggesting that investors are perfectly able to predict future prices and match demand at all times. But the price is dependent on capacity acquisition, for which there are physical limitations. Even with rational expectations and perfect foresight, TGC supply and demand does not neccessarily equilibrate. We will however assume investors form *adaptive expectations:*

$$\tilde{P}_c(t) = \tilde{P}_{c,0} + \frac{1}{T} \int_{t-T}^{t} (P_c(t) - \tilde{P}_c(t))dt \qquad (7)$$

where T is the average time period over which the expectations were formed. Investors' price expectations are thus exponential weighted averages of recent prices over the time interval $(t - T) \ldots t$.

As an indicator of profitability we define

$$r(\tilde{P}_c) = \frac{P_e + \tilde{P}_c(t)}{C} \qquad (8)$$

which is a normalised, simplified profitability indicator expressing the ratio of expected income versus levelised costs per energy unit.

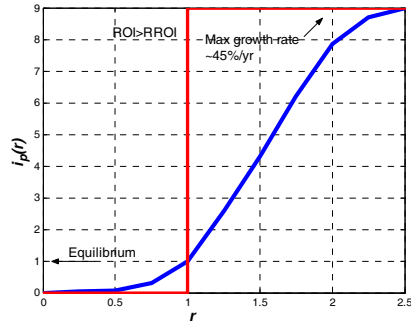*Figure 3* shows the table function $i_p(r)$ that defines the

Figure 3 investment multiplier $i_p(r)$ **as a function of normalised return on investments,** r

effect of profitability on investment rate. It has the shape of a cumulative distribution function that can be analytically derived from the factors underlying the profitability assessment. The curve represents an aggregate of a large number of projects for renewable generation, where wind conditions, site locations, profitabity requirements of investors, etc., vary from project to project. Thus they are stochastic variables with a mean value and a distribution around the mean value. Only the most favorable projects will be realised at the lower end of r, while even the least favorable projects will be realised at the upper end of r, corresponding to a 45% growth rate in eq. (4). When $r = 1$, the normalised return on invesments is marginally profitable, so that $i(t) = d(t)$. For comparison, a step function shows investment criteria of an individual project, where investments are made if $r > 1$ ..

There is also some empirical evidence for this relationship. Morthorst [16] observed the relationship between profitability and investments by private owners of wind turbines during the period 1985-1998 (see *Figure 4*).
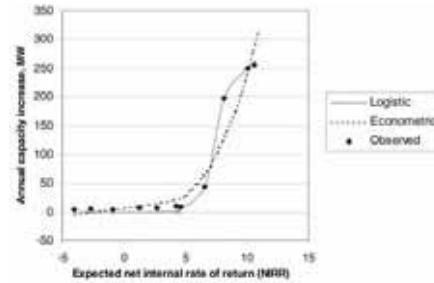
Figure 4 Net internal rate of return (horisontal axis) versus investment rate in MW/yr along the (vertical axis) Source: Morthorst [16]

5 Investment dynamics and the impact on TGC prices

We will now consider the behaviour of the simplified TGC market model under some idealized assumptions before the TGC market design is discussed. *Figure 5* shows the TGC market behaviour under four different assumptions on investor's price expectations :

1) *Subsidy*: For comparison, we simulate investments when receiving a fixed subsidy of 188 NOK/MWh, which is just enough for investments to fulfill TGC obligations by 2023.

2) *Myopic* : Assumes tomorrow's prices will be like today's prices.

3) *Adaptive* : Exponential weighted average of prices over the recent time period $T = 1$ year as defined in eq. (7).

4) *Forecast* : A trend extrapolation of the exponentially weighted average in 3) is projected four years into the future.

. The upper graph displays the sluggish investment dynam-
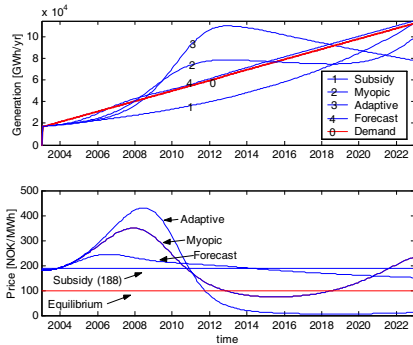
Figure 5 Simple model, development in generation and TGC demand. Lower graph: TGC price, long run marginal costs and average TGC price.

ics, due in part to time delays of investment decisions and the price discovery process. Renewable generation usually cannot be controlled in the short term (must-run units), and the only way to adjust their level of generation is through new investments or withdrawal of old units. The resulting long term price fluctuations can be seen in the same figure.

Interestingly, the average TGC price level is significantly higher than the difference between C (long run marginal costs of renewable generation, LRMC) and the electricity market price P_e. While $C - P_e$ indicates a difference of 100 NOK/MWh needed to close the cost gap for profitability, the average TGC price is 188 NOK/MWh (!). The reason for this is that the equlibrium approach using average values does not give a good indication of the price level when facing a dynamic situation of growth. To increase capacity, projects above the equilibrium costs must be developed in order to meet the growing TGC demand. The steeper growth rate, the higher the TGC price needed. These effects also appeared in the REBUS ADMIRE study.

Figure 5 shows that time delays in the price expectation formation process significantly contribute to under- and overinvestments, except for the Forecast expectations. However, forecasts must be made with care, as they can cause significant overshoots if the time horizon for trend observations are too short to filter out fluctuating data.

6 TGCs with banking and borrowing

Until now, we considered a fixed, average yearly capacity utilisation, although the supply from renewables such as

wind and hydro can vary considerably from year to year. One important aspect of renewable generation (at least the type of generation defined in the Swedish TGC market) is that *renewable generation* cannot be controlled in the short term. Wind power, small scale run-of-river hydro and CHP district heating are not price sensitive. Thus, there is no short-term feedback (as with conventional units) that adjusts capacity utilisation (CF). The supply of TGCs can therefore only be controlled by new capacity acquisition, which makes the supply side of the TGC market sluggish as was pointed out in previous sections. Price fluctuations in the TGC market itself does not pose any problem for the physical operation of renewable generation, as the TGC market is a purely financial market. If however, the TGC market is to fulfill its intention of providing price signals to investment in new capacity, long term fluctuations are not desirable as they can trigger investments that are not profitable in the long run.

6.1 Borrowing and banking as mechansims to increase the flexibility of the TGC market

Of main concern in previous studies, has been the yearly stochasticity of renewables, and the proposed solution is to introduce *banking* and *borrowing* as flexible mechanisms to account for this stochasticity.

Banking is defined as the possibility of storing certificates from one year to later years. Suppose during windy years, there will be an excess supply, and consequently low TGC prices. Sellers may want to save these TGCs for calm years, when the prices are higher. Banking will then have the effect of smoothing out price differences between years.

Borrowing is the possibility for a buyer, with TGC obligations, to postpone parts of the obligation to subsequent years. Suppose market prices are high due to a calm year. The buyer may then want to postpone parts of his obligation to next year, when prices fall.

With unlimited lifetime of TGCs, all certificates have the same value, which improves the liquidity and the simplicity of the market. If on the other hand, certificates have a limited lifetime, their value will be time-dependent. New certificates will be more attractive than certificates that are about to expire.

6.2 Model representation of TGC trading

Consider now *Figure 6*. Sellers receive TGCs on a monthly basis according to their amount of renewable generation. The TGCs then enter the sellers stock of TGCs, and he can sell his TGCs at convenience, independent on time of gen-

eration. Similarly, buyers can buy TGCs in the market for later use.

But which factors determine the purchase and sales of TGCs and what are the trading strategies ? The possibility of storing certificates open up new options for speculation. Of particular concern is the inflexible acquisition of new capacity, that can potentially be exploited by sellers, for instance by witholding certificates.
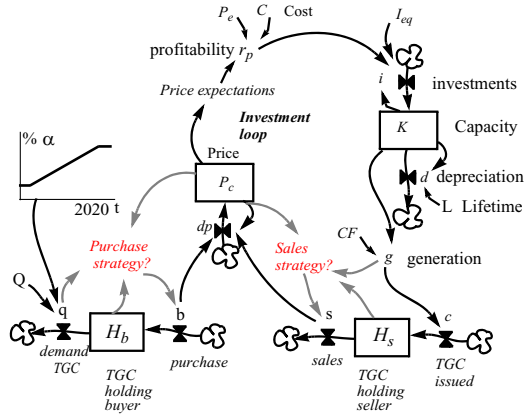

Figure 6 TGC market with buyers and sellers

The possibilities for strategic behaviour and speculations depend on the given market design. To analyse trading under various conditions, we designed a network simulation game, where our model is converted in to an experimental economics laboratory, which will be describe in the section 7. We now expand our model to include buyers and sellers in the TGC market:

c - certificates issued [TWh/yr]

s - TGCs sold [TWh/yr]

H_s - Sellers holdings of TGCs [TWh]

b - TGCs purchased [TWh/yr]

H_b - Buyers holding of TGCs [TWh]

In particular, we are interested in the decision policies governing the sales and purchases s and b. Let us denote these as :

Sales strategy(P_c, g, H_s)

Purchase strategy(P_c, q, H_c)

$$H_s(t) = H_{s,0} + \int_{t_0}^{t} (c(t) - s(t)) dt \qquad (9)$$

$$c(t) = g(t) \qquad (10)$$

$$s(t) = \text{Sales strategy}(P_c, g, H_s) \qquad (11)$$

Similarly,

$$b(t) = \text{Purchase strategy}(P_c, q, H_c) \qquad (12)$$

$$H_b(t) = H_{b,0} + \int_{t_0}^{t} (b(t) - q(t)) dt \qquad (13)$$

where $q(t)$ is as previously defined in (1).
With these modifications, the price formulation in (6) changes to .

$$P_c(t) = P_{c,0} + \int_{t_0}^{t} P_c(t) \cdot \left(\frac{s(t) - b(t)}{b(t)} \right) \cdot \frac{1}{\tau} dt \qquad (14)$$

In equilibrium models assuming perfect market conditions, it is usually assumed that bids equal the marginal operational costs. In the TGC market, there marginal costs are not present. The decisions of how much to borrow or how much to bank makes the problem of buying and selling in principle a *dynamic optimisation problem*, similar to that of hydro scheduling with reservoir storage.

There are some important differences, however. Unlimited banking creates a longer time horizon of the decision problem, whereas hydro reservoirs constrains the time horizon to approximately one year. Whereas the value of storing hydro reservoirs depends on the operational costs of alternative thermal generation in the system, the value of a TGC depends on the future expected market prices, influenced by fundamentals such as the cost of new generation, penalty prices, TGC demand ,TGC holdings and the action of others. Thus the TGC market has the characteristics of an asset market.

Faced with this complexity, the market participants are likely to adopt various heuristic trading strategies. In the next section, we try to capture the trend following strategies by converting our dynamic model into an experimental laboratory with interactive players.

7 Using laboratory experiments to analyse trading strategies

Experimental economics is a well established field within in economics that also has contributed to the deregulation of electricity markets. Experimental economics was pioneered by Vernon Smith [25] who received the Nobel price for his contributions to the field. In electrical engineering, internet-based simulation tools have been developed [26] to analyse competitive behaviour in electricity markets with the use of laboratory experiments [27][28] where transmission constraints can provide opportunities to exert market power.

Building a computer laboratory where market participants can trade under controlled conditions and observations, enable us to test various economic hypotheses and to test various market designs. Moreover, hypotheses concerning trading strategies can in principle be analysed. If trading strategies and representative heuristic rules can be derived and described mathematically, these decision rules can in turn be implemented in other simulation models to test market designs more efficiently to reduce the number of time-consuming laboratory experiments.

This study focuses on the price formation in the TGC market, in particular how various trading strategies can influence the price formation and the efficiency of the TGC market. Being a purely financial market, a representation of the physical transmission system was not needed in this study. It is the market design itself and the long-term dynamics of investments that may cause undesirable modes of behaviour.

A laboratory experiment was conducted at NTNU (Norwegian University of Science and Technology) during 2003 to estimate plausible trading strategies and its influence on the price formation. The *Buyers trading strategy* and the *Sellers trading strategy* as shown in *Figure 6* was managed by 10 players (5 buyers and 5 sellers) through a GUI in a computer based network game, where they could observe relevant market information on TGC's needed, TGC's issued, the resulting TGC price, and their holdings, see *Figure 7*. Researchers in electrical engineering from SINTEF

Sonnemans [15] that most closely resembled the market design conditions of our experiment.

Both simulations shows that the price was driven far above the expected equilibrium price (i.e. the price needed to stimulate sufficient investments), followed by a subsequent price crash thereafter. The experiment indicated withholding during the intial stage of the simulation and accumulation of TGC's at the sellers, resulting in overinvestments and subsequent price crashes in the later part of the simulation.
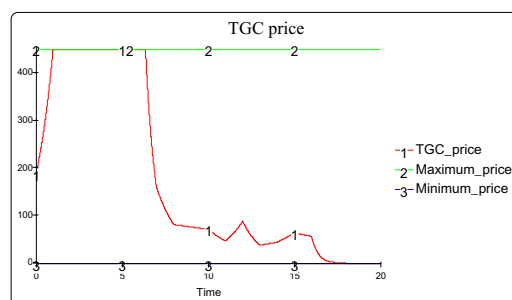
Figure 8 Price formation in the NTNU TGC laboratory experiment, March 2003.

Figure 7 TGC market laboratory experiment at NTNU

Energy Research and representatives from the Norwegian regulating authorities dealing with incentives for renewables participated in the experiments.

The computer experiments adopted the Swedish market design in which unlimited lifetime (up to 100% banking) of certificates, and no borrowing. The resulting price formation is shown in *Figure 8*. A similar behaviour on price formation was observed in the experiment by Schaeffer and

Figure 9 Laboratory experiment with 100% banking and 50% borrowing . Source: *[15]*

The Swedish TGC market has now been in operation for one year. The expected market prices prior to implementation was expected to be around 100 SEK/MWh. *Figure 10* (adapted from *[6]*), shows historical TGC prices of the Swedish market during the first year. As can be seen, the TGC price rapidly settled at the penalty price level. There may be several explanations for this.

The uncertainty of the future market development and the short time horizon (Targets are set until 2010) increases investors risk and thereby prices. A longer TGC market time horizon is needed.

In addition to that, our analysis in section 5 showed that the TGC price must be higher in a growing market to keep pace with the increasing target (especially during the first years), than in a market in equilibrium. Our dynamic model captures this effect.

Secondly, strategic behaviour such as withholding and trend following combined with the few possibilities for short term increases in generation can cause prices to boom.

After just one year of operation, the effect of lacking investments are less likely to influence the first year's price formation. By the end of the year, some TGCs were transfered to this years period, indicating a build-up in holdings. These observations are in line with our experimental results.

Figure 10 Swedish TGC price history May 2003 - June 2004.

The results from our experiments were insufficient to provide a statistical estimation of decision rules. It turned out to be quite difficult to estimate decision rules with statistical significance having a limited number of experiments. The decision process is quite complex, as there are many variables to consider. We are however aiming at conducting a sufficient number of experiments in the future to be able to test various hypotheses of decision rules.
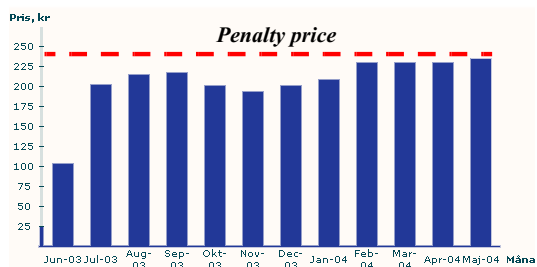
We did, however hypothesize some decision rules that was implemented to represent trading strategies in the simulation model. *Figure 10* shows the results a simulation run where a combination of *trend following* and *value trading/ fundamentalist* strategies were implemented. Some stochasticity of wind was also implemented, and the simulation shows the average price formation and percentiles from a Monte Carlo simulation of various wind series.

These results are also in accordance with the experimental
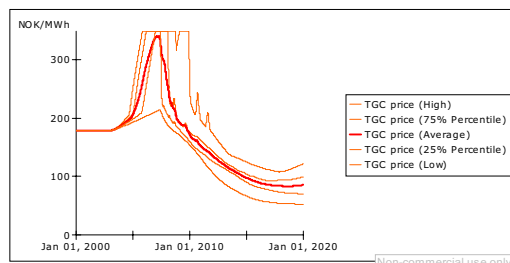
Figure 11 TGC models with hypothesized value trading and trend following behaviour implemented. TGC market starts in 2005 and runs until 2020.

results. Future work will be to conduct more laboratory experiments in order to assess the heuristic decision rules governing trading strategies.

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Paper 7

A Dynamic Simulation model for Long-term Analysis of the Power Market

Paper presented for the Power Systems Computation Conference, 25th -28th
June 2002, Sevilla, Spain

A DYNAMIC SIMULATION MODEL FOR LONG-TERM ANALYSIS OF THE POWER MARKET

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Abstract – This paper presents a new model concept for long-term analysis of deregulated power markets. In the model we try to capture the main factors influencing long-term development of the power system. In the deregulated power markets, investment decisions are no longer part of centralised planning and optimisation. Investors' lack of perfect foresight, together with permissions and construction delays, could possibly result in periods of overcapacity or capacity deficits in the system. By using a dynamic description of investments we are able to include these effects into our model. The average spot price in the power market is calculated from year to year, using a linear optimisation algorithm. The electricity price in turn influences investments in different technologies for generation and end-use of electricity. A modelling technique based on system dynamics is used to model these investment decisions. Public authorities and energy companies are potential users of the model, for learning and decision support in policy design and scenario planning. Results from a case study of the deregulated power market in Norway are included to illustrate potential use of the model.

Keywords: power market, simulation, system dynamics, policy design, scenario planning

1   INTRODUCTION

The ongoing deregulation of power markets around the world presents the electric power industry with several new challenges. Long-term investment planning under the new and more uncertain conditions is one of them. The importance of making the right investment decisions has increased in the new environment, where the utilities have less influence on what price they can charge from their customers in the future. A fundamental understanding of how the power market is likely to work in the long run is therefore of major importance to improve decisions on technology choice, size and timing of system expansions. Consequently, new planning approaches and models are needed to better understand the conditions in the deregulated electricity markets, as pointed out in [1].

The new organization of the industry also creates challenges for the authorities in a region or country. Even though deregulation has left regulating institutions with less direct influence on the power market, the authorities still want to make sure that the power system develops in a desirable direction. A balanced development of supply and demand, accompanied by non-fluctuating prices is usually looked upon as one indication of a well-functioning market[1]. Most authorities are also aiming at lowering the environmental impact of the power supply. A well-functioning power market in the long run can be achieved by creating the right incentives for investments on both supply and demand side. To create such incentives the authorities also need comprehensive knowledge about how different factors influence the long-term development of the power system.

This paper presents a new model concept for long-term analysis of the power market. The model is a possible tool for increasing the understanding of the prevailing conditions in deregulated power markets. It is specifically suitable for scenario planning, and both energy companies and public authorities could make use of the model in their long term strategic planning. In the model we calculate the annual average electricity price using a linear optimisation algorithm, while the description of investment decisions is based on system dynamics. In the first part of the paper we discuss investment dynamics in the power market, and how this is incorporated into traditional and new power market models. The main part of the paper is devoted to a detailed presentation of our new model concept. At the end we also briefly present results from a case study of the Norwegian power market, to illustrate potential use of the model.

2   INVESTMENT DYNAMICS IN THE POWER MARKET

2.1   Decentralised and imperfect decision making

One of the characteristics of the deregulated power market is that many of the decisions that used to be centralised are now made at more decentralised levels in the power system. This is also the case for decisions regarding investments in new power generation. The introduction of competition in the market has shifted the investment focus from meeting demand to maximising profits. Under these circumstances it is no longer certain that installed generation capacity is always ahead of the load development. Power plants have a long lifetime and a substantial fraction of the total costs are paid up front. At the same time there is high uncertainty

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[1] This is not necessarily the situation in recently deregulated power markets, as clearly illustrated by the problems in California.

regarding the future electricity prices. Consequently, investors might be reluctant to invest in new generation capacity in time to meet increasing demand. Delays caused by the time it takes to get construction permits and to construct new plants, also contribute to the likelihood for an imbalance between load and generation capacity.

The expected electricity price is clearly the main feedback signal for investments on the supply side of the market. The demand side, on the other hand, consists of a large number of consumers, and the link between price and investment in end-use technology is less clear. Small consumers, for example single households, do not base their investment decisions on purely economic arguments. Their behaviour is more likely to be described as bounded rationality. It is still reasonable to assume that there is price feedback also to demand, especially to large industry consumers. Moreover, shorter construction delays are also present on the demand side. Certain amounts of investment dynamics are therefore present on both the supply and demand side of the power market. Interventions from regulating authorities, in terms of taxation, subsidies and concession policy, contribute to change these dynamics.

2.2 Traditional modelling approaches

Most traditional long-term planning models for the electricity industry are based on cost optimisation or econometric approaches. These models usually have an underlying assumption of perfect investor foresight, and therefore fail to include the delays and imperfect decision-making that result in the investment dynamics described above. Alternative modelling approaches are therefore needed, but most of the models that are being developed for the new competitive environment seem to focus on shorter-term issues like operation planning, trading and economic risk management. One of the few new power market models that also address the long-term investment effects is documented in [2].

2.3 System dynamics

In our model we use *system dynamics* to model investments in the power system. The theory of system dynamics was developed during the fifties and sixties by Jay W. Forrester as a policy design tool for complex management problems [3]. The theory draws upon control-, organisation-, and decision theory. Mathematically, system dynamics is a set of non-linear differential equations that are solved numerically. The basic building blocks are stocks and flows within a structure of information feedback loops. System dynamics has been used to analyse dynamic patterns in a range of different industry sectors [4]. It has also been used in previous studies to analyse cycles in power plant constructions in England [5] and California [6]. Our model differs from those two approaches by including several generation technologies in the model. We also introduce a limited feedback from price to electricity demand.

3 THE MODEL

3.1 General characteristics

The model simulates the development of the power system within a region for a long period of time (20-50 years). We model the power market with a supply and demand curve, and the electricity price is derived from the intersection of the two curves. The time resolution in the model is one year, using the simplifying assumption that investment decisions are made at the beginning of each year. New investments in generation and demand-side technology result in a change in the supply and demand for electricity. Consequently, we end up with a dynamic description of the supply and demand curve, with price as the main feedback mechanism.

The level of detail in the model is aggregated. Instead of going into details on the different parts of the system, we try to focus on the relationships that we see as most important for the long-term development of the power system. The model is therefore a tool for generating scenarios to analyse what is likely to happen under certain circumstances (e.g. about the development of fuel prices, taxation, technological improvements etc.). To facilitate communication of the model and its results to decision makers we have therefore used Powersim[2] to implement the dynamic description of the supply and demand curves. The price calculation is carried out in Visual Basic with a corresponding Excel spreadsheet interface. The list below shows the main variables and parameters used in the model.

General variables:
$p(t)$ wholesale electricity price [NOK/MWh]
t time [years]

Supply, generation groups, $i \in [1,m]$:
$g_i(t)$ annual generation [TWh/year]
$ncap_i(t)$ new capacity [MW]
$acap_i(t)$ approved capacity [MW]
$\hat{p}_i(t)$ price forecast [NOK/MWh]
$RC_i(t)$ remaining reserves [TWh/year]
$GC_i(t)$ annual generation capacity [TWh/year]
$EIC_i(t)$ energy investment costs [NOK/MWh]
$VC_i(t)$ variable costs [NOK/MWh]
$MC_i(t)$ marginal costs [NOK/MWh]
$OC_i(t)$ operation and maint. costs [NOK/MWh]
$FC_i(t)$ fuel costs [NOK/MWh]
$II_i(t)$ investment incentives [NOK/kW]
$OI_i(t)$ operating incentives [NOK/MWh]
$CF_i(RC_i)$ capacity factor, full load hours [hours/year]
$PF_i(t)$ profitability factor
ir_i internal rate of return
rr_i investors' required rate of return
δ_i deviation in required rate of return

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[2] Software developed specifically for system dynamics, with emphasis on the visual presentation of simulation models.

ic_i	initial capacity investment cost [NOK/kW]
k_i	annual technology improvement factor
n_i	expected lifetime [years]
$amax_i$	max permit applications per year [MW]
ad_i	approval delay [years]
cd_i	construction delay [years]
a_i	approval rate, $a_i \in [0,1]$
$w(u)$	factor used to adjust marginal value of regulated hydropower, $w \in [0.5, 2.5]$
u	stochastic relative inflow, $u \sim N(1, \sigma_u)$

Demand, demand groups, $j \in [1,n]$:

$d_j(t)$	annual load [TWh/year]
$MD_j(t)$	marginal willingness to pay [NOK/MWh]
$DC_j(t)$	max annual demand [TWh/year]
$DTOT(t)$	max total annual demand [TWh/year]
$fp(t)$	flexible fraction of $DTOT(t)$, $fp(t) \in [0,1]$
$tax(t)$	electricity end use tax [NOK/MWh]
dg_{ref}	annual demand growth reference
ε	long-term price elasticity
dd	demand adjustment delay [years]
p_{curt}	curtailment price [NOK/MWh]

Power exchange, import and export groups, $k \in [1,o]$:

$im_k(t)$	annual import [TWh/year]
$ex_k(t)$	annual export [TWh/year]
$IMP_k(t)$	import price [NOK/MWh]
$EXP_k(t)$	export price [NOK/MWh]
$EXC_k(t)$	power exchange capacity [TWh/year]

3.2 Supply side description

Power generation is divided into a number of generation groups, with each group representing one specific technology. The main relationships included in our modelling of investments in new generation capacity follow the same structure for all the generation groups. The causal loop diagram in Figure 1 illustrates this structure.
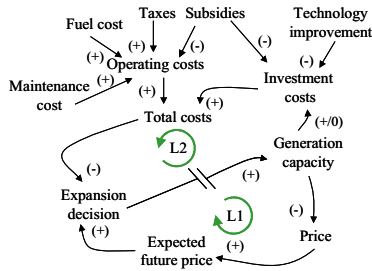

Figure 1: The main factors and relationships influencing on investments in new power supply. The signs on the arrows indicate how the variables are related. L1 and L2 represent feedback loops.

There are two feedback loops in Figure 1. The first feedback loop (L1) states that when generation capacity is increased the price is likely to fall. This lowers expectations of future prices, which in turn reduces the likelihood of future expansion decisions. L1 is therefore a balancing loop that limits the investments in new generation. The second feedback loop (L2) is caused by the connection between current installed capacity and investment costs. The sign and magnitude of this relationship varies for different generation technologies. For renewable technologies like hydropower and wind power we assume that locations with the best energy resources, or the highest expected capacity factor, are utilised first. The investment cost is therefore a function of remaining reserves, which in turn are directly linked to installed capacity. Hence, there is a positive link between installed capacity and investment costs, and L2 becomes a balancing loop for these technologies. On the other hand, fossil-fuelled power plants do not have the same clear link, since there is usually no constraint on the amount of fuel supplied to these plants. The capacity factor is now a function of the dispatch of the power plant, and the change in dispatch due to new installed generation capacity is dependent on the overall power system characteristics. We are treating the capacity factors for thermal technologies as constants in the investment part of the model. As a result, there is currently no link between installed capacity and investment cost for these technologies. However, by including more details in the modelling of the power system operation, we could include this link using simulated capacity factors.

The two bars on the line between expansion decision and generation capacity in Figure 1 represents a delay. An expansion project goes through several stages before it eventually comes on line, as shown in Figure 2. All these stages are represented as aggregation variables in the model. The two main delays are concerned with obtaining a permit to build a new plant and constructing it. These two delays are therefore included in the model to capture the investment dynamics.
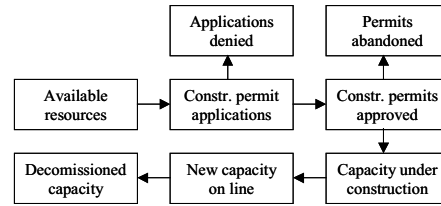
Figure 2: The stages in a power plant's life cycle.

A technology group's total cost is of course one of the main input factors when investments in new generation plants are considered. We therefore need a description of how investment and operating costs are likely to change over time. The investment costs per energy unit (EIC_i) depends on initial investment cost, technology learning, subsidies, expected lifetime and the capacity factor, as shown in equation 1.

$$EIC_i(RC_i, t) = \frac{ic_i \cdot e^{-k_i(t-t_o)} - II_i(t)}{n_i \cdot CF_i(RC_i(t))} \qquad (1)$$

The variable costs of a generation group (VC_i) are the sum of fuel, maintenance and operating costs. The authorities could possibly also impose operational incentives such as subsidies for renewable power generation or CO_2 taxation of generation from fossil fuels. All these elements are exogenous inputs to the model, but can still change as a function of time, as shown in equation 2.

$$VC_i(t) = FC_i(t) + OC_i(t) - OI_i(t) \qquad (2)$$

We assume that investments in new power generation are based on purely economic arguments. Power companies invest in plants if the expected profitability is high enough to cover their required rate of return on capital. The expected profitability is dependent on total costs and the expected future price. We employ a first order exponential smoothing process to forecast the price a specific number of years into the future[3]. The time periods used in the backward-looking trend calculation and the forward-looking extrapolation, can be defined individually for each single technology. It is for instance reasonable to assume that investors in wind power have shorter time horizons for their price forecast than hydropower investors, due to shorter lifetime and construction time.

The values for investment costs, variable costs and expected future price can be used to find the expected internal rate of return on new investments in a generation technology. We do this by setting the net present value to zero, as shown in equation 3. The expected price and variable costs are treated as constants within each time period. Hence, we can derive a profitability factor (equation 4) that is used as an indicator for the quantity of new permit applications and constructions. The factor can be expressed either in terms of expected price and cost figures, or as a function of internal rate of return and lifetime. By using figures for lifetime and required rate of return in the last part of equation 4, we can therefore calculate the required profitability factor for investments in different generation groups. Figure 3 shows how approval applications and new constructions are modelled as a function of this profitability factor.

$$-n_i \cdot CF_i \cdot EIC_i(t) + CF_i \sum_{l=1}^{n_i} \frac{\hat{p}_i(t) - VC_i(t)}{(1 + ir_i)^l} = 0 \quad (3)$$

$$PF_i(t) = \frac{\hat{p}_i(t) - VC_i(t)}{EIC_i(t)} = \frac{n_i}{\sum_{l=1}^{n_i}(1 + ir_i)^{-l}} \qquad (4)$$

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[3] This is a built-in value forecasting function in Powersim.
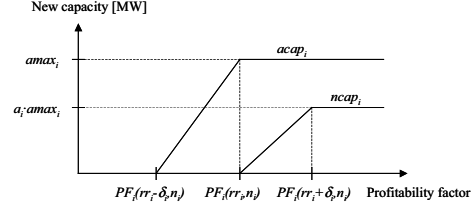

Figure 3: New applications for construction permits ($acap_i$) and new constructions started ($ncap_i$) as function of the profitability factor ($PF_i(t)$).

We assume that a higher profitability factor for a technology i, corresponding to a higher expected rate of return, results in an increase in new applications for construction permits for that technology (Figure 3). The capacity of new constructions started is also an increasing linear function of the profitability factor, but with a less steep slope. There is a limit to the capacity of new permit applications that is equal to an exogenous input factor $amax_i$. A corresponding limit to the capacity of new constructions started is lower, and equals the approval rate (a_i) times $amax_i$. Furthermore, we assume that investors require a higher rate of return to start the construction of new plants than what is required to apply for permits. The required rate of return (rr_i) and its deviation (δ), as shown in Figure 3, should be set to resemble the assumed behaviour of investors in the various power generation technologies. The model allows the use of different rr_i's and δ's for different generation types. Differentiated rate of return requirements can be used in the case that the risk concerned with investing in different technologies varies considerably[4]. The installed generation capacity, GC_i, is updated for each time step. Equation 5 shows how the construction delay is taken into account in the model. The permit approval delay is modelled in the same way. Construction and approval delays can also vary between the generation technologies, resulting in different patterns of investment dynamics for the different generation groups.

$$GC_i(t) = GC_i(t-1) + ncap_i(t - cd_i) \qquad (5)$$

3.3 Demand side description

Our description of the demand curve is more aggregate than the supply curve, and a substantial part of the demand is described by exogenous input parameters. We still try to capture the most important connections between electricity price and demand both in the short and long run. Figure 4 illustrates how demand is treated in the model. The feedback loop states that increasing demand results in increasing end-user prices. This will in turn give incentives for energy savings, and will

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[4] A technology's expected lifetime and the relative proportion of investment costs and operating costs are two of the factors that are likely to influence investors' perceived risk.

contribute to lower the total demand after a time delay (*dd*). L1 is therefore a balancing loop. The dynamic description of total demand is based on [4]. We assume a constant long-term price elasticity of demand, ε. When the simulated end-user price deviates from the reference price, the price elasticity contributes to change the development in total demand away from the underlying reference growth, dg_{ref}.
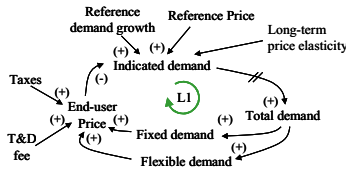

Figure 4: The main relationships on the demand side.

We distinguish between fixed and flexible demand. Flexible demand is defined as the demand that can respond quickly to price signals in the short term without additional investments. Hence, the flexible demand represents the short-term price elasticity in the model. For instance, switching from electricity to oil heating in dual fuelled heat systems represent parts of this flexibility. On the other hand, the fixed demand does not have any substitute in the short run. It still changes in the long run, partly due to the underlying general load growth. Investments in energy saving technology such as heat pumps and improved insulation would also influence the total load development.
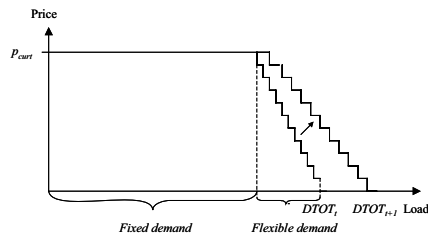

Figure 5: Representations of the demand curve at two different time steps.

Figure 5 shows how the fixed and flexible demand is represented in our description of the electricity market. The total demand, *DTOT(t)*, is updated for each time step, while the fixed and flexible demands follow as fractions of the total demand. The proportion of flexible demand, *fp(t)*, is an input parameter, but can still change as a function of time to describe the expected development of the flexibility on the demand side. Figure 5 illustrates a shift in the demand curve, where the total demand as well as the variable fraction increases. For the fixed demand we assume a fixed curtailment price, p_{curt}. The flexible demand is represented by a number of linear price steps. Hence, the whole demand curve has a linear representation, and can be described by a number

(*n*) of demand groups with corresponding prices (*MD_j*) and capacities (*DC_j*).

3.4 Exchange of power to and from the region

Import of power to the region is handled by adding a number of additional supply steps to the supply curve. Accordingly, a number of export steps is added to the demand function to represent electricity demand outside of the region. The exchange capacity is determined by the capacity of the transmission lines to surrounding regions, and is an exogenous variable that could be set to change over time. The capacity and price of each import and export step should be defined to resemble the power market conditions in the connected regions. The lowest import price must always be higher than the highest export price, to fit into the price calculation as described below.

3.5 Electricity price calculation

The average annual price, *p(t)*, in the wholesale electric power market is calculated for each simulated year. The price is determined by maximising the short-term socio-economic surplus in the market, including imports and exports, as illustrated in Figure 6.
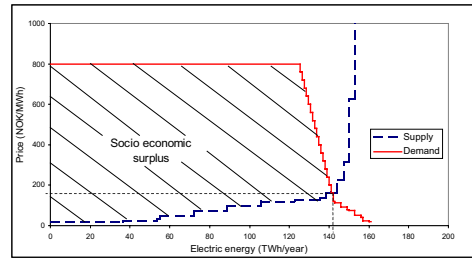

Figure 6: The power market is described by the supply and demand curve for each simulated time step.

The variable costs for the generation groups go directly into the price calculation, where they are treated as marginal costs (i.e. $MC_i = VC_i$), for all generation technologies except regulated hydropower. The regulated hydropower is divided into five separate supply steps, where the marginal value of the most expensive step equals a factor *w* times the lower import price, as shown in equation 6. The marginal values of the other steps are fixed fractions of the most expensive step. This is to take into account that regulated hydropower is dispatchable, and therefore scheduled according to the cost of alternative generation. The alternative generation is usually thermal power, and its marginal costs depend on how much of the system load it has to serve. This is in turn dependent on the annual inflow to hydropower reservoirs. The *w* value is therefore a function of the inflow, *u(t)*, which is drawn from a normal distribution for each time step. The *w* value is low when inflow is high and vice versa. The modelling of the marginal value of hydropower bears resemblance to the so-called water value calculations

that are frequently used in hydropower production planning [7].

$$MC_{hydropower}(t) = w(u(t)) \cdot IMP_{lowest}(t) \qquad (6)$$

Strictly speaking, the shaded area in Figure 6 is not the true socio-economic surplus, due to the use of alternative costs instead of real marginal costs for regulated hydropower. The description still serves as a good approximation of the bidding process in the power market, if we assume perfect competition[5]. The linear description with constant marginal values for each load and generation group is clearly a simplification of the real world. Marginal costs of thermal power plants vary as a function of output for both a single plant as well as for a group of plants. The correctness of the market description is, however, improved by increasing the number of generation groups.

The annual power generation (g_i), consumption (d_j) and exchange (im_k or ex_k) are found directly by applying Visual Basic's built-in algorithm for linear optimisation on the problem below (equation 7-12). All the other variables in the equations are treated as constants in each single optimisation, although they might change between each time step. The electricity price, $p(t)$, occurs as the dual value, or shadow price, of the electricity balance (equation 8). Other figures, like capacity factors, generation costs, consumer's and producer's surplus are easily derived from the results of the optimisation.

$$max \quad \sum_{j=1}^{n} d_j \cdot MD_j - \sum_{i=1}^{m} g_i \cdot MC_i$$
$$+ \sum_{k=1}^{o} (im_k \cdot IMP_k - ex_k \cdot EXP_k) \qquad (7)$$

$$s.t. \quad \sum_{i=1}^{m} d_i - \sum_{j=1}^{n} g_j + \sum_{k=1}^{o} (im_k - ex_k) = 0 \qquad (8)$$

$$g_i \le GC_i, \quad i = 1..m \qquad (9)$$

$$d_j \le DC_j, \quad j = 1..n \qquad (10)$$

$$im_k, ex_k \le EXC_k, \quad k = 1..o \qquad (11)$$

$$g_i, d_j, im_k, ex_k \ge 0 \quad \forall \quad i, j, k \qquad (12)$$

The model is, in its current form, an energy model, and does not address problems concerning peak demand and capacity deficits. Transmission losses and reserve margin requirements are assumed to be included in the demand groups. Consequently, there is one single electricity price for the overall region, so that price differences within the region due to transmission

congestion is not taken into account. The aggregate annual price calculation in the model is motivated from the observation that it is the average electricity price over the year that is relevant for most of the investments we consider, both on the supply and demand side in the power system. However, a more detailed market description could easily be implemented within the current framework, for analysis of effects that requires shorter time resolution, as for instance investments in peak power plants.

4   NORWEGIAN CASE STUDY

We developed an input dataset for the Norwegian power market based on information in [8] and [9]. The most important input figures are shown in the appendix. On the supply side we have added the 4 generation technologies that currently seems to be most relevant in Norway (hydro-, wind-, gas- and gas power with CO_2-capturing). The demand side is described by a few key variables. We first run a business as usual scenario (reference), where we assume that the authorities take a passive approach and leave the market to decide on the timing and technology for new generation. In the second scenario (green) we assume that the authorities introduce CO_2 taxation of 125 NOK/ton[6] from 2002, and that they also show preferences for renewable power generation when giving construction permits. In both scenarios we assume constant average inflow to the hydro reservoirs.
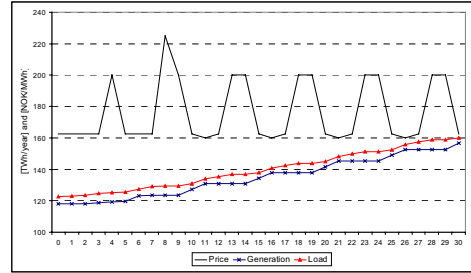
Figure 7: Simulated electricity price, generation and load in the reference scenario, 2000-2030.
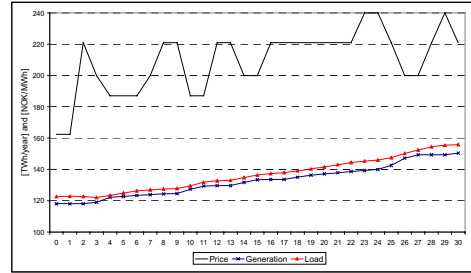
Figure 8: Simulated electricity price, generation and load in the green scenario, 2000-2030.

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[5] Modelling of imperfect competition and strategic bidding is more relevant for shorter time horizons where peaking effects from daily and seasonal load variations are included. We assume that these effects make a negligible impact on the average annual electricity price.

[6] This corresponds to $14/ton with current exchange rate.

Figure 7 shows that the simulated price fluctuates throughout the 30 years in the reference scenario. Capacity expansions are triggered during the high price periods, but delays cause the expansions to lag behind the price development. Most of the expansions are in large-scale gas power, as shown in Figure 9. The load also responds to the price and shows a similar fluctuating pattern, due to short- and long-term price elasticity. In the green scenario the price increases immediately after the CO_2-tax is introduced in 2002 (Figure 8). The price also fluctuates here, but at a higher price level and with less regularity than in the reference scenario. The generation development is smoother because of a larger degree of small-scale renewable generation technologies (Figure 9). The demand shows a similar trend as in the reference scenario, but with lower growth, especially after the price increase following the CO_2-tax. The generation is always lower than load in both scenarios, since we assume excess import capacity throughout the period.
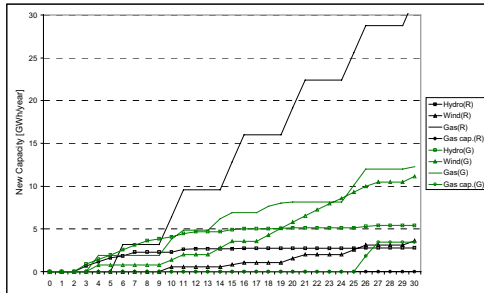

Figure 9: Simulated new generation capacity in the two scenarios (Reference-R/Green-G), 2000-2030.

We only show a limited number of results here, as our main focus in this article is on the presentation of the model. However, by changing the input variables it is possible to study different topics, ranging from natural effects like stochastic inflow to effects from authority regulations, like subsidies of certain generation technologies or changes in end-use taxation.

5 CONCLUSION

In this paper we have presented a new model for long-term analysis of deregulated power markets. The results from the Norwegian case study shows that the model is able to capture parts of the long-term dynamics that is likely to occur on both the supply and demand side of the power market. We argue that the liberalisation of power markets has increased the importance of incorporating these effects into long-term planning. The model concept could be extended in several directions. Shorter time steps and more detail in the price calculation would make the model suitable for analysis of short-term effects like peak demand problems. Moreover, a stochastic price description would make it easier to better take into account the risk preferences of investors in the power market. At last,

inclusion of several load sectors could improve the representation of demand in the model.

APPENDIX

The following tables contain the main input data for the simulations of the Norwegian power market:

	Hydro	Wind	Gas	Gas cap[1]
RC_i	30	80	100	100
OC_i	20	35	25	40
FC_i	0	0	100	120
OI_i[2,3]	0	0	0/-45	0
II_i	0	0	0	0
CF_i	$CF_i(RC_i)$	$CF_i(RC_i)$	8000	8000
ic_i	5000	8000	6000	10000
k_i	0.002	0.014	0.005	0.012
n_i	40	20	30	30
rr_i	0.07	0.07	0.07	0.07
δ_i	0.02	0.02	0.02	0.02
ad_i	3	2	3	3
cd_i	3	1	2	3
a_i[2]	0.5/0.7	0.5/0.7	0.5/0.3	0.5/0.3

Table A1: Input parameter values for the generation side. [1]Gas power with CO_2-capturing. [2]Values for the two scenarios ref/green. [3]CO_2 tax introduced in 2002 for Gas power.

dg_{ref}	p_{curt}	ε	dd	fp	tax
0.01	800	-0.31	2	0.14	100

Table A2: Input parameter values for the demand side.

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Paper 8

Effects of large scale wind production on the Nordic electricity market

Proceedings from European Wind Energy Conference 2001, 2-6 July, Copenhagen, Denmark.

1

EFFECTS OF LARGE SCALE WIND PRODUCTION ON THE NORDIC ELECTRICITY MARKET

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ABSTRACT: Simulations with the power market model EMPS with weekly time resolution have been made to assess the effects of large scale wind production to the Nordic electricity market. Two base case scenarios are made (reference for the Nordic market area for years 2000 and 2010) and wind is added to these systems in 3 steps. The results for the simulations with 16…46 TWh/a wind production in Nordic countries (4…12 % of electricity consumption), show that wind power replaces mostly coal condense and oil as fuel for electric boilers. As a result of fuels replaced by wind production a CO_2 reduction is achieved, of 680…620 gCO_2/kWh. Indications for bottlenecks in transmission can be seen, especially to Central Europe, when the wind production is above 20 TWh/a. Average spot market price drops by roughly 0.2 eurocents per 10 TWh/a wind production added to the system. Avoided costs for wind power production are roughly 2 eurocents/kWh for today's system and 3.1 eurocents/kWh for 2010 system with CO_2 tax and reduced power surplus. Changes in socio-economic surplus for the market is 2.4…2.0 eurocents/kWh for 16…46 TWh/a wind production, i.e.15 % higher than average spot price (for 2010, 3.9 eurocents/kWh, 30 % higher than average spot price).
Keywords: Electrical Systems, Markets, Emissions, Simulations, Electricity market

1 INTRODUCTION

In the Nordic countries, the electricity system is characterised by large share of hydro power. The deregulated electricity market in the countries has led to the joint electricity market Nordpool. Wind power is still marginal in the system today (4 TWh/a) but national targets are existing for 16 TWh/a in 2010 (Denmark 8, Sweden 4, Norway 3, Finland 1 TWh/a), and considerably more in 2030.

The purpose of the paper is to study the influence of large amounts of wind production to the market: differences between the spot prices, power transmission between the countries, production of hydro and thermal power, with and without wind power. This is done by running simulations on the EFI's Multi-Area Power Market Simulator (EMPS) model, a commercial model developed at SINTEF Energy Research in Norway for hydro scheduling and market price forecasting [1].

2 POWER MARKET MODEL EMPS

2.1 Description of the model

The power market model EMPS simulates the whole of the joint market area, instead of only one country. The market is divided into areas with transmission capacities between the areas (Fig 1). The model description used here is most detailed for Norway, which is modeled as 12 areas. Finland is modeled as one area, Sweden and Denmark as two areas. Central Europe is modeled as one big area (Germany and the Netherlands) and treated like a large buffer with which the Nordic system has transmission possibilities.

The model simulates the market price and the production for each area with weekly time resolution. The simulation is here made for one year. Historical inflow and wind data from 30 years are used as input for the simulation to take into account the stochastic nature of inflow and wind.

The model has a good description of the Nordic hydro power system to be able to take into account the large variations in hydro inflow compensated by large storage reservoir capacities.
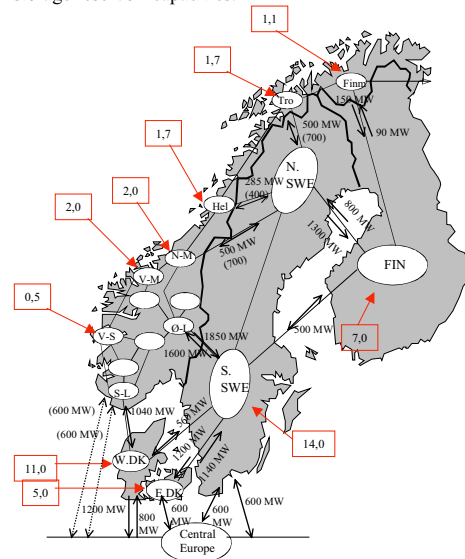

Figure 1: Areas, transmission capacities between the countries (scenario 2010 figures in parenthesis) and wind3 amounts of wind production (TWh/a) in the EMPS model.

Thermal capacity in the Nordic countries is simulated in less detail than the hydro system. Because only weekly resolution is used, no restrictions or costs of regulation or start-ups of the thermal capacity are taken into account. The model assumes that in-week variations are handled by the large hydro reservoirs in the system.

The model optimises the use of hydro power by calculating water values to the amount of water in the reservoirs, by stochastic dynamic programming algorithm. These water values vary both by the time of

year and by the current and anticipated water inflow to the reservoirs. They are treated as the marginal cost of hydro power [2]. With a price to each production capacity known, the market price is determined by a market cross (Fig 2). This is done for each simulated week. If transmission capacity is restricted, there will be different prices in different areas.
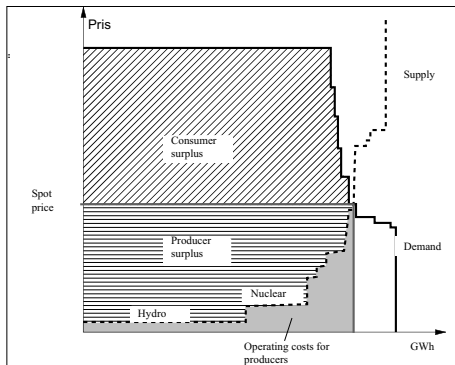

Figure 2: Market cross: the spot price calculation in the power market simulation model EMPS.

2.2 Input for the model. Reference cases.

Input data needed for each area are weekly consumption, operating costs for thermal power, maximum production (or capacity) for thermal power, detailed description for hydro power system, inflow data and transmission capacities between the areas.

The input for thermal power prices are operating costs. This is because we are simulating the bidding process in the market. In the market the producer gets the price determined by the market cross (fig.1), thus it is cost-effective for him to produce as long as the price he gets is higher than his/her variable costs. Wind energy is a price taker in the market, all that is produced will be sold, no matter what price. The marginal price is therefore 0 Euro/MWh for wind, when operating without storage, like it is for run-of-river hydro plants.

The capacities for transmission lines are shown in Fig. 2. Between Norway and Sweden lower limits for the lines than in [3] are used to take into account the technical restrictions in transmission. The production capacity is shown in table 1 for both the 2000 and 2010 base case. The thermal capacity is given either as maximum capacity [MW] or maximum weekly production [GWh]. The electricity consumption contains price elastic use of electricity mainly in Norway and Sweden. This is provided by electric boilers, which can switch from burning oil to using electricity, and also industrial consumption in Norway. Four load duration levels are used to take into account the consumption pattern inside a week.

In the scenario made for year 2010 [4] electric consumption was added by 32.2 TWh/a and production capacities were changed. For Sweden one nuclear plant was shut down, condense was shifted to biofuels and CHP was added. For Finland more CHP and coal was added [5]. For Norway a new gas power plant (400 MW) was added. For Denmark coal was shifted towards gas [6]. Improved transmission capacity was foreseen for Norway/Central Europe and between Norway and

Sweden (fig.2). CO_2 tax of 15.6 Euro/tCO_2 (125 NOK/tCO_2) was added to operating costs of fossil fuels. The effect of CO_2 tax is to rise the marginal costs: for coal by roughly 12.5 and gas by 7.5 Euro/MWh. Thermal power costs in Central Europe were adjusted closer to those in Denmark and Finland to reach a balance in the market. As a result, the thermal production was up 25.4 TWh/a and price elastic consumption down 5.7 TWh/a.

Table 1: Maximum production capacity and electricity consumption as input to the EMPS model (ref2000 plain **ref2010 bold**). CHP= Combined heat and power.

	Fin	**Swe**	**Den**	**Nor**	**Eur**
Consumption	78800	142400	34900	120000	567100
[GWh/a]	**90500**	**152300**	**37000**	**121900**	
Nuclear	21800	70800			152900
[GWh/a]		**67000**			
CHP	24800	8700	27000		196600
[GWh/a]	**28600**	**15000**	**44000**		
Condense	3000	400	1800	280	42500
[MW]	**4000**	**1200**		**680**	
Gas turbines [MW]	975	195	70		
Hydro* [GWh/a]	13000	63000	3500*	115000	

*wind in DK

3 WIND PRODUCTION DISTRIBUTED IN NORDEL AREA

Wind power was added to the system in 3 phases, cases wind1…wind3, starting from 16 TWh/a (wind1) to reach 46 TWh/a (wind3) annual total production in the Nordic countries. This corresponds to 4…12 % of total electricity consumption and it is divided between the countries as 20…45 % of consumption in Denmark and 2…10 % of consumption in Sweden, Norway and Finland. Wind1 corresponds to existing targets for 2010 and wind3 is near possible targets for 2030.

Table 2: Wind power added to the system. Production in TWh/a and as % of electricity consumption today in the simulated cases.

	Wind1		Wind2		Wind3	
	TWh/a	%	TWh/a	%	TWh/a	%
Norway	3	2.5	6	5.0	9	7.5
Sweden	4	2.8	9	6.3	14	9.9
Finland	1	1.3	4	5.1	7	8.9
Denmark	8	22.9	12	34.3	16	45.7
TOTAL	16	4.3	31	8.2	46	12.2

4 WIND DATA

To catch the effect of varying wind resource, wind production was acquired from the same time period as the hydrological input data, years 1961–90. Weekly wind production was calculated from wind measurement data. Measured wind speed was converted to power

according to power curve of 1.65 or 2 MW wind turbines [7].

In Norway, wind power was added to 6 areas, based on 3 wind measurement data points in Middle and North Norway (table 3). Wind power was added to South-Sweden based on 3 wind measurement data points in Gotland and Southern Sweden. Wind power was added to both areas in Denmark, some more to West Denmark than to East Denmark. From Denmark only one measured wind speed series was available. The East Denmark production was based on South Sweden wind data, near the Danish coast.

Table 3: Weekly wind production data used as an input for the power market model.

Wind data from	Full-load hours, average	TWh/a in wind3	Weekly production, average = 100 %	
			Max	Min
Helnes, NOR	3000	1.1	158	0
Bodø, NOR	3000	3.4	171	0
Ørland, NOR	3000	4.5	196	3
Visby, SWE	2600	5.0	293	7
Säve, SWE	2600	3.0	306	0
Barkåkra, SWE	2600	11.0	298	0
Valassaaret, FIN	2200	7.0	247	2
Risø, DK	3200	11.0	262	3
TOTAL wind	**2700**	**46.0**	**221**	**14**

Large scale wind production would in reality mean production from many, scattered wind parks. Using data for few, single measurement points will overestimate the variations of wind production in a large area. As we are using weekly averages, however, this overestimation is not as profound as it would be f.ex. in hourly data.

Correlation coefficients between the weekly production series of different wind production sites were 0.11…0.76. Wind production is correlated inside Norway and Sweden, and between East Denmark and Southern Sweden. Wind production is only weakly correlated between the countries. The lowest correlation coefficients were between Southern Sweden and Northern Norway.

5 RESULTS OF THE SIMULATIONS

5.1 Effects on the energy balance between the countries

As wind production is added as extra production to the electricity system, about 30 % of the wind production is transferred out of the Nordic countries with the transmission lines to Germany, Poland and the Netherlands (in 2010 scenario about 40 %).

In Finland wind production replaces condense production (mainly coal). Import to Finland increases. For wet years in the wind3 case the nuclear production is also reduced. In Sweden the electricity consumption in electric boilers is increased with increased wind production. This means that wind production is replacing oil (alternative fuel for the boilers). Wind production is replacing condense production, for the little there is to replace, and some of the nuclear and CHP production. Export of electricity is increased substantially. In Norway the consumption in electric boilers increases

with added wind production. Export is also increased. In Denmark wind is replacing condense (mainly coal) and increasing export. Both imports and exports in Denmark are increasing with increasing wind in the system.

For the cases wind2 and wind3 there are indications of bottlenecks in transmission in all lines to Central Europe, especially from West Denmark to Germany. Between Norway and Denmark, Norway and Sweden, and within Norway added wind production helps out the situation during dry years but makes some bottlenecks during wet years more profound (these lines have bottlenecks already in the reference cases). Between Sweden and Finland and inside Sweden even a large-scale wind production does not make a substantial increase in the use of transmission lines compared to the reference. However, more detailed time resolution would be neede to conclude on the issue. High wind production in Northern Norway makes a bottleneck to the minor transmission line between North Norway and Finland.

5.2 CO_2 emission reduction

Wind production results in different fuels being replaced in the system. As a combined result of this replacement a CO_2 reduction is achieved. This varies between 680 and 620 gCO_2/kWh in wind1 and wind3 cases respectively. For the 2010 scenario the CO_2 reduction is slightly larger. For comparison, coal, oil and gas fired units emit approximately 800, 650 and 430 gCO_2/kWh respectively.

5.3 Effect on market prices

Simulated spot price for an average inflow situation in the electricity market is about 2.3 eurocents/kWh for today's system. It rises to 3.5 eurocents/kWh for the 2010 scenario due to a CO_2 tax. and reduced power surplus (more consumption than production capacity added)

Wind production is seen as extra production in the system with zero marginal price, causing the spot prices on the market to decrease, about 0.2 eurocents/kWh per each 10 TWh/a added wind production (ref2010), little less in ref2000 cases (Fig3). Decrease in spot market price has to do with adding wind power in the market as an extra production. Results of simulations when thermal capacity was decreased while adding wind show only a moderate price decrease (about 0.2 eurocents/kWh per 40 TWh/a added wind production).

5.4 Value of wind energy

The market value of wind energy is the spot market price for the wind production. According to the simulations made here, wind production would be priced on an average about 2 % higher than the spot price. This means that the high price weeks would be slightly more windy than the low price weeks. With large scale wind production in the system (case wind3) this price difference would reduce to about 1 %. Denmark is an exception to this: wind production would be priced 1-2 % lower than the average spot price. Prediction errors in wind production would result in wind producers getting a lower price, when part of the production would be sold in the balance market.

One way of estimating the value of wind energy to the production system is to calculate the avoided costs of thermal power when using wind power. These are the operating costs (mainly fuel costs) of thermal power as well as the fuel saved in electric boilers. The difference

in the operating costs of thermal power and electric boilers between the reference case and the wind cases give the avoided costs. For the 2000 system cases the avoided costs by wind power are 2.1 eurocents/kWh in case wind1 decreasing to 2.0 eurocents/kWh in wind3. For the 2010 scenario the avoided costs by wind power are considerably higher than for today's system, because of the CO_2-tax added to fuel cost as well as reduced power surplus: 3.3…3.1 eurocents/kWh (Fig.3).

Another way of estimating the value of wind energy to the system is to calculate the the socio-economic surplus (sum of consumer and producer surplus, Fig 2). When looking at the differences in the socio-economic surplus between reference and wind cases, we get the value of wind to the whole market. For the 2000 system cases this is 2.4 eurocents/kWh decreasing to 2.0 eurocents/kWh with large scale wind production. For 2010 scenario the total value of wind production to the system is 4.4…3.9 eurocents/kWh respectively (Fig. 3).
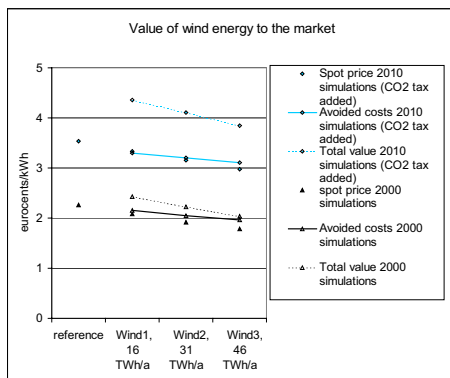

Figure 3: Avoided costs and socio-economic surplus (total value) when comparing the wind cases to the reference cases. For comparison, the average spot price (South-Norway) is shown. (All prices for an average hydro inflow.)

6 CONCLUSIONS AND DISCUSSION

The Nordic electricity market has been simulated with and without wind production to assess the effects of large scale wind production on the market. Results of weekly electricity flow and prices in the market area for different hydrological years can be obtained from the EMPS power market simulation model output.

Wind power replaces mostly coal condense and oil as fuel for electric boilers. For large amounts of wind power, 8-12% of consumption, also nuclear production is slightly reduced during wet years. Reductions do not occur in the same countries as the wind production, f.ex. coal condense is replaced also in Central Europe. As a result of adding wind to the simulated system, CO_2 emissions will be reduced 680…620 gCO_2/kWh.

Indications for bottlenecks in transmission can be seen, especially to Central Europe, when wind production is above 8 % of the electricity consumption.

Large amounts of wind production in the market will lower the spot price, when wind production comes as an extra production to the system. Average spot market price drops by roughly 0.2 eurocents per 10 TWh/a wind

production added to the system. Wind power would get on the average 1-2 % higher price than the spot price, if no prediction error is taken into account. Comparing the market spot prices with total production costs for wind power, it is clear that today's market price would not be enough to initiate investments in wind power, where as market prices as a result of our scenario for 2010 would make the best wind resource sites cost-effective.

Avoided costs for wind power production are 2.0…2.1 eurocents/kWh when adding wind production to today's system, slightly higher than average spot price. This is not taking into account any environmental benefits of wind production. CO_2 tax added to fuels of conventional power brings an environmental bonus to wind power in the 2010 figures, where the avoided costs would be 3.1…3.3 eurocents/kWh. The avoided costs give the value of wind to the total production system, as the reduced operational costs for electricity production.

The socio-economic surplus to the electricity system takes into account both the consumer and producer sides of the market. The socio-economic value of wind energy for the system is 15 % higher than average spot price for today's system and 30 % higher than the average spot price for the 2010 scenario with CO_2 tax and reduced power surplus in the system (more consumption than production added). The socio-economic value is what a market regulator would look into, when analysing whether wind production would be beneficial for the system, and how much wind could be subsidised from the market point of view.

These conclusions are made from simulations assuming that all the large scale wind production will be available in the system. This means that grid connection as well as the hourly variations of wind would be taken care of. Weekly and hourly scheduling of thermal and hydro power with large wind production share will be questions for further study.

ACKNOWLEDGEMENTS

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Paper 10

System benefits of coordinating wind power and hydro power in a deregulated market

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System benefits of coordinating wind power and hydropower in a deregulated market

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ABSTRACT: New additions of wind energy in the Nordic electricity market has been studied using the EMPS model. A scenario for year 2010 with CO2-tax and a total of 16 TWh of wind energy according to national targets have been included. The study focuses on the effect of changes in production scheduling imposed by new additions of wind energy under operation of a deregulated market. As a result, the import/export balance between the countries change in favor of exports to Finland and Germany. CO2-reductions caused by wind energy is estimated to be 540 tC/GWh of wind energy generated for the 2010 scenario. The main CO2-reductions take place in Germany and Finland as the result of wind energy expansion in Norway, Sweden and Denmark. The energy value of wind power of the Nordic hydro-thermal deregulated market is estimated to be 7% higher than the average spot price in the 2010 scenario.

Keywords: Markets - 1;Power Plant Scheduling - 2; Environmental Aspects - 3

1. INTRODUCTION

There are extensive plans for realising the potential of wind power in the Nordic countries. The government in Norway recently set a target of 3 TWh within 2010 [1]. In Sweden, the wind power production will probably yield 4 TWh in 2010 [2], and in Denmark 17 TWh in 2030. In Finland the target is 1 TWh production from wind power in 2010 [3].

In the Nordic countries, electricity is traded between the countries in an open, liberalised, joint market. Thus system integration of wind energy not only influence domestic energy production, it influences the whole market area. However, energy and environmental policies are usually made on national level.

In the Nordic countries, the electricity system is characterised by its large share of hydropower, especially in Norway and Sweden. The large variations in hydro inflow are compensated with large storage capacities, giving a large flexibility in hydropower scheduling.

The purpose of this paper is to explore the changes imposed by expansion of wind energy in the Nordic market area. Wind power influence area prices which in turn influence production scheduling, and thereby total CO2-emissions for each of the Nordic countries uncorrelated with the location of new wind energy. The simulations are carried out using the EMPS model, a stochastic model for long-term optimisation and simulation of hydro-thermal system operation.

2. THE EMPS MODEL

The EMPS model (EFI's Multi-area Power-Market Simulator) was originally developed for hydro scheduling purposes [6]. After deregulation, it has also served as a tool for price forecasting. In brief, the model optimises the total electricity production for a set of interconnected areas, including several types of electricity production. The EMPS model has two main parts. In *the strategy part*, the so-called water values of the water reservoirs are calculated using a SDP (stochastic dynamic programming) algorithm on aggregated reservoir representations of each area. The water values are estimates of the future value of water in

the reservoir for given reservoir levels. They are functions of expected future inflow and alternative production costs (e.g. from thermal power production), and in the EMPS model they are treated as the marginal cost of hydro power.
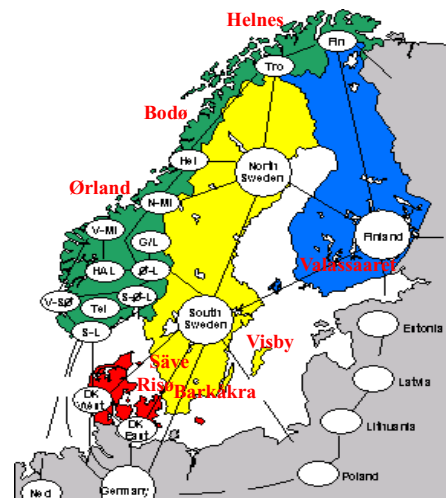

Figure 1 The EMPS model of interconnected areas with capacity constraints that limits exchange between areas. Location of the seven selected met stations for wind energy modelling are also indicated in red.

The calculated water values are used in *the simulation part*, where the optimal hydropower schedule with respect to maximised expected profit for each area is determined. The corresponding market prices for each area are also calculated. A more detailed description of the EMPS model is given in [6][7].

3. WIND POWER IN THE EMPS MODEL

3.1 Weekly wind power production data

The weekly wind power production data was based on meteorological wind speed measurements from the years 1961-90. The Norwegian data is from; Ørland, Bodø and Helnes [8]. The Swedish data is from Säve,Visby and Barkåkra [10]. The Finnish data is from Valassaaret, near Vasa. Data from the Risø mast were given to us by courtesy
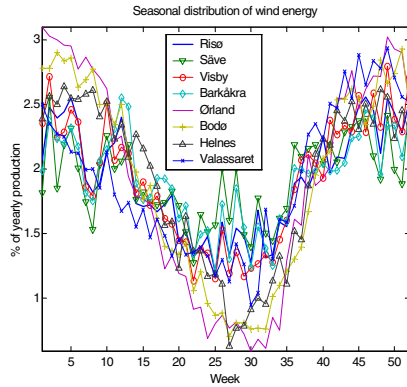

Figure 2 Seasonal variation of wind energy production for the selected 8 met stations. The values are 30-year mean values from 1961-90.

of Risø National Laboratory.

3.2 Wind power modelling

The EMPS model simulates the electricity market with weekly resolution, thus short term fluctuations of wind power is not considered in this study. Wind series have been converted into energy series as described in [8]. The number of full-load hours were set to 3000 for Norway, 2600 for Denmark and Sweden, and 2300 for Finland. Power curve from a 1.5 MW turbine was used for converting wind series in Norway, and data from a 2 MW turbine for the Swedish, Danish and Finnish wind series.

Figure 3 shows how market changes power scheduling with wind power. Wind power is introduced as a base load in the supply curve for *wind2010*, shifting the supply curve to the right. The changes in spot price, Δp and demand, ΔD are marked on figure 3. The area between the *ref2010* and *wind2010* (A1,A2,A3) represents the avoided energy costs due to wind power. For the regulated hydropower units, water values are used for production scheduling. The curved line on the supply curve represents the water value of regulated hydropower. Note that the water values may change after introducing wind energy in the *wind2010* supply curve. Water values are recalculated, because new sources of energy may give another optimal schedule for hydropower. A detailed study on this topic can be found in [9]

The resulting simulated prices are shown as distributions in figure 4, because hydro inflow and wind are stochastic variables.

4. SCENARIOS

Three scenarios were developed for the EMPS model. One for 1999, as a reference, and two for the year 2010.The projections for demand in the Nordic countries are according to [12] and [13]. These reports together with Nordel projections [14] were also used for projections in capacity
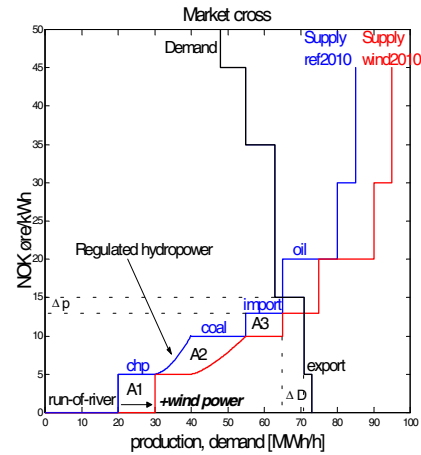

Figure 3 Example of price formation in a particular week, in one of the areas in the EMPS model. Wind power is introduced as a base load, shifting the supply curve to the right.
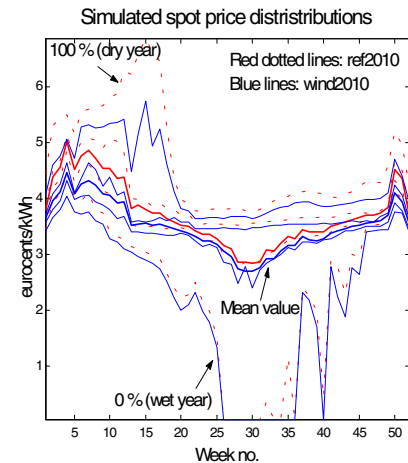

Figure 4 Spot price distributions for the *ref2010* and *wind2010* scenarios. Thick lines show mean values, thin lines show 100 (upper bound), 75, 25 and 0% (lower bound) percentiles for spot prices.

for year 2010 A summary of production capacity data and demand for each scenario is provided in appendix. Production data for Germany is the same in the 2010 scenarios as for the 1999 scenario. We justify this simplification by assuming that the capacity of the remaining fossil fuelled units in year 2010 in Germany are larger than the import/ export capacity to the Nordic countries.

The data set used in this analysis contains 18 areas comprising Norway, Sweden, Finland, Denmark and Germany (see figure 1). Time resolution is one week, and the hydro inflow data is based on the period 1961 – 1990 with weekly inflow data for each existing hydrological unit.

4.1 Reference scenario 1999, *ref1999*

This scenario describes the present installed capacity and demand in the Nordic market area. See appendix for further details of installed production capacity for the different countries.

4.2 Reference scenario 2010, *ref2010*

In Denmark, conversion from coal to gas, plus extensive use of straw and other renewables in CHP district heating according to the *Energy 21* action plan [4] takes place. Though new additions of wind power also are included in these plans, we do not add new wind energy in this scenario. This means that for ref2010, the present yearly wind energy production of 3.5[1] TWh is used. Of course, a scenario without new wind energy in Denmark is unrealistic, but the *ref2010* is used to observe the impact of wind energy, as a reference for the *wind2010* scenario.

In Sweden, 4 TWh of nuclear energy is decommissioned, while the use of gas and renewable CHP generation is intensified. The consumption increases from 143 to 152 TWh/y. In Finland, consumption increases from 73 to 85 TWh/y due to industrial growth. A new nuclear unit producing 10 TWh/y is commissioned, in addition to some new gas fired units. For Norway, a 600 MW transmission line to Germany is expected to be commissioned, and 400 MW of gas power is added. The consumption level has increased by 3 TWh.

A CO_2-tax on electricity generation has been introduced for all of the countries, amounting to 15.6 euro/tC. The choice of this tax level was taken from [5]. The CO_2-tax also applies to Germany.

4.3 Wind scenario 2010, *wind2010*

In this scenario, a total of 12.5 TWh of wind energy is added to the *ref2010* scenario. 3 TWh in Norway according to [3], 4 TWh in Sweden [1], 1 TWh in Finland [4] and 4.5 TWh in Denmark, giving a total of 8 TWh in Denmark and 16 TWh in the Nordic market area as a whole. The only difference between *ref2010* and *wind2010* is the addition of new wind energy.

5. SIMULATION RESULTS

5.1 Energy value

The energy value from wind energy for thermal dominated systems is usually estimated as the avoided costs of energy when wind power is introduced. In a deregulated market, this will be the sum of area A1, A2, A3 in figure 3. The avoided costs are the reduced production costs from the various thermal units substituted by wind energy.

Simulated spot price

Scenario	Nor	Swe	Den	Fin
ref1999[a]	2.3	2.2	2.1	2.1
ref2010	3.7	3.8	3.4	3.6
wind2010	3.5	3.6	3.3	3.5

Table 1: Average spot prices in euro cents (2000) for a year with normal hydro inflow. (1 euro=8 NOK 2000)

a. Note that spot prices are given as mean values for realisations of 30 years of wind- and hydrological inflow data For comparison, the spot price in the Nordic market is currently 1.25 euro cents/kWh (Sept., 2000), because year 2000 has been a typical wet year.

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1. 3.5 TWh corresponds to approximately 1750 MW of wind power when a year of "normal" wind conditions in Denmark is used.

The avoided costs of the 12.5 TWh of wind energy added were estimated to 3.6 euro cents/kWh. This value is approximately 7% higher than the simulated average spot prices for the *wind2010* scenario.

5.2 Export/import balances

Comparing *ref2010* and *wind2010*, Norway increase its export with wind power. There are few thermal units that will reduce its production. However, some dispatch able loads (oil/electric boilers) will increase the consumption of electricity because of the drop in spot prices. Norway, Sweden and Denmark increase their export to Germany both through direct transmission lines and via Denmark. The
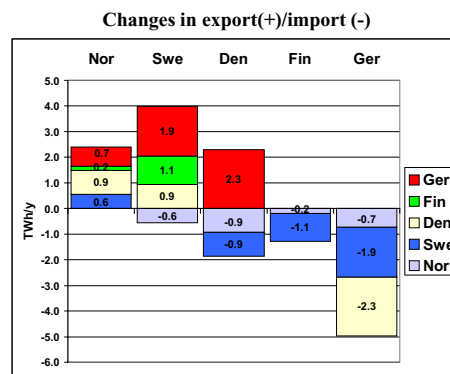
Changes in export(+)/import (-)

Figure 5 Changes in export/import due to wind energy. Export (+) and import (-) are changes between ref2010 and wind2010 scenarios, that is the resulting changes caused by wind energy. Export and import changes are also subdivided into export/import to the different countries, i.e. Sweden increase imports from Norway by 0.6, while export to Germany, Finland and Denmark is increased by 1.9, 1.1 and 0.9 TWh respectively

export to Finland is also increased. To conclude, the increased amount of wind energy in *wind2010* mainly replace production from thermal units in Finland and Germany as a result of price changes between the different areas in the EMPS model.

5.3 CO_2-reductions

A comparison between *ref2010* and *wind2010* shows that wind power helps reducing CO_2-emissions in total. But increasing the share of renewables does not necessarily reduce national emissions, if the utilities are allowed to operate in the liberalised market. From an environmental point of view, the location of CO_2-reductions are unimportant. But for making efficient environmental policies on a national level, these facts should be considered. Figure 6 shows CO_2-emissions for each scenario. For Germany, negative numbers show CO_2-reductions due to export from the Nordic countries relative to the *ref1999* scenario. The big difference between ref1999 and the 2010-scenarios shows the effect of the CO_2-tax, the conversion from coal to gas according to Energy 21 action plan, and the extended use of CHP plants using renewables and gas in Denmark and Sweden as described in section 4.2. The difference between *ref2010* and *wind2010* shows that CO_2-reductions are mainly obtained in Germany and Finland by 4.3 and 1.7 MtC/y respectively. Smaller reductions in Sweden and Denmark are obtained. In total 12.5 TWh of wind energy in 2010 reduce the CO_2-emissions by 6.8 Mt, which gives
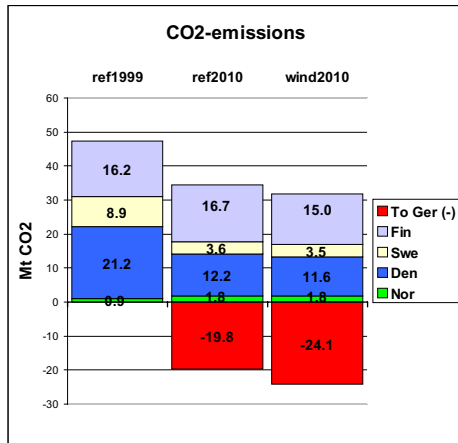
Figure 6 CO2-emissions in absolute values for Norway, Sweden, Denmark and Finland. For Germany, the values are reductions relative to *ref1999* due to imports from the Nordic countries

an average reduction of 540 tC/GWh of wind energy. For comparison, coal, oil and gas fired units emit approximately 800, 650 and 430 tC/GWh respectively.

6. DISCUSSION

In the EMPS model, the operation of units are scheduled using marginal production costs, with constrains on heat production. In practice, utilities may schedule their units differently due to other constraints and considerations. Firstly, information on marginal costs are estimates, because marginal production costs are confidential. Secondly, other constraints may change the merit order of units, for instance, take-or-pay contracts on gas reduces the utility's flexibility of production.

The linear description of transmission capacity between areas underestimate marginal grid losses. The *Samlast* simulation tool add load flow calculations to the EMPS model, and experience from this tool shows that hydropower scheduling will be changed significantly.

When studying the effect of small (marginal) additions of new wind energy, these uncertainties severely influence the results, but they become less important with larger additions of wind energy. We added 12.5 of wind energy in the Nordic market area, which is considered as a minimum for obtaining reliable results. However, the results does show the principal mechanism that are into play when new sources of production are introduced.

7. CONCLUSION

The energy value (cost avoidance) of wind energy was for the *wind2010* scenario estimated to 3.6 euro cents/kWh, approximately 7% higher value than the average spot price that scenario.

Market coordination of power scheduling makes it difficult to trace marginal changes in production. It was shown that adding 12.5 TWh of wind energy in 2010 changes the export/import balance between the nordic countries in favor of exports to Finland and Germany. CO2-emissions were in total reduced by 6.8 Mt, mainly in Germany and Finland resulting from 3, 4.5, 4 and 1 TWh of new wind

energy in Norway, Denmark, Sweden and Finland respectively. On average, wind energy replace 540 tC/GWh of energy produced.

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10. APPENDIX

Supply	Nor	Swe	Den	Fin
		ref1999 (plain)		
		ref2010 (bold)		
Hydro [TWh]	115	63		14.5
Wind Power [TWh]	-	-	3.5	-
	-	-	**3.5**	-
Nuclear,		9450		2610
[MW]		**8850**		**3810**
CHP central		1280	4800	2500
[MW]		**570**	**5220**	**2750**
CHP district		980	2100	730
[MW]		**1916**	**1590**	**2100**
CHP ind		840		1550
[MW]		**820**		**1750**
Condense	0	435	2400	3760
[MW]	**400**	-	**0**	
Gas turb. [MW]		195	70	1450
Demand [TWh]	120	143	34	73
	123	**152**	**37**	**85**

Table 2: Summary of consumption and production data in the EMPS model for ref1999 and ref2010.

Paper 11

Utilising the complementary characteristics of wind power and hydro-power through coordinated hydro production scheduling using the EMPS model.

Utilising the complementary characteristics of wind power and hydropower through coordinated hydro production scheduling using the EMPS model

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1. Abstract

This paper investigates system benefits of incorporating wind power in hydro production scheduling using the EMPS model for the Nordic power system (Nordpool). It is shown that if wind energy production is incorporated in the hydro production scheduling model, it will increase the value of wind power. The increased value is associated with a better management of the water reservoirs, resulting in reduced water spillage.This is due to the complementary characteristics of wind and hydropower. The simulated value of wind energy is up to 9 % higher compared to the value of wind energy sold at weekly spot price. The results are specific for the case study. The wind energy model presented can be readily applied for utilities with hydropower production considering future investments in wind power.

2. Introduction

Until today, Norwegian domestic electricity supply has been almost entirely based on hydropower; one of the few sustainable electricity supply systems present today. Hydro schemes are, however, becoming increasingly unattractive to develop as they conflict with environmental concerns (i.e. nature preservation and tourism). Other sustainable alternatives must be considered. Wind power is the most promising alternative because of the very good wind resources along our coast. The expectations associated with wind power is reflected by the numerous wind power project applications now under consideration by NVE (The Norwegian Water Resource and Energy Directorate). These projects amounts to at least 830 MW of wind power (NVE, 2000)

Our hydropower system is with its 650 power stations widely dispersed: Geographically, in size, regularity and inflow characteristics. This diversity brought awareness of the advantages of power pooling, as a means for utilising complementaries between the once individual local power supply systems. "The Association for the Integrated Operation of Southeast Norway Power System",

formed in 1932, can be viewed as an early predecessor to the Nordpool power market of today. The utilisation of complementary characteristics are also interesting features regarding wind power and hydropower. The purpose of this paper is to identify and possibly quantify the advantages of these complementaries.

3. Large scale wind energy in Mid-Norway

The region Mid-Norway is selected as a case study for integrating from 100 up to 1000 MW of wind power. The region has a total demand of ca. 17 TWh per year (1999), and a production capacity of 12.5 TWh in a year with normal hydrological conditions, thus being a net importer of energy. Mid-Norway has market access through the transmission capacities to Helgeland (900 MW), Northern Sweden (500) and Østland (300 MW).

There are several utilities within this region, but for simplicity, our study is kept on a regional level as illustrated in figure 1.
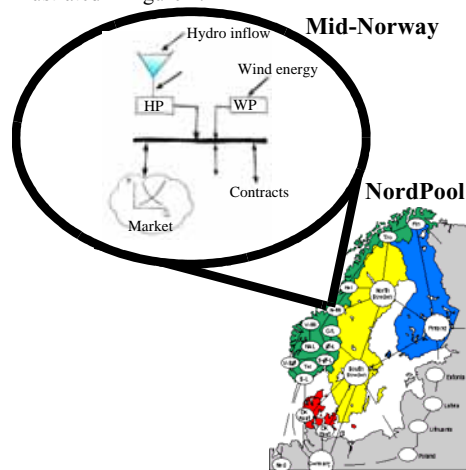

Figure 1 A representation of the Nordpool power market system subdivided into 18 interconnected areas. The close-up shows the Mid-Norway area. Nordpools exchange with Germany is also included.

The different options of production, market exchange and contractual obligations are illustrated in figure 2. As can be seen, the hydro inflow is

stochastic. Norway is 99% hydropower based and 48% of the Swedish supply comes from hydropower (Nordel, 1998). Consequently, the electricity market prices will also be stochastic.
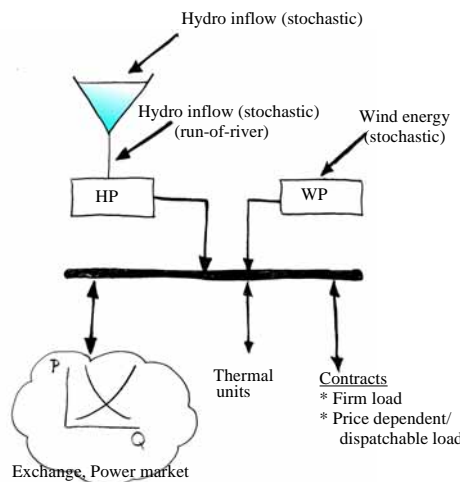

Figure 2 An aggregated representation of the power system in the area Mid-Norway. HP represents the hydropower stations, WP represent wind energy sites.

The demand is described in terms of *firm load* where a fixed amount of energy is sold at a fixed price, and *price dependent/dispatchable loads*. The latter can be dispatched by the consumer depending on spot price. (For example, flexible heating systems that switch between electricity oil depending on price). Now, introducing wind power as another stochastic source of production does not significantly change the production scheduling problem. The energy value of wind power depends on its complementary characteristics with the hydro inflow, the crucial part of long term production scheduling still being the management of water reservoirs.

4. The EMPS model

The EMPS model (EFI's Multiarea Power Scheduling Model) was originally developed for hydro production scheduling purposes (Flatabø et al. 1988). After the introduction of the Nordpool market, it has also served as a tool for price forecasting. In brief, it can model interconnected areas of production and consumption. The hydropower system in each area can be modelled very detailed, while the thermal units, demand and dispatchable loads are described into less details. Our data set contains 18 areas comprising the nordic power exchange; Norway, Sweden, Finland and Denmark. Additionally, Germany is included in the model (see figure 1). Time resolution is one week, and the hydro inflow data is based on the period

1961-90 with weekly inflow data for each hydrological unit.

The EMPS computation has two parts. In the *strategy* part, the water value of the reservoirs are determined using a SDP (stochastic dynamic programming) algorithm on aggregated reservoir representations of each area. The *simulation* part calculates the optimal hydropower schedule (that is, the schedule that will maximise expected profit of the area) for a sequence of 30 hydrological years, resulting in time series of optimal reservoir contents during the seasons and the corresponding price formation as shown in figure 3 and figure 4.
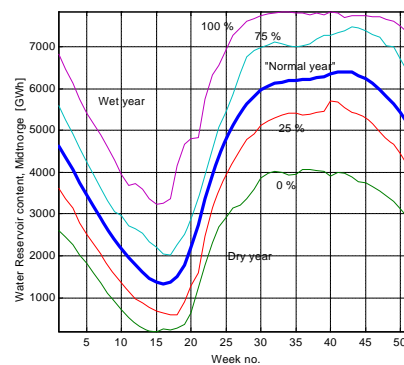

Figure 3 Water reservoir curves from the reference case (1999) generated by EMPS. The EMPS model optimises the management of reservoirs with respect to profits.

The thick line shows the expected reservoir content in a year of "normal" hydrological conditions, while the thin lines represent percentiles of the distribution rendering the stochastic inflow described in time series from 1961-90. During dry years, a low reservoir filling is optimal, (0 % percentile in figure 3), corresponding to high prices
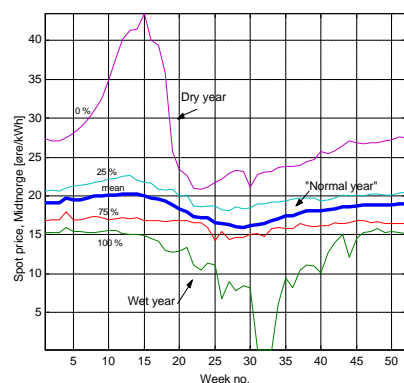

Figure 4 Price prognosis of the reference case (1999) generated by EMPS

in figure 4 (see 0% percentile). Conversely, wet years result in low prices (see 100% percentile in

figure 4), making it more profitable to save water for later (100% percentile in figure 3).

Utilities in the Nordic power market usually makes use of EOPS (Efi's One-area Power Scheduling Model), a sub model of EMPS, where the production scheduling in one area is optimised. The market price forecast (figure 4) is then taken as an exogenous input. The models of production unitsm demand and dispatchable loads are identical to those of EMPS.

5. Modelling wind energy in EMPS

Wind energy for long-term planning purposes can be modelled in the very same way as run-of-river power production. Though the wind power may fluctuate significantly within a week, a day, or even hours - it is not essential for long term production scheduling decisions. Wind energy can be modelled as a run-of river inflow where the stochastic hydro inflow replaces a stochastic wind energy inflow. Time series from Ørland runway was provided from DNMI[1] for the years 1961-90. The wind speed series were converted into wind energy series, assuming wind turbines of 1.5 MW and 3000 full-load hours a year. The high utilisation time is in accordance with experience from the first 1.5 MW wind turbine in operation at NTE in Mid-Norway. The energy series was was fitted into the format of the EMPS data base[2]. The construction of wind energy time series and statistical analyses of these have been presented in earlier work (Tande et al. 1999). The main results of the statistical analyses are presented below in figure 5 and figure 6.
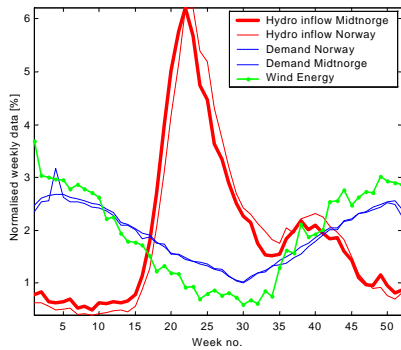

Figure 5 Seasonal variations of hydro inflow, wind energy and demand in the Mid-Norway area. Hydro inflow and wind energy data plotted as mean values of weekly time series of the period 1961-1990.

The complementary characteristics of hydro inflow and wind energy served as a motivation for this paper. As may be observed, the wind energy production in Mid-Norway is remarkably well

1. The Norwegian Meteorological Institute
2. The data base used by the EMPS model is the EFI's HYDARK data base

correlated with the demand curve, whereas the yearly variations of hydro inflow and wind energy seem to be weakly correlated (a correlation coefficient of 0.45). The seasonal characteristic is expected to be to be the most influential: Up to 70% of the wind energy production takes place during winter.
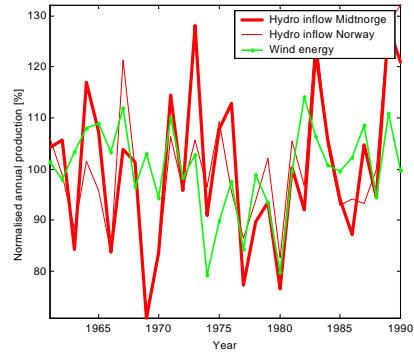

Figure 6 Yearly variations of hydro inflow and wind energy. The data are mean values of weekly times series from the period 1961-1990.

6. Simulation results

First a reference scenario without wind power was established, time span of the analysis being one year. For each new simulation, 100 MW of wind power in Mid-Norway was added (corresponding to 300 GWh of wind energy). 10 simulations were performed, reaching a maximum of 3000 GWh wind energy. The main concern was to identify how the increasing amount of wind energy would influence the optimal scheduling of hydropower production, and to identify the mechanisms in play. The findings of the simulations are shown below in figure 7, where each step on the line indicate the increased amount of wind energy.
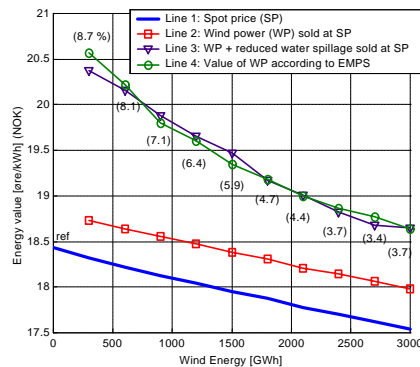

Figure 7 Value estimates of wind energy.

Line 1 represent the simulated yearly average spot price referred to the Mid-Norway area[3]. Of course,

the spot price is reduced as the supply of wind energy increases. (A online video animation is available, showing how spot prices change with increasing amount of wind power, see Vogstad (2000:4)).

Line 2 shows the value of wind energy when sold directly at spot price each week, simply computed as

$$\frac{1}{52}\sum_{i=1}^{52} e_i \cdot p_i \qquad (1)$$

where e_i denotes wind energy produced and p_i denotes the spot price in Mid-Norway within the week i. A comparison between figure 4 and figure 5 explains why the value of wind energy sold at spot price each week gives a higher yearly average value than the yearly average spot price.

Line 3 represents the value of wind energy, plus the saved amount of water spillage sold at yearly average spot price. The reduced amount of water spillage is a result of the new hydro production schedule, taking wind energy into account. The reduced amount of spilled water as a function of wind energy is shown in figure 8.

Line 4: The total value of wind power is calculated as the difference of the production costs between the simulation with wind power and the reference case (without wind power). The production costs are calculated as follows: Power sold to *dispatchable loads* at disconnection price[4] - production cost of thermal units - cost/income of buying/selling in the market. The total cost is also adjusted for the changed value of reservoir content by the end of the year. The amount of dispatchable load may change as the spot prices change. As can be seen from figure 7, these values are very close to the ones represented by *Line 3*, suggesting that the added value of wind energy can be explained by the water spillage saved. Numbers in parenthesis indicate the increased value in per cent from that of wind energy sold at spot price (Line 2). Comparing the resulting water reservoir curves for each simulation, we could observe that the optimal reservoir level dropped as the amount of wind energy increased. To see how increasing amount of the optimal reservoir level changes with

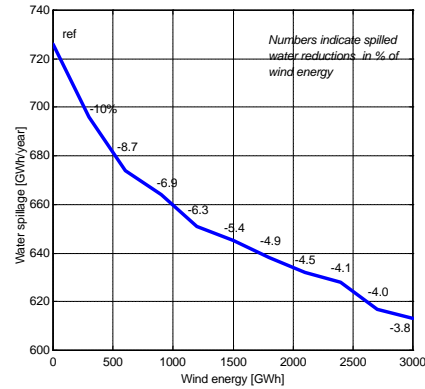increasing amount of wind energy, see Vogstad (2000:3)

Figure 8 Water spillage reductions with increasing amount of wind energy.

7. Discussion

7.1 Simulated spot price

The increased value of wind energy ranges from approximately 9% declining to 4% as the amount of wind energy increases. The *level* of the spot prices may be questioned. As may be observed in figure 4, the simulated spot prices seem too high compared with recent years observed spot prices, average prices ranging from 11-13 øre/kWh (Nordpool, 2000). There may be several reasons for this. One is the behaviour of the utilities. The utilities may choose to dump the prices, as was observed when Finland entered the market. The hydrological inflow conditions have also shifted towards wetter years (Vogstad, 2000:3), increasing the hydropower production. A "normal" year in our model is the mean hydrological year of the period 1961-1990. Another uncertainty are the actual production costs. Usually, these costs are kept confidential, and only estimates can be obtained. A lot of efforts could be devoted to price modelling, but it has not been the aim of this study. The emphasis in this study is the *relative* increased value of wind power, irrespective of the spot price level.

7.2 Sensitivity of the results

The results are sensitive to the calibration[5] of the EMPS model. Small changes in the calibration parameters influenced the wind energy's value and water spillage, but the relative proportions of the results in section 6. remained the same. The

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3. Because of the capacity constraints, spot prices will differ from region to region.
4. Disconnection price is the price at which the load is dispatched

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5. The reservoir curve levels of each area in the EMPS model must be adjusted manually. This is before using the model for simulation.

calibration prior to simulation must therefore be performed carefully.

The initial reservoir content was set to 60% for most areas in Norway. Changes of the initial reservoir content does not affect the results significantly because the remaining water content is sequentially given as an input for the next of the 30 years simulated.

7.3 Comparison with previous work

In this study, the statistical properties of wind power observed was incorporated in the hydro production scheduling problem. Most previous studies concern thermal dominated energy systems. In thermal systems, new additions are evaluated in terms of their energy value (fuel savings), and capacity value (associated with the reliability of the system). A method for intermittent sources was presented by Hoff (1998). For a hydro power based utility, the value of wind power must be estimated on the basis of improved profits from buying and selling in the market, and through management of the water reservoirs. The approach used by Bernard et al., was based upon a cost-benefit analysis, proposed by Grubb (1991). Söder (1999) showed that wind energy can increase the energy reliability of wind power in a hydro dominated system, and also the energy value.

None of the above mentioned studies took advantage of incorporating wind energy in the hydro power scheduling problem. The increased value of wind energy in this study is therefore somewhat higher than previous studies indicate.

8. Conclusion

It is shown that incorporating wind energy in hydro production scheduling can increase the value of wind power. This was the case for Mid-Norway, where introducing wind energy enhanced the hydro scheduling by reducing water spillage. The value was found to be 9% higher than wind power sold at spot price for 100 MW of wind power, but this percentage decreased to to 3.7% when the amount of wind energy increased to 3000 GWh.

9. Acknowledgements

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(1) http://www.stud.ntnu.no/~klausv/Documents/ewec99.pdf
(2) http://www.stud.ntnu.no/~klausv/Drafts/tilsigsstatistikk.jpg
(3) http://www.stud.ntnu.no/~klausv/Documents/magasinkurver.mpg
(4) http://www.stud.ntnu.no/~klausv/Documents/priskurver.mpg
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Paper 12

Operational Implications of Wind Power in a Hydro Based Power System

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OPERATIONAL IMPLICATIONS OF WIND POWER IN A HYDRO BASED POWER SYSTEM

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ABSTRACT: Implications of operating wind turbines in the Norwegian hydro-based power system are studied. The study uses thirty years of wind speed data measured at five different locations to give a normalised measure of expected supply from wind turbines situated along the Norwegian coastline. It is found from these that the total annual supply from wind turbines may vary ± 20 %. In comparison, the total annual inflow to the Norwegian hydropower stations may vary ± 30 %. Hence, wind energy seems to be less variable than hydropower in terms of annual energy supply. Seasonal variations in the wind energ supply are also estimated and compared with electricity consumption and inflow to the hydropower stations. It is found that the seasonal wind energy variation closely matches the consumption. This is beneficial. Further analysis indicates that there will always be some weekly wind power production as long as the wind turbines are situated both in the north and south of the country. Limited transmission capacity in the northern parts of Norway may be a limiting factor for utilising the wind resources. More detailed analyses of the transmission system must however be conducted before any conclusions may be stated on this matter.

Keywords: Statistical Analysis, Integration, Grid, Norwa

1 INTRODUCTION

In Norway, the power supply system is almost entirel based on hydropower plants with reservoirs. This supply system has until recently been sufficient to serve all domestic loads. In 1996 however, Norway experienced a dry year, resulting in a net import of over 9 TWh to cover consumption, i.e. 8 % of the total consumption was served by import of energy from the neighbouring countries. Figure 1 shows the actual development of the supply and consumption for the period 1975 to 1997.
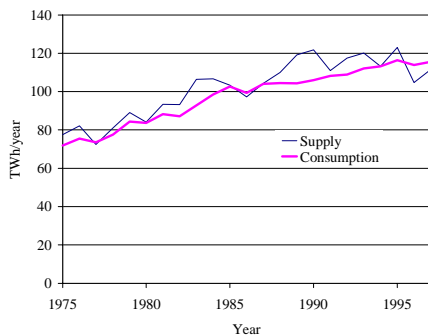

Figure 1: Actual supply and consumption of electricity in Norway.

Estimates of the hydropower generation capacity installed in Norway today indicate that it may supply 113 TWh during a year with normal hydrologic conditions. This is 3 TWh less than the actual consumption in 1997. As the Norwegian government has stated as a goal that all domestic loads should be supplied from renewable sources during a year with normal hydrologic conditions, and as it is difficult to obtain public acceptance for building more large hydropower plants, wind energy is in focus. Large areas with little population and fairly high annual average

wind speeds make the wind energy potential in Norway to be one of the biggest in Europe. Starting to investigate large-scale exploitation of the wind resources, studies are now carried out to quantify the implications this may have on the power system operation. The methodology and results of the studies are relevant not only for the planning of wind power in Norway, but to all those involved with assessment of the impact of wind power on power syste operation.

2 STATISTICAL ANALYSIS OF WIND DATA

Wind data from five different locations as indicated in Figure 2 is applied as basis for the analysis. The data are all from meteorological masts located in connection with airport runways, except for the data from Helnes, which is from a meteorological mast operated in connection with a lighthouse. The wind data is procured from the Norwegian Meteorological Institute (DNMI), and should according to DNMI be of consistent quality for the measurement period in question.
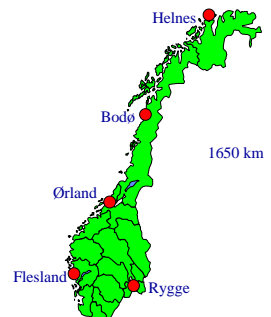

Figure 2: Map of Norway with location of applied wind speed data.

The wind data are all from the period 1961 to 1990, measured ten meters above ground level (agl), and collected four times per day as ten-minute-average data. Calculated annual-average wind speeds for the five locations are given in Table 1.

Table 1: Annual average wind speeds at 10 m agl.

Location	Rygge	Flesland	Ørland	Bodø	Helnes
Avg. (m/s)	3.5	3.7	5.8	6.3	6.7

The measurements are applied to calculate time-series of normalised wind energy production. Hence, the time-series are only applied to give an estimate of the relative variations in the production, and not the actual energ output from any given wind power installation. In spite of this, it may still be dubiously to use time-series with very low annual-average wind speed as the case is for Rygge and Flesland to estimate the relative variations in production. All time-series are however treated and analysed to see if fair results still may be achieved.

The time-series with normalised wind energy production data are calculated so that they give week by week production in percent of the thirty-year-annual-average production. This is done as described in section 2.1. The analysis of the normalised time-series is described thereafter in section 2.2.

2.1 Calculation of time-series

The wind speed data is first converted to one-week-average data by simple block averaging. Secondly, the data is scaled to give an average utilisation time of 3000 hours pr year for an assumed 1.5 MW wind turbine. Further, the wind speed variation within each week is assumed to fit a Rayleigh distribution, and the average production from the assumed 1.5 MW wind turbine is calculated for each week according to equation (1).

$$P_{i,j} = \int_0^\infty P(v) \cdot f_{i,j}(v) dv \qquad (1)$$

Here, $P_{i,j}$ is the average output power from the wind turbine during week i in year j, $P(v)$ is the power curve of the assumed 1.5 MW wind turbine, and $f_{i,j}(v)$ is the Rayleigh distribution of the wind speed v for the relevant week.

Finally, normalised data is calculated according to equation (2) so the thirty-year-annual-average production for each of the series becomes 100 %.

$$e_{i,j} = \frac{P_{i,j}}{\frac{1}{30} \cdot \sum_{j=1}^{30} \left(\sum_{i=1}^{N_j} P_{i,j} \right)} \qquad (2)$$

Here, $e_{i,j}$ is the normalised production during week i in year j, and N_j is the number of weeks in year j.

2.2 Analysis of time-series

Table 2 gives the standard deviation, minimum and maximum values of the analysed time-series. It is seen that

these values are very much the same for all the time-series.

Table 2: Standard deviation, minimum and maximum values of the analysed normalised time-series.

	Rygge	Flesland	Ørland	Bodø	Helnes
Std (%)	0.82	0.99	0.95	0.92	0.94
Min (%)	0.00	0.00	0.10	0.01	0.00
Max (%)	3.23	3.33	3.29	3.30	3.27

The time-series with normalised wind energy production data are applied to estimate seasonal and annual variations in the production.

The seasonal variations are estimated for each of the locations as average patterns for the thirty years of data. The resulting series are shown in Figure 3. It may be seen from the figure that all series except Rygge and Flesland show similar seasonal patterns with relatively higher energy output during the winter months.
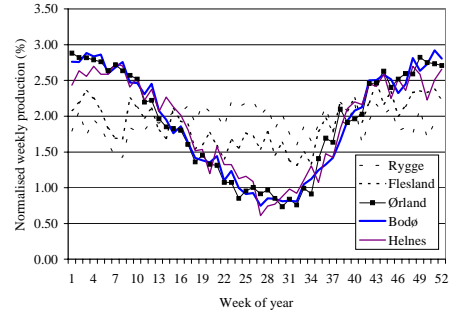

Figure 3: Seasonal variation of wind energy production for five different locations in Norway.

The estimated variations from year to year of the wind energy supply are shown in Figure 4. It can be seen fro the figure that the variations from year to year are within ± 20 % for Ørland, Bodø and Helnes, whereas somewhat higher variations are observed for Rygge and Flesland.
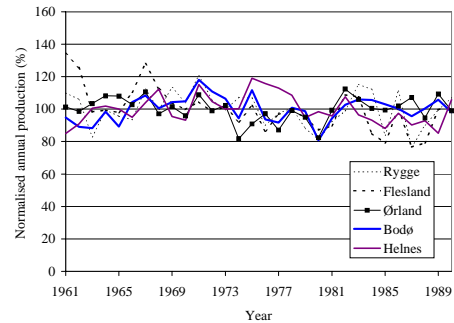

Figure 4: Annual variation of wind energy production for five different locations in Norway.

Table 3 gives the correlation coefficients between the full series. It is seen that Rygge and Flesland are weakly correlated with each other. Further, Rygge is not correlated at all to Ørland, Bodø or Helnes. Flesland is weakly

correlated to Ørland, and then less to Bodø and Helnes, i.e. the correlation gets less the further distance it is between the locations. Ørland, Bodø and Helnes are somewhat stronger correlated to each other, though with the same trend that the correlation gets less the further distance it is between the locations. This is as expected.

Table 3: Correlation coefficients between the full wind energy time-series.

	Rygge	Flesland	Ørland	Bodø	Helnes
Rygge	1.00	0.54	0.16	0.07	-0.04
Flesland	0.54	1.00	0.42	0.34	0.18
Ørland	0.16	0.42	1.00	0.76	0.54
Bodø	0.07	0.34	0.76	1.00	0.64
Helnes	-0.04	0.18	0.54	0.64	1.00

It is believed that the analysed time-series give reliable information about the wind conditions in the proximity to the measurement locations. The time-series from Rygge and Flesland are however probably not representative for actual conditions in the region at locations that are better exposed to the wind, i.e. where it is relevant to install wind turbines. Hence, for the further study, only the time-series from Ørland, Bodø and Helnes are applied. This is still considered to give a fair picture of how wind power may be operated together with the rest of the power system of Norway. The current plans for installation of wind farms in Norway as indicated in Figure 5 give further support for not applying the data from Rygge and Flesland.
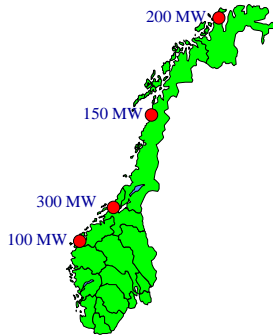

Figure 5: Indication of current plans for installation of wind farms in Norway.

3 INTEGRATION OF WIND ENERGY

A first assessment of the operational implications of integrating wind power in the Norwegian power system is conducted. This is done by assuming that wind turbines are installed at locations that in sum gives the normalised average of the time-series from Ørland, Bodø and Helnes. This average time-series is then a measure of the total normalised wind energy output in Norway, and may be compared with the total normalised consumption of electricity and the total normalised inflow to the hydropower stations.

Figure 6 shows a comparison between the annual variations of wind energy and inflow to the hydropower stations. It is

seen that the annual wind energy supply may vary up to ± 20 %, and that the total annual inflow to the hydropower stations may vary ± 30 %. Further it is seen that there is a positive correlation between the two. The correlation coefficient is calculated to be 0.32. Hence, there is a tendency that a dry year with little inflow to the hydropower stations also will be a year with less wind energy. This may be regarded as unfortunate. However, as the annual wind energy supply varies less than the annual inflow to the hydropower stations, utilisation of wind energy in Norway may have a positive effect on the overall annual supply availability.
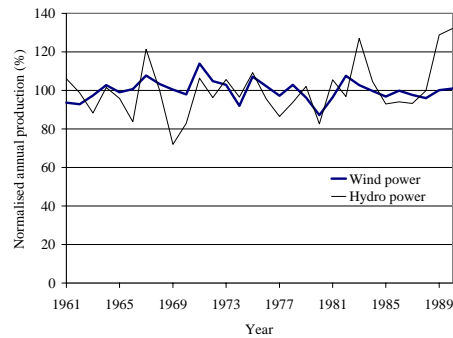

Figure 6: Normalised annual variations of hydro and wind power.

The thirty-years-average-weekly variations in wind energy and hydro inflow are shown together with the current demand profile for Norway in Figure 7. From this figure it is seen that the seasonal variations of the wind energy closely matches the demand profile, whereas the pattern for the hydro inflow is almost opposite. The close match between the seasonal demand and the wind energy indicates that utilisation of wind power in Norway to supply some fraction of the deficit between the demand and the hydropower supply will not require extra pondage or extra stress on the transmission links to the neighbouring countries. Considering that the deficit between the consumption and the hydropower supply capacity already in 1997 was 3 TWh, quite substantial amounts of wind energy may be utilised in Norway before this would require extra pondage or give more stress on the transmission links to the neighbouring countries.
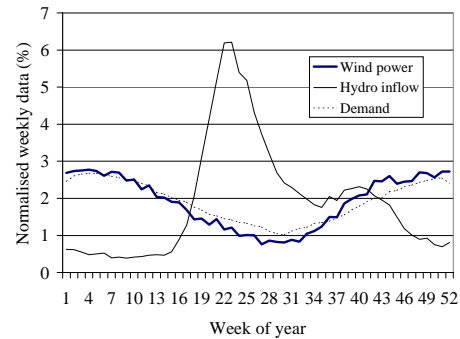

Figure 7: Normalised weekly hydropower inflow compared with demand and wind power production.

The actual correlation coefficients between seasonal data for wind power, hydro inflow and demand are given in Table 4.

Table 4: Correlation coefficients between seasonal data for wind power, hydro inflow and demand.

	Wind power	Hydro inflow	Demand
Wind power	1.00	-0.72	0.96
Hydro inflow	-0.72	1.00	-0.72
Demand	0.96	-0.72	1.00

Certainly, the supply from wind turbines may fluctuate significantly within short periods. Reliable supply thus requires operation of spinning reserve to take unexpected variations in the supply from wind turbines. Online central monitoring of the wind energy production and application of forecasting techniques may reduce the need for spinning reserve. Further, the total power from more wind power plants installed e.g. along the Norwegian coastline is expected to be less fluctuating than the total power from a installation concentrated within a narrow geographic area. Analysis of the time-series with normalised wind power production actually indicates that there will always be some weekly wind power production as long as the wind turbines are situated both in the north and south of the country.

4 GRID ISSUES

Grid issues may be a limiting factor for utilising the wind resources. Especially in the northern parts of Norway, the transmission capacity is limited, and may be a bottleneck for large-scale utilisation of those wind energy resources. More detailed analyses of the grid must however be conducted before any conclusions may be stated on this matter. This may be done by application of SAMLAST [1]. This model combines power-market simulations and load-flow analyses. The power-market model is illustrated in Figure 8, showing the assumed market areas.
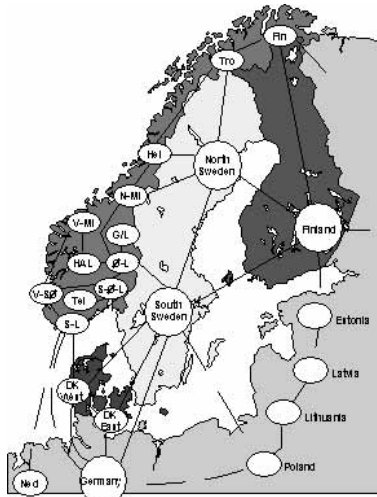

Figure 8: Illustration of power-market model.

Combing the power-market model with a detailed load-flow model provides a substantial improvement in relation to earlier models when it comes to simulations of main grid utilisation in a market-based power system dominated b hydropower. The model has recently been further developed to enable studies of utilising wind energy using detailed data as input including time-series of normalised wind energy production.

Analysis using SAMLAST is carried out as a time-series simulation applying area specific load and meteorological conditions as input varying with time during the year. The effect of changing wind and hydrological conditions fro year to year is taken into account by application of thirt years of historical data. Simulation results include week by week quantification of transmissions losses, generation, operational costs, import/export and emissions fro thermal units. Comparing the simulation results achieved by assuming different amounts of wind power in the power system, the effect of large-scale exploitation of wind energy in Norway may be quantified.

5 CONCLUSION

Implications of operating wind turbines in the Norwegian hydro-based power system are studied. The study uses thirty years of wind speed data measured at five different locations to give a normalised measure of expected suppl from wind turbines situated along the Norwegian coastline. It is found from these that the total annual supply fro wind turbines may vary ± 20 %. In comparison, the total annual inflow to the Norwegian hydropower stations may vary ± 30 %. Hence, wind energy seems to be less variable than hydropower in terms of annual energy supply. Seasonal variations in the wind energy supply are also estimated and compared with electricity consumption and inflow to the hydropower stations. It is found that the seasonal wind energy variation closely matches the consumption. This is beneficial. Further analysis indicates that there will always be some weekly wind power production as long as the wind turbines are situated both in the north and south of the country. Limited transmission capacity in the northern parts of Norway may be a limiting factor for utilising the wind resources. More detailed analyses of the transmission system must however be conducted before any conclusions may be stated on this matter.

6 ACKNOWLEDGEMENTS

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