RISK AND INVESTMENT MANAGEMENT IN LIBERALIZED ELECTRICITY MARKETS

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Preface

This thesis has been prepared at the Systems Analysis Department at Risø National Laboratory and at the Operations Research section, Informatics and Mathematical Modelling (IMM) at the Technical University of Denmark in partial fulfillment of the requirements for acquiring the Ph.D. degree in engineering.

The thesis consists of a summary report with four chapters and a collection of five research papers written during the period 2000–2003. The papers are centered around the theme *Financial Risk in a Liberalized Electricity Market* with a focus on applied mathematical modelling and financial economics in the context of liberalized electricity markets.

At the time of writing four of the five research papers have been accepted for international publication.

Lyngby, September 2003

Jacob Lemming

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Finally, I would like to express my gratitude to Marianne for her continuous love and support throughout the process.

Papers included in the thesis

[A] Stein-Erik Fleten and Jacob Lemming
Constructing Forward Price Curves in Electricity Markets
Energy Economics
Volume 25, No. 5, 2003.

[B] Jacob Lemming
Price Modelling for Profit at Risk Management
To be included in:
Modelling Prices in Competitive Electricity Markets,
edited by Derek Bunn, due for publication by John Wiley and Sons in November, 2003.

[C] Jacob Lemming
Security of Supply in Liberalized Electricity Market Models
Submitted for publication, September 2003.

[D] Jacob Lemming and Peter Meibom
Including Investment Risk in Large-Scale Power Market Models
Accepted for publication in: Energy and the Environment, July 2003.

[E] Jacob Lemming
Financial Risk for Green Electricity Investors and Producers in a Tradable Green Certificate Market
Energy Policy, Volume 31, No.1, January 2003.

Summary

Electricity markets around the world are currently undergoing a liberalization process that changes the way electricity is traded and priced as a commodity. The electricity system has unique technical characteristics and the importance of electricity as a good in today's informational society is significant. Liberalization does not change the fact that politicians and regulators will be held responsible for keeping the lights on at reasonable costs. What changes is the tool used by regulators to accomplish this task. The introduction of competitive markets implies that market participants will be held financial responsible for their decisions. Regulated system operators remain responsibility for the physical balancing and electricity markets will therefore remain strongly regulated even after liberalization.

The combination of strongly regulated but competitive trading arrangements creates an environment where market participants will face a new set financial of risks comprising elements of competition, physical electricity characteristics and potential political regulatory intervention. On the other side of the market regulators and politicians will face the complex task of designing an electricity market that can outperform the previously regulated monopolies with respect to the three main requirements of security of supply, economical efficiency and environmental protection.

The economic theory of electricity markets forms an essential basis for decision making in a liberalized setting. The effect of financial risk on decision making is becoming an increasingly important topic within this field of electricity economics, due to the significant elements of uncertainty in electricity markets. A primary goal of the thesis is to increase the understanding of how the introduction of competitive markets affects the financial risk related to different decision problems within the areas of risk management and investments in liberalized electricity markets. Focus is on applied microeconomics and analyzes of the interplay between market design parameters and the technical characteristics of the electricity system.

Theory, literature and introduction to specific problem areas related to risk management and investments is provided in two separate introductory chapters. Contributions to research within specific problems areas is then subsequently provided by five research papers. The two topics are relatively broad, however the two chapters and five papers all share analyzes of financial risk in liberalized electricity markets as a common underlying theme.

The risk management part of the thesis focusses on modelling and measurement of financial risk in electricity markets. Key topics are electricity price modelling and the development of risk measures suitable for electricity market portfolios.

Risk management tools used for financial assets have until recently largely been transferred more or less directly to electricity market portfolios which include physical assets such as power plants and retail contracts. The hypothesis of this thesis is that the relevance of financial tools for electricity market risk management, depends critically on the technical characteristics of electricity assets and on the demands placed by the stakeholders in the electricity sector. In many cases such technical characteristics and stakeholder demands will imply a need for revised and renewed tools compared to those used for portfolios of financial assets. Chapter 2 in the thesis discuss such developments and provides a literature review of risk management modelling theory and applications in electricity markets.

Research papers A and B analyze electricity price modelling with a focus on the use of different types of input data. Paper A examines the combination of price scenarios from a technical bottom-up model and market data. Paper B examines the price modelling based on market based data and the use of the Profit at Risk (PaR) measure. Paper E is also related to risk management, however focus is here on strategies for wind turbine owners acting in both an electricity market and a market for tradable green certificates.

The investment part of the thesis focusses on market modelling and on the policy aspect of supply security. Key topics are analyzes of the pricing mechanism in electricity markets, implementation of financial risk in equilibrium market models and the effect of market design on capacity investments and supply security. Chapter 3 reviews investments in generation capacity in a liberalized market from both a policy and a market perspective. The individual investor perspective is also briefly reviewed, but is used mainly as a basis for the analysis of financial investment risk in a market perspective.

Paper D presents a framework for the inclusion of financial risk into partial equilibrium models of the electricity market. The focus is on the technical modelling aspects of uncertainty and risk aversion in this type of setting. The framework is motivated by the need solve the problems of model complexity and tractability that are associated with representation of stochastic parameters and practically applied risk measures such as PaR.

Paper C treats the policy aspect of investments in terms of the effects of market design on the balance between economical efficiency and security of supply. The paper describes the type of market imperfections and sources of market failure that are induced by the technical characteristics of the electricity system. A framework of different models for capacity regulation is presented and the models are analyzed and compared in relation to the market imperfections and sources of market failure identified.

The analysis of the interplay between the technical characteristics of the electricity system (engineering) and market design (economics) is a central theme throughout the thesis. Each of the five research papers contribute to this type of cross-disciplinary research within the field of electricity economics and provide directions for further research.

Resumé

Liberaliseringen af el-markedet ændrer må den hvorpå elektricitet handles og prisfastsættes som et gode. El-systemet har en række fysiske karakteristika som vanskeliggør markedsbaseret handel. Elektricitet spiller en central rolle i samfundet og liberaliseringen vil ikke ændre på det faktum, at politikere vil blive holdt ansvarlige for både forsyningssikkerhed og elpriserne på lang sigt. Liberaliseringen betyder derfor snarere omregulering end deregulering og kan først og fremmest betragtes som et skift i det værktøj, politikere og systemansvarlige anvender for at opnå en balance imellem de tre primære krav til elsektoren om økonomisk efficiens, forsyningssikkerhed og miljøbeskyttelse.

Den blanding af konkurrence og regulering, som liberaliseringen af elmarkedet medfører, fører til en radikal ændring i den finansielle risikoeksponering som de forskellige aktører i markedet elsektoren udsættes for. Producenter, leverandører og forbrugere eksponeres for finansielle risiko som følge af fluktuationer i priser, volumener og omkostninger. Politikere og systemansvarlige står på den anden side af markedet med den vanskelige opgave at designe markedet, således at finansielle risici og potentielle markedsimperfektioner ikke forringer muligheden for at opfylde de tre primære krav.

Både forbrug og produktion af elektricitet er forbundet med relativt stor usikkerhed på grund af en signifikant vejrafhngighed. Før liberaliseringen blev denne risiko båret enten af el-forbrugerene gennem tariffer eller

af samfundet som helhed via diverse subsidier til el-sektoren. Liberaliseringen flytter denne risiko til de enkelte aktører i sektoren, og analyse af finansiel risiko er derfor blevet et centralt område indenfor elektricitetsøkonomi.

Temaet for denne afhandling er finansiel risiko i et liberaliseret el-marked. Afhandlingens primære mål er, at øge forståelsen af hvordan introduktionen af et marked baseret på konkurrence vil påvirke den finansielle risiko forbundet med forskellige beslutningsproblemer inden for områderne risikostyring og investeringer i produktionskapacitet. Fokus i afhandlingen er på anvendt mikroøkonomisk analyse og på samspillet imellem markedsdesignparametre og de tekniske systemkarakteristika i el-systemet.

Afhandlingen er bygget op omkring to kapitler, som introducerer teori, litteratur og specifikke beslutningsproblemer indenfor de to hovedområder. Det forskningsmæssige indhold er koncentreret i fem separate artikler som bidrager med udvikling af matematiske modeller samt finansielle og mikroøknomiske analyser indenfor en række af de specifikke problemområder, som introduceres i de to kapitler.

Analyserne af risikostyring fokuserer på udvikling af modelleringsvrktøjer og risikomål, som specifikt er tilpasset de fysiske karakteristika, der kendetegner aktiverne el-markeds aktørernes porteføljer. Den tidlige fase af liberaliseringen har været præget af en mere eller mindre direkte overførsel af modeller fra den finansielle sektor til el-markedet. En central hypotese i denne afhandling er, at relevansen af disse værktøjer er stærkt betinget af, hvorvidt de er i stand til både at afspejle de tekniske karakteristika af fysiske aktiver og de specifikke krav, som de forskellige interessenter i elsektoren stiller.

Artiklerne A og B analyserer elprismodellering med fokus på betydningen af input data. Artikler A præsenterer en optimeringsmodel til konstruktion af forward pris kurver baseret på en kombination af markedsdata og scenarier fra en bottom-up model af el-markedet. Artikel B analyserer finansielle elprismodeller baseret udelukkende på markedsdata og brugen af Profit at Risk som risikomål i elsektoren. Artikel E er også relateret til risikostyring i el-markedet, dog er fokus i dette papir på strategier for vindmølle ejere i et reguleret system, hvor der handles både elektricitet og grønne certifikater.

Analyserne af investeringer fokuserer på markedsmodellering og policy aspekter. De primære emner er implementering af finansiel risiko ved investeringer i markedsmodeller og analyse af hvorledes forskellige modeller for kapacitetsregulering påvirker den økonomiske efficiens af markedsmodellen og forsyningssikkerheden.

Artikel D præsenterer et rammesystem for implementering af risiko ved investeringsbeslutninger i partielle ligevægtsmodeller. Artiklen er motiveret af de tekniske modelproblemer forbundet med implementering af stokastiske parametre og risiko mål i større modeller.

Artikel C omhandler de politiske aspekter af investeringer i el-markedet med hensyn til ansvaret for forsyningssikkerhed og økonomisk efficiens. Artiklen beskriver de markedsimperfektioner, der opstår som følge af tekniske karakteristika i el-systemet, og giver endvidere et overblik og analyse af en række modeller for kapacitetsregulering udfra dette perspektiv.

Analysen af hvorledes de tekniske karakteristika og det specifikke design af el-markedet spiller sammen og påvirker den finansielle risiko for forskellige interessenter er det centrale tema i afhandlingen. De fem artikler bidrager hver især til denne form for tværfaglige analyse, som kombinerer den økonomiske og ingeniørvidenskabelige tilgang.

Contents

Chapter 1

Introduction

In the previously regulated electricity sectors around the world, financial risks were borne by electricity consumers through regulated tariffs and by society as a whole through various forms of subsidies made to the electricity sector. The current move towards liberalization[1] of electricity markets in regions around the world involves both a transfer and a change of the financial risks that different stakeholders in the sector face. Liberalization expose stakeholders directly to financial risks in the electricity market and holds decision makers financially rather than politically responsible for their actions.

The general shift in financial risk exposure creates a need for the development of new modelling tools explicitly fitted to the specific characteristics of decision problems in electricity markets. Financial risks affect decision

[1] The introduction of competition and consumer choice in electricity markets is often termed "restructuring" whereas "privatization" refers to the transference of ownership from government to private corporations (Hunt & Shuttleworth (1996)). Doorman (2000) notes that the popular term "deregulation" understates the persistent need for regulation and suggests that "restructuring" is a more proper term. This thesis will use the term "liberalization" rather than "restructuring" to emphasize that the introduction of competition is a key element in the ongoing changes of electricity sectors around the world.

making at all levels of the supply chain. Consumers, retailers, producers and investors must include the potential effects of risk into the decision process. Such effects include the costs associated with potential periods of financial distress or bankruptcy as a worst case scenario.

The effects of financial risks depend largely on the market design. Politicians and regulators in the electricity sector have traditionally been responsible for balancing the three main requirements of security of supply, economical efficiency and environmental protection. Liberalization have changed the tool used by regulators to fulfil this obligation, however, the task remains unchanged. The effect of interactions between market design and technical system characteristics on the financial risks faced by different stakeholders is therefore a key issue both for regulators and for market participants.

The underlying theme of the thesis is analysis and modelling of financial risk in electricity economics. Financial risk is part of most decision problems in the electricity sector and the focus of this thesis is delimited to decision problems in the areas of risk management and investments in generation capacity. Electricity economics is highly cross-disciplinary subject, which brings together multiple sciences. The analysis is therefore further restricted to technical modelling aspects of decision problems rather than organizational, legal or social aspects. This delimitation highlights that key focus is on the interactions between engineering in terms of electricity system characteristics and economics in terms of the financial effects of market design.

A primary goal of the thesis is to increase the understanding of how the introduction of competitive markets affects the financial risk related to different decision problems within the areas of risk management and investments in liberalized electricity markets. This implies a focus on applied microeconomics and analyzes of the interplay between market design parameters and the technical characteristics of the electricity system.

A secondary goal has been to develop modelling tools that enable the inclusion of financial risk effects into decision making in electricity markets. Focus in this area is on applied mathematical modelling and finance theory and the perspective includes both tools for individual decision making and for policy analysis.

1.1 Competitive electricity markets

The electricity industry was considered to be a natural monopoly throughout most of the 20th century, due to economics of scale in generation and problems related to separation of transmission and generation activities (Hunt & Shuttleworth (1996)). Technological innovations in generation and improved transmission facilities decreased economies of scale during the last decades of the century and indicated that unbundling of transmission, distribution and generation activities could be possible, provided that a series of institutional difficulties could be overcome at reasonable transaction costs (Joskow & Schmalensee (1983)).

The current liberalization of electricity markets is still in a development phase. To become a successful experiment the market must provide a satisfactory balance between the three main requirements of economic efficiency, security of supply and environmental protection (ECON (2002)). The design of electricity markets is complex due to a series of electricity characteristics that affect supply and demand. These characteristics form the basis for the modelling risk management and investment decisions and are therefore briefly reviewed in this introductory chapter.

The physical characteristics of the electricity system complicates the design of electricity markets. Electricity is non-storable[2] flow commodity, which is consumed within a tenth of a second after its production by virtually all consumers (Stoft (2002)). The transmission system can be viewed as a shared pool with numerous entry and exit points, from which electricity can be injected or withdrawn. The supply and demand of power must be kept in a near continuous balance throughout the entire grid to avoid frequency and voltage fluctuations, which can damage generation and transmission equipment.

The pool structure of the electricity grid implies that electrons cannot

[2] Electricity can be stored as potential energy in batteries or water reservoirs, but such options are generally either economically inefficient or subject to constraints. The issue is addressed further in the following chapters.

be tracked from the generator to individual consumers. While this in itself does not create problems for market based trading it does create potential problems during periods where the system operator is forced to shed load. If demand exceeds available supply in real-time the system operator must as a last resort disconnect areas of consumers to avoid a frequency drop that could potentially result in a total system breakdown. Stoft (2002) describes the blackout problem as a consequence of two demand-side flaws in current electricity markets.

The first demand flaw is a lack of real-time metering and real-time billing, which causes a lack of demand elasticity in the market. This creates a potential for situations where real-time supply and demand curves may fail to intersect, because demand is completely inelastic at the maximum level of production capacity available in the market. In much earlier work on public utility pricing Brown & Johnson (1969) noted that this problem could be minimized if consumers could contract for reliability through a futures market. This type of physical reliability enforcement is however currently prevented by the second demand flaw. The second demand side flaw in electricity markets is described by Stoft (2002) as the lack of real-time control with power flow to specific customers. System operators do not possess the technology required to disconnect consumers at an individual level and are therefore not able to enforce physical contracts for delivery.

Both demand and supply are highly stochastic due to a significant dependency on weather conditions. Demand is affected significantly in the short-term by temperature swings, due to the use of electricity for heating or air conditioning purposes. In the short-term supply also fluctuates as a result of forced or planed outages of production plants or failure of transmission facilities. Combined with the lack of storage these uncertainties lead to highly volatile spot prices which are exacerbated in the short-term by the inelasticity of supply.

The weather dependence of supply is mainly a factor in systems with a significant share of hydro power. The level of precipitation follows an annual cycle and affects available supply years. This creates volatility in annual price averages, which has a significant effect on both consumers, suppliers and potential investors. The combination of long-run and short-run fluctuations in prices creates a financially risky environment and places significant demands on the design of markets for trading and hedging such risks in the electricity sector.

Investments in generation capacity have lead times of up to several years. The combination of an inflexible supply and significant intra-day, weekly and seasonal patterns in the demand for electricity, implies that the electricity system must include production units that run with a low capacity factor. Investment in electricity generation capacity is also capital intensive (Hughes & Parece (2002)). Combined with low and uncertain capacity factors this creates a highly risky financial environment for investments.

Electricity plays a central role in today's society and the right to a stable supply at reasonable prices is guarantied through legislation in both the EU and the US. The uncertainty related to potential political intervention during the development of an electricity market increases the financial risk for investors. To avoid unnecessary costly risk premiums and potential business cycles (Ford (1999)), the market design must minimize the effects of such political risk.

1.2 The Nordic Electricity Market

The Nordic electricity market[3] serves as a reference for a large part of the analysis performed in the thesis and a short review is therefore provided in this introductory chapter.

The Nordic electricity market is based on bilateral trading centered around a multi-national power exchange Nord Pool. Participants are free to trade power bilaterally, but must submit balance plans to the national system operators according to a set of country specific criteria. The multi-national power exchange Nord Pool provides reference prices for bilateral trading and organizes wholesale trading across subareas and national borders. Any bilateral trading across such borders must be submitted as bids through the Nord Pool exchange.

[3]By Nordic we refer to the the northern part of Europe in terms of the Scandinavian region and Finland.

Trading in the Nordic market model is structured around three[4] main sub-markets with different time horizons. To facilitate long-term trading and risk management Nord Pool runs a market for financial derivatives called the Eltermin market, which serves as an alternative and reference to bilateral Over The Counter (OTC) trading. To balance physical trades Nord Pool runs a day-ahead spot market (Elspot) where prices for individual hours 12-36 ahead are determined. Finally each of the national system operators operate real-time markets for handling of real-time imbalances. The system operator acts on behalf of the balance responsible parties as the sole source of demand in the real-time market. Actual deviations from consumption or production plans scheduled by the balance responsible parties are used by the system operator to determine the real-time market price, which is then subsequently used for financially ex post settlement of imbalances. Figure 1.1 illustrates the market structure and the key participants.

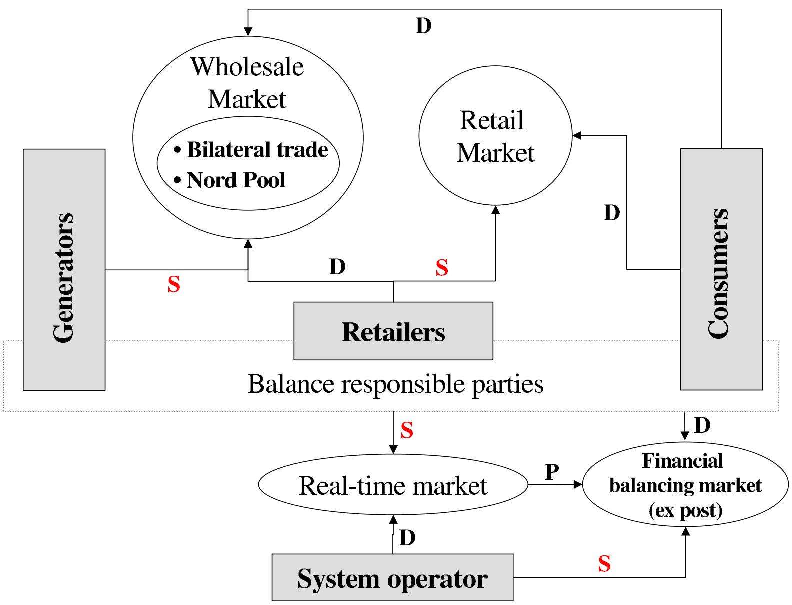

Figure 1.1: Basic structure of the Nordic electricity market.

No physical exchange of power takes place until real-time, but the day-

[4]An additional market for readjustment of production plans Elbas with up to one hour ahead trading are available to Finish and Swedish participants.

ahead market (Elspot) serves as the main market for physical planning with ex ante pricing of hourly blocks[5]. The national system operators regulate and operate real-time markets by ensuring that a certain volume of regulating capacity is kept available as reserves.

1.3 Overview of the thesis

The thesis is centered around the theme *financial risk management in liberalized electricity markets*. The analyzes are divided into two main areas focussing on risk management and investments in generation capacity. This section describes how the thesis adds to existing literature within these two areas and presents a short review of each of the five research papers included in the thesis.

Financial risk management theory provides a useful starting point for electricity risk managers, but must be adapted or renewed to fit the physical characteristics of electricity assets and technical characteristics of the electricity system. This thesis contributes to the development of electricity risk management tools through development and analyzes of risk modelling and measurement techniques suitable for electricity markets.

Price is the main tool used by the market to facilitate communication of preferences between market participants. The non-storable nature of electricity leads to highly volatile electricity prices and makes the market price a key factor in risk management decision problems. A main hypothesis underlying the analyzes presented in this thesis is that both market data and technical data about system constraints represent valuable information for price modelling. Development of methodology and electricity price models that include both bottom-up data and market data is therefore a central theme.

The modelling of financial risk related to investment decisions in generation capacity is treated from a relatively broad perspective. Focus is on the interaction between technical characteristics of the electricity

[5]Swedish and Finish participants have as noted the option to use the Elbas market where traded can be balanced up until one hour before real-time

system and market design parameters. The investment perspective is a market or policy based one. Electricity price is therefore viewed as an endogenous part of the model or analyzes, rather than as an exogenously given input for individual decision making.

The treatment of investments takes two main directions. A quantitative dimension focusses mainly on the inclusion of financial investment risk into partial equilibrium models i.e. technical modelling of how financial risk affects the capacity mix at a market level. A more qualitative policy oriented dimension focusses on how different aspects of market design affect investment decisions and hence the balance between security of supply and economic efficiency.

Both risk management and investments are relatively broad topics even when confined to electricity markets and a Ph.D. thesis could easily be written about either of the two topics. It is however the authors view that the underlying theme of financial risk modelling in electricity markets has provided synergies between the analyzes and improved the treatment of both subjects.

Structure of the thesis: The thesis contains two main chapters, a summarizing chapter and five research papers. The aim of the two chapters is to provide an overview of existing theory and literature within each of the two main research areas. They also serve as an introduction and motivation to the specific problem areas addressed in each of the five research papers.

Each of the five papers address specific problems areas related to financial risk modelling in risk management or investment related decision problems. The papers cover a relatively broad research area, but are bound together by a focus on interactions between technical characteristics and market design and the derived effect on financial risk and investment decisions in a liberalized electricity market.

Paper A: Paper A analyzes the construction of high resolution forward price curves in electricity markets. Forward prices express the market's risk adjusted expectations about future prices and provides valuable input data for decision problems such as risk management, production planning, investments in generation and construction of retail contracts.

Forward price curves are generally only partially revealed by the market through block products that trade with varying liquidity. The decision problems listed above will however often require complete[6] high resolution electricity forward price curves as input data. To solve this problem paper A suggests a Bayesian inspired approach where an apriori information set based on available market data is combined with price forecasts from a bottom-up model to form a forward price curve of high resolution.

The model is formulated as a simple non-linear programming problem. The model creates a forward curve that is consistent with arbitrage bands imposed by the bid/ask spreads of traded forward price blocks. The objective function ensures a smooth curve and minimizes the forward price curves deviations from a set of price scenarios based on bottom-up data. The approach is motivated by the hypothesis that both market data and bottom-up data can contribute with valuable information for electricity price modelling. Empirical analysis shows that the model performs better than best alternative models based solely on the use of market data.

Paper B: Paper B continues the analysis of input data for electricity price modelling. The paper examines financial price models based solely on market price data and analyzes the effect of both input data and model structure on the optimal decision to a simple electricity risk management problem.

The use of different "At Risk" measures for risk management in the electricity sector is discussed and the use of the Profit at Risk (PaR) measure is examined in a set of simple optimization problems. The empirical effects of price spike and volume risk modelling on the optimal solution to a PaR based risk management problem is examined, in a financial price model based on historical spot price data from the Nord Pool power exchange.

A primary conclusion of the analysis is that relatively small changes (such as the inclusion of an additional dry year) in the available set of historical market data used for parameters estimation affects the solution to the risk management problem significantly more than choices concerning the

[6]Complete in the that all time segments priced in the spot market within some time-frame ΔT are included.

structure of the price model.

Paper C: Paper C addresses the issue of market design and security of supply. The paper takes a policy perspective with focus on the effect of different market design parameters on investments in generation capacity and security of supply.

The paper starts out by reviewing how the technical characteristics of electricity systems lead to different types of market imperfections and sources of market failure. Based on this analysis a categorization and discussion of different models for capacity regulation in electricity markets is presented. The models are compared along dimensions such as capacity type and procurement method and analyzed in relation to the sources of market failure identified.

Finally, a more detailed analysis of a call option based method for regulation of operating reserves is provided and linked to current developments in the Nordic market model.

Paper D: Paper D analyzes how financial risk related to investment decisions in generation capacity can be included into partial equilibrium models. Focus is on the combined modelling of market prices and investments in a bottom-up modelling framework. The paper presents a Value at Risk based framework for inclusion of financial risk. The framework is based on a separate risk module, which is combined with a deterministic partial equilibrium model through an exchange of data. The degree of interaction between the two modules can be used to regulate the tradeoff between consistency and model complexity.

The methodology is motivated by the need to include uncertainty and represent risk aversion in a manner consistent with practical applications, without increasing the model size and complexity beyond tractable levels. A small scale model is implemented and used to test the effect of stochastic variable costs and stochastic demand empirically.

Paper E: Paper E examines financial risk for investors and producers in a market for Tradable Green Certificates (TGC). The TGC market is a policy measure for the support of renewable energy sources. The system examined is a consumer based version, where electricity consumers are obliged to green certificates on a separate market corresponding to a certain fraction of their electricity consumption. The paper examines financial risk in an electricity market where wind turbines are the main source of renewable electricity and hence certificate supply in the TGC market. Fluctuations in production volumes and imperfect information about future supply and demand are identified as the two main sources of uncertainty in this type of system and the potential effect on risk premiums associated with investments in renewable energy sources is examined.

The paper derives variance minimizing strategies for renewable producers acting in both the electricity market and the TGC market. A key point is that prices will be negatively correlated in the two markets. Production volume and market price will also be correlated in the TGC market and these negative correlations will have a stabilizing effect on the income of renewable suppliers. The analysis are confined to a specific setting where wind turbines make up a significant part of the supply side. However, the results illustrate that correlations between risk parameters and between markets must be addressed properly in order to deduce the effects of this type of policy design on the financial risks faced by different stakeholders.

Chapter 2

Risk Management in Liberalized Electricity Markets

Liberalization of the Nordic electricity market has introduced competition at both the wholesale and retail levels. In a competitive market producers and suppliers of electricity cannot pass financial losses directly on to consumers and liberalization therefore expose these players to a significant amount of financial risk. The objective of suppliers and generators has also changed with liberalization from cost minimization to maximization of shareholder value. This shift in objective implies that risk management should therefore be part of a firm's strategies only to the extent that it contributes to an increase in shareholder value.

Electricity markets have a series of special characteristics compared to other commodity and securities markets. These characteristics include highly volatile wholesale market prices, volume uncertainties and a significant element of political risk, due to the critical role that electricity based services play in today's society. To properly hedge risks in such an environment, generators and suppliers need risk management tools that are explicitly fitted to the specific characteristics of electricity markets. The development of such tools is a cross disciplinary task that combines financial economics and electrical engineering. A technical understanding of the electricity system is necessary to properly identify and model risk factors, whereas financial mathematics is required to measure and price the effects of relevant risk factors.

This chapter is divided into two sections. The first section describes the theoretical arguments for corporate risk management and reviews some cornerstones of risk management theory. Based on this introduction a set of key steps in the risk management process is described and issues specific to electricity market risk management are analyzed.

2.1 Risk Management Theory

The main goal of this section is to introduce some of the key concepts of risk management theory and to describe how they apply in an electricity market context. The aim is not to give a complete overview of risk management theory, but rather to provide a foundation for the analysis of specific problem areas presented in the papers of the thesis. The reader is referred to Dudley (2001) for a comprehensive overview of the different types of risk presented by electricity markets.

Before turning to a description of theory it is reasonable to ask why companies should direct resources towards risk management. Since all decision making should be based on the maximization of shareholder value criterion, risk management activities can only be justified to the extent that they are expected to create a value that will outweighs the costs.

The work of Modigliani and Miller on firm capital structure (Modigliani & Miller (1958)) lead to the formulation of a risk management irrelevance proposition. The proposition states that hedging cannot create shareholder value if the cost of bearing risk is the same within a company, as it is outside the company. In this case there is no reason for a company to undertake risk management activities, because shareholders can do this themselves according to their individual preferences at a similar cost.

The risk management irrelevance proposition is based on the assumption of perfect capital markets i.e. no transaction costs, no taxes and no information asymmetries (Fite & Pfleiderer (1995)). For risk management to create value one or several of the assumptions behind this proposition must be violated and hence drive a wedge between the cost of hedging inside and outside the firm. Another formulation is that risk management at the company level can only be justified by market imperfections. Based on such imperfections a series of factors that establish a link between company specific risk management and shareholder value have been identified (Stulz (2002)). These factors include:

- Cost of Bankruptcy and Financial Distress
- Cost of Funding New Investments
- Corporate Taxation
- Asymmetric information

Cost of Bankruptcy and Financial Distress: Uncertainty related to future earnings will generally increase the risk of bankruptcy. Bankruptcy is associated with a series of transaction costs such as legal expenses and a temporarily inefficient allocation of resources. The expected value of such costs decrease firm value from the viewpoint of shareholders and creditors. Creditors charge companies for this type of default risk by increasing the firms cost of capital during periods of financial distress. As a result of this companies can create shareholder value by ensuring a stable cash-flow.

Shareholders cannot eliminate the risk of bankruptcy and hence bankruptcy cost through individual risk management. The increased cost of capital during financial distress periods and the cost related to a potential bankruptcy can only be eliminated through hedging at the firm level. Risk management is therefore valuable to the company and it's shareholders as long the cost of hedging is less than the present value of expected distress and bankruptcy costs (Stulz (2002)).

Cost of Funding New Investments: Companies create value through investments in equipment and manpower. The root corporate value is generally derived from some form of superior know-how about how to exploit these investments within the company. Companies will therefore tend to have more information about future potential earnings of an investment than their creditors and this form of informational asymmetry implies that outside an financing of a new investment will tend to be more expensive than an internal financing through retained cash-flow. Risk management can therefore create value by ensuring that the company has sufficient internal cash-flow available to undertake value-enhancing investments.

Substantial leverage can also lead to situations with asymmetric incentives. For a highly leveraged firm shareholders will benefit from potentially positive outcomes of a risky project whereas debtholders will pay in case of negative outcome. This form of debt overhang can lead shareholders to accept risky projects with a negative Net Present Value (NPV) or debtholders to block risky projects with a positive NPV (Froot (1994)). This is again a case where a stable cash-flow and the use of retained earnings rather than leverage can help increase shareholder value by decreasing the possibility of suboptimal investment incentives.

Corporate Taxation: Non-linear tax structures can make risk management valuable. Structures where taxes increase with income or limits the ability to carry tax benefits from losses forward or backward induce an asymmetrical cost across the cash-flow distribution. This asymmetry will punish the company both in extreme profit scenarios and in extreme loss scenarios implying that risk management can increase the expected value of cash-flows. As taxation is applied to the corporate cash-flows, shareholders cannot obtain a similar benefit from individual hedging (Fite & Pfleiderer (1995)).

Asymmetric information: The principal-agent problem between shareholders and managers can lead to agency costs. Such costs occur when investors are not convinced that managers are competent or have the same interests as shareholders and debtholders. Risk management can help decrease the consequences of such asymmetrical information (Stulz (2002)).

Several other factors related to leverage, tax and asymmetrical information effects can be added to the list. For a comprehensive description the reader is referred to references such as Fite & Pfleiderer (1995), Ross

(1996) and Stulz (2002).

Having justified the use of corporate risk management we address the fundamental distinction between systematic and unsystematic risk introduced through the seminal works of Markowitz (1959) and Sharpe (1964). Unsystematic risk or idiosyncratic risk describes the firm specific risk, which investors can remove from their portfolios through diversification. Systematic risk is the part of an assets risk that is correlated with general movements in the global economy and hence cannot be removed by portfolio diversification. Shareholders will care only about systematic risk assuming that perfect portfolio diversification can be obtained at the shareholder level without any transaction costs.

Even if such an idealized setting could be envisioned at the shareholder level it cannot possibly be assumed to hold for corporations. At the corporate level unsystematic risks does matter and hedging can create shareholder value. Furthermore the real-world does present significant transaction costs both at the corporate and shareholder level. The distinction between systematic and unsystematic risk is therefore useful mainly for clarification. Unsystematic risk cannot simply be discarded as irrelevant, but should by included along with the costs of hedging or diversification in risk management modelling.

In electricity markets the distinction between systematic vs. unsystematic risk might prove most useful for policy regulation as suggested in Awerbuch (2000). He suggest that the societal value of renewable energy technologies is underestimated by traditional engineering models that fail to take into account diversification effects. The main point is that renewables such as wind power and photovoltaics (PV) are less correlated with the general economic movements than fossil based generation technologies and are therefore associated with a lower degree of systematic risk. Society as a whole may be seen as an investor with an extremely well diversified portfolio and the argument for separation of systematic and unsystematic risk is therefore more plausible for regulation strategies than for private investors.

At a general level corporate risk management is justified solely by its ability to create shareholder value. At a more detailed level it serves several functions for different stakeholders. Stakeholders range from small shareholder to market markets, creditors, insures and possibly reinsures. Stakeholder specific characteristics imply that different risk management policies and methods of risk reporting will benefit different stakeholders in an unequal fashion. To facilitate an efficient cost of risk transference between a company and its stakeholders Harris (2002) suggests characterizing risk by size, quality and direction. Size is measured quantitatively as the standard deviation or variance of a risk factor. Quality describes how much the stakeholder is affected by higher moments i.e. fat tails of a risk factor and direction provides information about the mix of risk factors. A key point in the analysis of stakeholders is that the kind of risk reporting desired by one stakeholder can differ widely from that desired by another.

2.2 The Risk Management Process

Corporate risk management is an elaborate process involving both managerial strategies, organisational aspects and technical modelling (Kollberg (2000)). This chapter is confined to a treatment of the technical modelling aspects of risk management. In Pilipovic (1998) risk management is defined as the process of achieving the desired balance between risk and return through a particular trading strategy. Based on this definition the term technical modelling can seen as the process of locating an optimal trading strategy under uncertainty and/or reporting corporate risk to stakeholders.

The following four steps can be used to describe the general structure of the construction process for technical risk management modelling[1]:

1. Choose time horizon and identify relevant risk factors
2. Model size and dependencies between factors
3. Mark to Market (MTM) book exposures
4. Choose risk measure and construct optimization or simulation model

[1] These steps concern only the construction phase. In the operation phase the model should be exposed to stress testing and backtesting to ensure the robustness and quality of the model.

Electricity markets have special characteristics that affect each of the steps in the modelling process. Electricity is traded in a series of forward markets and a real-time market (see chapter 1 for a description of the nordic market) where prices are formed by a series of fundamental drivers affecting supply and demand. This special market structure affects risk factors such as volume fluctuations in demand and production due to sudden temperature swings or forced outages of generation plants. Identification of relevant risk factors therefore require a detailed knowledge about technical constraints in the electricity sector.

Estimating the size and dependencies between risk factors is complicated by the fact that only a limited amount of data is available in the relatively new electricity markets emerging around the world. Mapping book (portfolio) exposures to market is also complicated in electricity markets due to the technical complexities of physical generation assets and retail portfolios combined with limited set of derivative products and a general lack of liquidity. Short-term futures do trade with a relatively high liquidity at Nord Pool (NordPool (2002)), however the derivatives required to replicate a physical asset such as a power plant trade at a low liquidity when seen as an aggregate.

Finally, based on the justifications for corporate risk management provided in the previous section there is a discrepancy between risk management in a value based financial sector and risk management in an electricity sector where cash-flow or profit is a key performance measure (Henney & Keers (1998)). This means that risk measures and time horizon for risk measurement cannot be adopted directly from the financial sector. Such choices must instead be made to reflect the nature of the corporation and the resulting stakeholder demands for risk reporting.

With respect to time horizon Denton (2003) distinguishes between operational/earnings risk for the short term (less than one month), trading/financial risk over the intermediate term (one month to one year) and asset valuation/equity risk for the long term (more than one year). Although short-term operational decisions and long-term investment decisions affect the cash-flow risk of electricity generators, it is generally fluctuations in profit seen over the annual accounting period that has the attention of shareholders.

In the following subsections we review each of the steps in an electricity market context by analyzing selected problems and describing references to relevant literature.

2.2.1 Risk Factors in Electricity Markets

The introduction of competition at both the wholesale and the retail level has created new risks for electricity market participants. Retailers and generators serve key functions in retail and wholesale markets and risk factor identification is therefore described from the viewpoint of these two players (see figure 1.1).

To provide a framework for identification risks are often categorized by type. A framework for general business risk is described in EIA (2002) as:

- Market risk (Interest rates, exchange rates, prices, etc.)
- Credit or default risk (Counterparties failing to meet their obligations)
- Operational risk (Equipment failure, human errors etc.)
- Liquidity risk (Inability to pay bills, bid/ask spreads)
- Political risk (New regulations, expropriation, etc.)

In Zenios (1993) financial risk is categorized in more detail into as many as eight distinct types encompassing market, credit and liquidity risk. The diversity of such categorization is illustrated by Pilipovic (1998) who suggests market, commodity and human risk as the three primary risk categories for energy companies. Market and commodity risk overlap with the categories listed above. Human risk adds an additional perspective, describing human errors in both the trading and modelling process.

Companies can potentially create value from management of risk in all of these categories. Because this thesis is concerned mainly with the technical modelling aspects we choose however to use a relatively simple framework where risk is categorized through its effect on cost C, price P and volume Q. The framework is based on the belief that profit or cash-flow $CF{=}P \cdot Q - C$ is the key parameter for corporate risk management in electricity markets (we elaborate on this in the following subsections).

Generation risk: Electricity can be generated by a mixture of technologies, which differ considerably with respect to their technical characteristics. Hydro, solar and wind power are driven by stochastic weather related factors with large volume uncertainties whereas thermal plants use fossil fuels associated with price uncertainties. The different risks that arise from different input fuels can however easily be described in the cost, volume, price risk framework.

Like most corporations, generators face cost risks related to investments, operations and maintenance etc. To a large extent these factors can however be controlled by the generator through various technical procedures and insurance contracts known from the pre-liberalization period. Thermal power plants also face an additional cost risk in terms of price fluctuations in the fuel markets. Again this is an area where generators have previous experience and the main new challenge therefore lies with estimation of the dependencies between fuel prices and other risk factors. In this context the relationship between natural gas and electricity prices known as the spark spread $SS = P_e - HR \cdot P_g$ has received considerable attention in the literature[2] Hsu (1998), Fleten, Dobbe & Sigmo (2003), Deng, Johnson & Sogomonian (2001), Gitelman (2002) or Frayer & Ulundere (2001).

Interest rate and exchange rate fluctuations represent additional cost risks and especially exchange rates have gained importance in the Nordic market where countries with different currencies trade on the common Nordic power exchange Nord Pool. Finally one can view the risk of default or credit risk as an additional source of cost uncertainty. However, since most of the generators revenue is based on electricity prices cleared by the Nord Pool exchange (NordPool (2003)) this risk is generally not very large unless the generator engages in significant Over The Counter (OTC) derivative trading.

[2] P_e is the electricity price (€/kWh), HR is the heat rate (kJ/kWh) and P_g is the natural gas price (€/kJ).

Volume risk is considerable for electricity generators as a result of the uncertain nature of weather dependent input for renewable technologies and the risk of forced outages due to failure in production equipment. Again volume risk is not a new phenomenon. Liberalization has simply changed the effect of volume risk, because it now coexists along side electricity price risk. Aside from the basic premise that negative consequences of risk cannot be passed along the supply chain to consumers, it is the portfolio effect from dependency between price and volume risk that makes volume risk a more complex topic in a liberalized markets.

Consider as an example a generator who experiences a forced outage during a cold winter period where peak load demand has created high wholesale market prices. If the generator has no financial derivative contracts he will miss out on a significant price spike related income in such a situation. If the generator has sold forward contracts (i.e. holds a short position) to hedge his future income, then the situation might be considerably worse. In this case the generator does not simply loose a potential profit, but incurs an actual financial loss on the short forward position corresponding to the difference between the spot price and the forward contract price times the volume contracted. Under normal situations this loss would be countered by the income from power production.

Unlike cost and volume, the electricity price was previously a regulated deterministic parameter and hence not a risk factor for electricity generators. The introduction of wholesale price uncertainty translates directly into cash-flow risk for the generator and this effect is significant. Not only because of the dependencies with costs and volume risks, but also simply because the wholesale price volatility in itself is extreme compared to levels known from other commodity markets (Clewlow & Strickland (2000)).

Retailing risk: Retailers serve as a link between the customer and the wholesale market. Retailers sell a product, which by consumers is valued through the services that it provides. As such electricity can be said to have both a quantity dimension and a qualitative dimension. Part of the qualitative dimension of electricity is that the services (light, heat, cooling etc.) are available to the consumer on demand at an acceptable price. As such consumption has an option like character in the sense that consumers create a demand for the option to consume whenever desired at a pre-determined fixed strike price. In a competitive market retailers must create such option contracts to match consumer needs and stay in business. For the retailers this leads to complex portfolios of electricity derivatives with values that depend primarily on the wholesale price. The California crisis provided an example of how crucial the design of retailer portfolios can be, in the presence of significant wholesale price risk (Brennan (2001)).

Technical costs are generally not very large in the electricity retailing business Joskow (2000) and the total cost risk for retailers is dominated by wholesale price fluctuations. Not only are wholesale price risks independently large, but they are also correlated with the volume risk of retailers. Because there are no economical storage possibilities, retail and wholesale demand must be identical in real-time and consumption is therefore a primary factor determining wholesale prices. If consumption turns out to be higher than expected this will have a positive effect on wholesale prices and vice versa. Volume and cost risk are therefore two highly dependent factors seen from the retailers point of view.

Price risk is generally low for retailers. The structure of consumer payments are generally stipulated in advance between the retailer and the consumer. Price risk is therefore limited to the effect that future competition will have on the retail price that the retailer can obtain in future contracts with consumers.

2.2.2 Risk factor modelling

The previous section identified wholesale electricity price fluctuations as a key risk factor for both retailers and generators. This section describes risk factor modelling using wholesale electricity prices as a case study. We discuss different approaches for modelling wholesale electricity prices as an individual risk factor and briefly discuss directions for future research on the modelling of dependencies between risk factors in electricity markets.

Different approaches for wholesale electricity price modelling are categorized in Skantze & Ilic (2000) as follows:

1. Quantitative Modelling of Electricity Prices: The dynamic properties of electricity prices is modelled as a stochastic process based on the statistical properties of historical price data and current derivative prices. Application can be found in references such as Joy (2000) ,Deng (2000) and Schwartz (1997).

2. Production (Cost) Based Modelling of Electricity Prices: Expectations about the future variable costs of units in the supply stack are combined with expectations about future demand to construct price estimates. Recent references dealing with electricity markets include Elkraft System (2001), Group (2001) and Botnen (1992).

3. Economic Equilibrium Models of Electricity Prices: Strategic behavior is incorporated in a cost based model structure using game-theoretic approaches to calculate economic equilibrium. References Rudkevich, Duckworth & Rosen (1998) and Hobbs, Metzler & Pang (2000) are listed as examples.

4. Agent Based Modelling of Electricity Prices: Market participants are divided into groups each with a separate objective function and set of decision rules. These strategies are used to derive dynamic price developments. References Visudhiphan & Ilic (1999), Visudhiphan & Ilic (2000) are listed as examples.

5. Experimental Modelling of Electricity Prices: The market is simulated through a controlled experiment where a group of people plays a game with conditions matching those of the market. Prices are modelled based on the results of the game. Denton, Backerman & Smith (2001) is listed as a reference.

6. Fundamental Modelling of Electricity Prices: Price dynamics are modelled through the impact of physical and economical price drivers. Parameters such as general economical trends or temperature are modelled econometrically using historical data and their effect on prices is specified within the model. Skantze, Chapman & Ilic (2000) is listed as an example and after presenting the review of approaches a detailed model based on this structure in presented in Skantze & Ilic (2000).

Weber (2002) presents a similar framework consisting of five categories separating fundamental, econometric, risk analysis based, game theoretic and technical analysis based models. Fundamental models, Econometric models, Risk analysis based models and Game-theoretic models correspond to categories 2, 6, 1 and 4 respectively in Skantze & Ilic (2000). One can note that risk based or quantitative (category 1) models resemble category 6 models in the sense that stochastic processes are structured to fit the fundamental characteristic of electricity prices e.g. with a sinusoidal function to capture seasonal variation. The two categories are however distinguished by the fact that category 1 models work directly with prices and do not include any econometric modelling of underlying price drivers.

Finally, Weber (2002) adds a new category by including the technical analysis concept known from finance where statistical analysis of historical price movements are used to predict future movements. Such models are related to category 1 models in the sense that no knowledge about the fundamental aspects of the market is used e.g. price earning ratios of stocks in financial markets or marginal production costs of generation units in electricity markets.

Each of these categories have different qualities and disadvantages depending on the amount of data available and the subsequent use the model. For electricity risk management there has been much focus on the distinction between the value of financial market data compared to fundamental data. Paper B employs this distinction to categorize models as being based on either a fundamental, a financial or a combined approach depending on the underlying data used.

The distinction between financial and fundamental models is similar to the distinction between the value of fundamental analysis vs. technical analysis known from the financial stock markets. Proponents of financial models subscribe to the "castles in the air" theory (Malkiel (1983)) where prices are seen more as a result of crowd psychology than of an actual valuation of the expected future cash-flow generation of an asset. Proponents of fundamental analysis believe that prices are a reflection of an actual cost or value estimation and that future prices can be predicted through knowledge about the development of underlying price drivers e.g. marginal production costs, precipitation, demand etc.

Compared to the framework listed above, categories 2 and 6 can be said to be fundamentally based price models whereas category 1 models and models based on the technical analysis approach can be seen as financially based price models. Category 3 is an example of a combined approach using both data types whereas category 4 and 5 focus mainly on human factors rather than fundamental or financial data.

The literature on financially based price models is heavily dominated by econometric models of the category 1 type and can be divided into two general approaches. The first approach describes the spot price $P(t)$ dynamics along with other key state variables using a set of stochastic processes. These processes are generally spilt into a deterministic component $f(t)$ modelling trends and cycles and a stochastic component $S(t)$ modelling the uncertainty or distribution of prices. The second approach is based on direct modelling of the dynamic evolution of the entire forward price curve. The two approaches are interrelated as forward prices can be derived from the risk adjusted or risk neutral version of a spot price process provided that an explicit solution to the stochastic differential equation governing the spot price can be obtained analytically (see Clewlow & Strickland (2000) for an example).

Applications of the spot price approach in electricity markets can be found in references such as Lucia & Schwartz (2002), De Jong & Huisman (2002), Pilipovic (1998), Deng (2000), Kellerhals (2001), Knittel & Roberts (2000), Barlow (2002), Escribano (2002)and Johnson & Barz (2000). References that apply the forward price approach to electricity pricing include Clewlow & Strickland (1999*b*), Koekebakker & Ollmar (2001), Clewlow & Strickland (1999*a*), Bjerksund, Rasmussen & Stensland (2000) and Joy (2000).

The main strength of financial models lies with the use of realized market prices, which include information about a series of non-tangible factors such as speculation, market power and the general psychology of traders. The main weakness is the potential lack of predictive power in historical data especially in the new and dynamically developing electricity markets.

The main advantage of fundamental models is the ability to represent all technical conditions in the system including supply, transmission and demand. Scenarios are easily calculated and data material has historically been extensively available. After liberalization such data has become private ownership and hence more limited. However, the main drawback lies with the process of translating the physical conditions into market prices. Prices are not necessarily defined by marginal production cost and factors such as strategic behavior, risk aversion and uncertain demand responses will induce significant model risk in fundamental models.

Paper B analysis financial based price models in an electricity market risk management context. A main conclusion from this paper is that financial models are highly sensitive to the set of historical data used. This conclusion is exemplified by the strong effect that the inclusion of a single additional dry year into a data set of six years has on the optimal solution to a simple profit at risk based risk management problem.

The problems sketched above with financial and fundamental models explain why practitioners often prefer models that combine the two model types. Fundamental data contains valuable technical information such as short-term weather related changes in supply and demand, which generally cannot be found in market data. Furthermore, the case study in paper B illustrated that available market data will often provide a poor representation of long-term conditions e.g. average annual price scenarios. In the hydro based Nordic market a significant number of yearly observations would be required to statistically estimate how fluctuations in annual hydrological conditions (wet years vs. dry years) will affect the average annual price. Unfortunately most of such observations would tend to lack predictive power by the time that a sufficiently large sample size became available. On the other hand market price data such as forward price curves represents important information about the comprised expectations and risk aversion of market players. This kind of data cannot be modelled from technical factors in any meaningful way.

An approach that combines the two types of models can be formed by using a bottom-up model to construct price scenarios and then calibrate these such that expected prices in the set of scenarios fit the observed forward price curve in the market[3]. If desired such calibration can include extrapolation of patterns found in historical data or parameters inferred

[3]If arbitrage restrictions are imposed this approach is equivalent to the forward price curve construction approach suggested in Fleten & Lemming (2003).

from other derivative prices e.g. volatilities from options.

Having considered each risk factor individually the risk manager must attempt to capture dependencies between factors. The most widely employed measure of dependency is the linear correlation. The linear correlation is however an insufficient measure of tail-dependency when the underlying distributions are non-eliptical. For electricity risk management we are highly interested in the tail-dependency, especially between volume and price risk because concordance between extreme realizations of these two variables can lead to significant losses for both generators and retailers. Electricity prices, plant availability and customer demand are however generally not accurately described by eliptical distributions and the tail dependency between these factors cannot be adequately described by the linear correlation measure[4].

The main obstacle for dependency modelling is the lack of data. Harris (2002) states that the uncertainties related to correlations estimates make even linear correlations estimates of risk factors in the electricity sector highly inaccurate and suggests a bottom-up modelling of casual relations between key variables and underlying factors as a partial solution. Although data is a limiting factor electricity generators and retailers can often limit the number of key risk factors considerably compared to financial portfolios. The data required for accurate advanced tail dependency modelling of a limited number of state variables such as plant availability, electricity spot price, and fuel price data might quickly become available as the market matures. For a nice introduction to non-linear dependency modelling in non-eliptical multivariate distributions the reader is referred to DeMatteis (2001).

Applications of extreme value theory in electricity risk management seems limited to single factor modelling in the current literature see e.g. Rozario (2002), Gencay & Selcuk (2002),Khindanova & Atakhanova (2002) and Bystrom (2001). Capturing the tail-dependency between risk factors is however essential for risk management in electricity companies and the use of multivariate extreme value theory in the electricity market will be an obvious area for future research.

[4]One can note that even if these variables could be described individually by simple normal distributions they might still have non-linear dependencies that would lead to a non-eliptical joint distribution.

2.2.3 Marking a portfolio to market: Hedging vs. Speculation

Marking a book or portfolio to market is the process of valuing a portfolio based on all available market information. Risk management is concerned with the potential change in portfolio value between today $T1$ and some future time reference $T2$ and marking a portfolio to market therefore involves both an estimation of the current market value of the portfolio and the future variability of the market value between $T1$ and $T2$ (Clewlow & Strickland (2000)).

The market value is an essential part of financial risk management, because it shows the true value of the portfolio in the sense that this is the value that can be realized as cash-flow by selling the portfolio in the market. Any attempt to value a portfolio differently than what is dictated by the market will conflict with the hypothesis of efficient markets and hence involve speculation. Decision makers can choose to speculate if they believe they have superior information, however such action should be separated from risk management and operational planning strategies to avoid accidental speculation. As a basic principle all non-speculative decisions such as risk management, operational planning and investment decisions should be based on market value maximization rather than expected profit maximization (Fleten (2002)).

Electricity cannot be economically stored and forward contracts therefore constitute the main building block for replication of more complex derivatives. Electricity is traded in hourly time blocks at the Nord Pool exchange, however the forward price curve will generally not be complete i.e. an individual hour occurring $n > 36$ hours ahead cannot be traded at the Nord Pool exchange. Instead a limited number of block products is traded. The block nature of forward contracts implies that the market will price a series of averages rather than individual hourly prices.

For a series of decision problems such as e.g. valuation of a generation plant, an investor require more detailed information about forward prices (in principle a price for every hour during the plant's lifetime). To solve this problem, paper A in this thesis suggests an approach that allows the decision maker to combine exogenous fundamental information with market data to create a high resolution forward price curves that obeys the arbitrage bands imposed by the market prices of the traded forward block products. Figure 2.1 illustrates how price scenarios from a bottom-up model can be combined with block price data to form a smooth high resolution forward price curve.

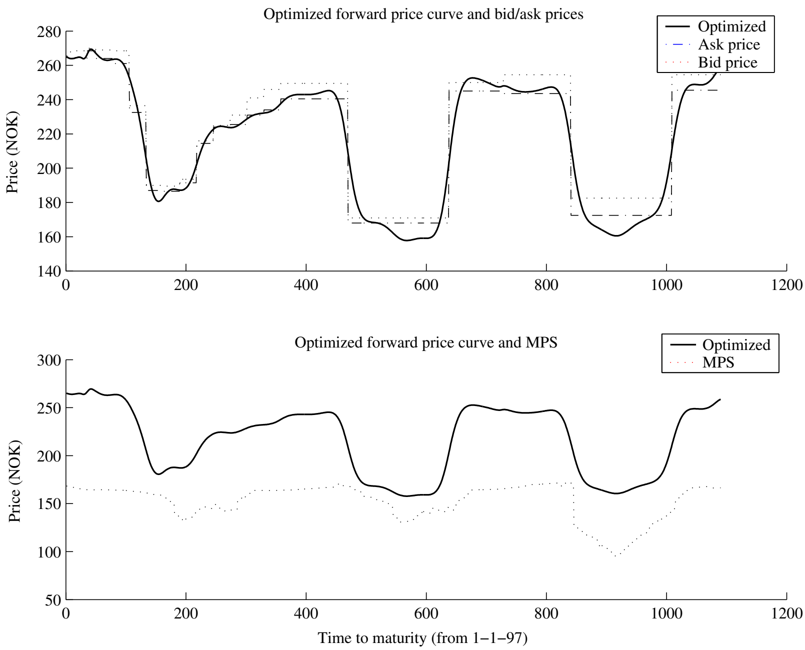

Figure 2.1: Fitting a smooth high resolution forward price curve through a combination of market data and expected price scenarios from the MPS bottom-up model.

In relation to the description of electricity price modelling one can note that this approach is similar to the suggested combined approach for spot price modelling where the scenarios in the spot price model are calibrated to market data to ensure that the expected prices match the forward market prices. This approach indicates that it is possible to use price and hence profit for risk management rather than value without violating the basic criteria of value maximization.

Let f_t denote the price[5] of a forward contract with delivery during a

[5] At the time of writing there is no cash-flow outlay from either buyer or seller of a forward contract so in this context price will refer to the settlement price written in the forward contract.

single hour t and let $F(T_1, T_2)$ be the price of a block forward contract with delivery in the interval $[T_1, T_2]$. With this notation we can define the arbitrage relation between the products as follows (Bjerksund et al. (2000)):

$$F(T_1, T_2) = \frac{1}{\sum_{t=T_1}^{T_2} e^{-rt}} \sum_{t=T_1}^{T_2} e^{-rt} f_t \tag{2.1}$$

The block forward price $F(T_1, T_2)$ is calculated as a weighted average of a series of forward prices f_t over the interval $[T_1, T_2]$. Since we do not observe exact prices but rather a bid/ask spread in the market the equality condition should be replaced by the following:

$$F(T_1, T_2)_{bid} \leq \frac{1}{\sum_{t=T_1}^{T_2} e^{-rt}} \sum_{t=T_1}^{T_2} e^{-rt} f_t \leq F(T_1, T_2)_{ask} \tag{2.2}$$

Notice that the arbitrage bands are not between spot and forward prices but rather between a block forward and the hourly forwards within that block. The arbitrage argument is based on storability and can be used to relate the block forwards to sub-period blocks only because both products are storable. The arbitrage argument states that if cash can be borrowed or invested over time at a rate r then the cash-flows of a block forward contract can be replicated by a portfolio of hourly forward contracts and a cash-flow account. The cash-flow account is used to eliminate the differences in hourly cash-flows between the block contract and the portfolio of hourly contracts. If F is larger than the righthand side of equation 2.2 then an arbitrage profit can be made by buying the hourly forwards, selling the block and using the cash-flow account to replicate cash-flows differences between the two. Similar and arbitrage profit is made by selling the hourly forwards and buying the block if F is smaller than the righthand side of equation 2.2.

The general arbitrage relation for storable commodities can be written as:

$$F(T_0, T_1) = S(T_0)(1 + r)^{T_1} + CY + SC \tag{2.3}$$

where S is the spot price, r is the interest rate, SC represents storage costs and CY is the convenience yield describing any potential benefits from holding the physical commodity in storage rather than the forward contract. This type of arbitrage argument brakes down in real time electricity markets, because electricity cannot be stored in any economically viable manner. Hydro power can to some extent provide a means of storage for producers, however it is limited by the production capacity of the plant (Skantze & Ilic (2001)) and the annual planning cycle of reservoir filling.

In Gjolberg & Johnsen (2001) a spot-futures price relation for hydro producers is provided:

$$F(T_0, T_1) = S(T_0)(1+r)^{T_1} + CY + P(R_l(T_1) > R_{cap})E[S(T_1)] \quad (2.4)$$

Where in the final term on the right hand side P denotes probability, R_l is the reservoir level at time T_0 and R_{cap} is the maximum reservoir capacity. The term can be seen as the storage costs for hydro power. It is the probability of a spill at time T_1 times the expected value of power at time T_1. At low reservoir levels this term is close to zero whereas it equals the expected spot price when reservoir is full and water is spilled. The second term is the convenience yield, which depends on the risk of running the reservoir dry. Again this a term that depends on the expected future spot price, because running dry implies a financial loss that depends on the difference between the prices that occur in period when the reservoir is empty and the prices that prevailed when the water used to sell power in the market.

The literature on forward pricing is centered around two main theories describing the relationship between spot and forward prices. The first approach is based on the arbitrage theory expressed in equation 2.2 whereas the second approach focus on the relationship between the forward price and the expected future spot price. If an investor is risk neutral he should be indifferent between a bet that provides a price $F(T_0, T_1)$ with certainty and any uncertain bet that has an expected price equal to $F(T_0, T_1)$. Any deviation between the two terms $F(T_0, T_1)$ and $E[S(T_1)]$ can therefore be seen as a risk premium RP required by the market as an aggregate. In mathematical notation we can write:

$$F(T_0, T_1) = E_{T_0}[S(T_1)](1+r)^{T_1} + RP \quad (2.5)$$

Justification for a non-zero risk premium can be found in the relationship between hedgers and speculators on the supply and demand side of the market. Speculators demand a risk premium whereas hedgers are willing to pay a risk premium. If there are more hedgers on the supply side then forwards will tend to sell above the expected spot price and vice versa. Paper E in this thesis uses this type of argument to analyze the potential sign of risk premiums in a market for tradable green certificates in a market where the supply side consists mainly of wind turbines.

Audun, Arnob & Marija (2002) examines the expected value theory of the spot-futures price relationship for the Nordic electricity market and finds empirical evidence for a significant negative risk premium during the period 1996 to 2001. These results are however strongly influenced by the hydrological conditions during the period. As an example the year 2000 was a very wet year with a low annual average price. If the futures price is an unbiased estimate of future prices, then it should have overestimated the realized spot price in 2000 as result of the realized hydrological conditions rather than because of a negative risk premium as would be suggested by equation 2.5. To make valid conclusions about the market risk premium and the expected value hypothesis the sample must reflect the distribution of annual hydrological conditions in the Nordic market i.e. the distribution of wet vs. dry years. The six year sample used in the study does not seem to satisfy this requirement.

With respect to short-term contracts Audun et al. (2002) finds a significant negative risk premium and suggests asymmetric short-term flexibility on the supply and demand side (demand less flexible) as a possible explanation. Gjolberg & Johnsen (2001) works with approximately the same data set and attribute similar findings to informational inefficiencies in the market. The fact that hydro producers tend to use fundamental models that do not include price information from the market is suggested as a possible explanation.

Longstaff & Wang (2002) examines the expected value relation in equation 2.5 on day-ahead forward price data from the PJM market in the US. Examining percentage risk premiums for each of 24 hourly day-ahead forward contracts he finds jointly significant average risk premiums. The positive risk premiums are however a result of positive skewness in the hourly spot price distributions due to large price spikes and the medians of hourly risk premiums are therefore generally negative. The study concludes that the forward premium represents compensation for bearing the risk of rare catastrophic shocks in electricity prices.

The key lesson from this section is that electricity risk managers should maximize the value of the firm rather than the expected profit to avoid accidental speculation against the market. As we illustrate in the following section, this does not mean that risk management should necessarily focus on the value distributions rather than profit distributions. Market data is limited in electricity markets and the effect of factors such as transaction costs, volume risk and lack of liquidity are generally not priced in the market. To capture such effects the electricity risk manager must resort to profit/loss distributions. This does not however contradict with the marking to market principle or the maximization of shareholder value criterion as long as profit distributions are calibrated to all sufficiently liquid market data.

2.2.4 Risk measures and modelling framework

In a financial risk management context, risk measures are used to assist in the ranking of choices by translating profit/loss distributions into comparable units. The most prominent example of such a unit is the concept of utility put forth by Neumann & Morgenstern (1953) through a famous set of axioms. If a risk manager accepts these axioms, then consistent and rational decisions must be based on expected utility maximization.

The utility theory requires that the decision maker can express his utility function, which is often problematic. Some basic guidelines can generally be accepted e.g. $\partial U(x)/\partial x \geq 0$ (increasing i.e. more is preferred to less) and $\partial^2 U(x)/\partial x^2 \leq 0$ (concave i.e. risk aversion), but the functional form and exact parameter values of a utility function are generally not easily estimated. One possible approach is to deduce the utility function through the previous actions of a decision maker. However, the data required for such a process is extensive and practical applications are limited by the lack of sufficient data material.

The concept of stochastic dominance can be used to compare density functions and hence eliminate the need to explicitly estimate the specific form of a utility function. Let $G(x)$ and $F(x)$ be distribution functions defined on the closed interval $[a, b]$. $F(x)$ is said to stochastically first order dominate $G(x)$ if $F(x) \leq G(x)\ \forall x \in [a, b]$. Furthermore $F(x)$ stochastically second order dominate $G(x)$ if the area under $F(x)$ is less than or equal to the area under $G(x)$ for all x between a and b, i.e.

$\int_a^u F(x)dx \leq \int_a^u G(x)dx \; \forall u \in [a,b]$. Second order stochastic dominance (SSD) is a necessary and sufficient condition for expected utility maximization provided that investors have increasing concave utility functions (Yoshiba & Yamai (2001)). A drawback with the stochastic dominance concept is that it only provides a partial ordering of density functions. Not all density functions can be ranked according to stochastic dominance and the concept also fails to provide an absolute measure of risk (Guthoff (1997)).

In our definition of risk management modelling we defined a two-fold objective as the location of an optimal trading strategy and reporting of risk to stakeholders. Neither utility functions nor stochastic dominance provide the decision maker with a measure that fulfil both of these objectives by ranking all portfolio combinations and reporting risk to shareholders in a satisfactory manner. Practitioners and academics have therefore turned attention towards more simple indices such as the "At Risk" measures. The original Value at Risk measure VaR_α that has become an industry standard in the financial sector is defined simply as a percentile of a value distribution for a given portfolio over a given time horizon. This definition includes three parameters; a percentile α, the value related to that percentile VaR_α and a time horizon ΔT:

$$VaR_\alpha = sup\{x|F(x) \leq \alpha\} \tag{2.6}$$

where $F(x)$ is the cumulative distribution function of a profit variable x.

Though VaR may seem like an extremely simple risk measure the calculation behind VaR and the analyzes of its theoretical properties are relatively complex tasks. The three basic approaches for calculating VaR are the Variance-Covariance approach, historical simulation and Monte Carlo-simulation (Ku (2001)). Recently a fourth approach based on Extreme Value Theory (EVT) have gained momentum as a tool for improved modelling of tail behavior in the distribution. Recent references to applications of the EVT approach in energy markets include Bystrom (2001) who applies extreme value theory to Nord Pool spot price return series pre-filtered by an AR-GARCH model and Khindanova & Atakhanova (2002) who compare VaR estimates of oil, gas and electricity prices based on normal and stable distributions. An introduction to these four approaches for VaR calculation and an empirical comparison can be found in Gencay & Selcuk (2002).

With respect to theoretical properties Artzner (1999) has provided a set of axioms for risk measures. These axioms establish a framework for analyzing risk measures and as exemplified in Acerbi & Tasche (2001) risk measures that fail these axioms give lead to perverse incentives for risk managers and paradoxical solutions to decision problems.

Given a risky portfolio Z a risk measure $\rho(Z)$ is said to be coherent if it satisfies the following four properties:

- Translational invariance : $\rho(Z + c) = \rho(Z) + c$ for constant $c \in \Re$
- Subadditivity : $\rho(Z_1 + Z_2) \leq \rho(Z_1) + \rho(Z_2)$
- Positive homogeneity : $\rho(bZ) = b\rho(Z)$ for constant $b \in \Re^+$
- Monotonicity : $\forall Z, Y$ with $Z \leq Y$, we have $\rho(Z) \leq \rho(Y)$

Translational invariance: This property implies that by adding an amount c of cash to the initial portfolio and investing it in a risk free account, the risk measure will be decreased by c (when measured as a loss). This property establishes the risk free cash account as a reference for the comparison of risky portfolios.

Subadditivity: The subadditivity implies that the risk of a portfolio is at most equal to the sum of the separate risks of any set of subset of portfolios. It relates to the key concept of diversification in risk management by expressing that portfolio diversification cannot lead to an increase of the risk measure. It also implies that mergers cannot increase risk. If this property did not hold for a risk measure, investors could decrease risk by splitting trading operations into separate smaller units. The subadditivity is therefore essential for risk regulation as a measure without this property would tend to underestimate the aggregate market risk.

Positive homogeneity: This property implies that the risk of a position is directly proportional to its size i.e. n small positions of size m have the same risk as one large position of size nm. If this property did not hold individual companies could decrease their risk measure by splitting or merging portfolios into identical artificial legal units.

Monotonicity: This property implies that if a portfolio has systematically lower returns than another portfolio then it must be more risky.

In a Gaussian world risk is fully described by the variance, which is a subadditive measure. Risk measures including VaR are therefore proportional to the variance in a Gaussian setting and hence subadditive (Acerbia, Nordio & Sirtori (2001)). VaR is however generally not subadditive in a non-Gaussian setting and is therefore not a coherent risk measure when applied to the non-Gaussian distributions observed in electricity risk management problems.

The Conditional Value at Risk (CVaR) or Expected Shortfall (ES) measure has been proposed by Artzner (1999) and multiple others as a coherent substitute for VaR. VaR focusses on the number of times a threshold is exceeded, but is unaffected by the actual size of the losses beyond the threshold. CVaR focus on the average loss in the tail and is hence sensitive to both the probability and the size of a loss beyond the threshold.

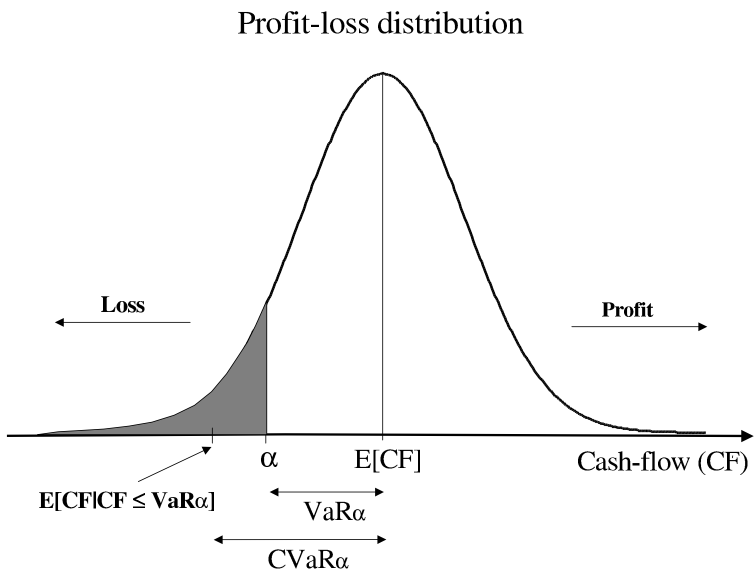

Figure 2.2: Illustration of the VaR and CVaR measures.

CVaR was originally used to express the average loss in the α tail of a distribution (see figure 2.2). For continuous distributions this definition is relatively straightforward and can be written as:

$$ES_\alpha(x) = -E[x|x \leq VaR_\alpha] \tag{2.7}$$

Where x is a profit variable i.e. negative x indicates a loss. For discrete distributions the definition becomes more subtle and this has unfortunately lead to some confusion in the terminology. Acerbi & Tasche (2002) provides a distinction between Tail Conditional Expectation (TCE), Worst Conditional Expectation (WCE) and Expected Shortfall (ES). In most literature expected shortfall is associated with equation 2.7, however by the more exact definitions of Acerbi & Tasche (2002) the two measures are different. To minimize confusion we prefer the notation used in Rockafeller & Uryasev (2002) where CVaR describes the average loss in the α-tail distribution defined as:

$$F_\alpha(x) = \begin{cases} 0 & \forall x > VaR_\alpha \\ [F(x) - \alpha]/[1-\alpha] & \forall x \leq VaR_\alpha \end{cases} \tag{2.8}$$

For distributions with discontinuities at the VaR threshold the definition of the CVaR measure is expanded with CVaR$^+$ and CVaR$^-$, which are defined by substituting α in equation 2.8 with α^+ and α^- respectively. Figure 2.3 illustrates the definition of α^+, α^+ and α respectively, for a discontinuous distribution function $F(x)$.

With this specification CVaR is a coherent risk measure under general conditions. In relation to other terminology CVaR$^+$ is often referred to as the mean shortfall whereas CVaR$^-$ is known as the tail-VaR. Strengths and weaknesses of VaR and CVaR are summarized in table 2.1 from analyzes in Yamai & Yoshiba (2002), Guthoff (1997), Rockafeller & Uryasev (2000) and Yoshiba & Yamai (2001)

Strength/Weakness	VaR	CVaR
Coherent risk measure	-	+
Easily subjected to backtesting	+	-
Related to firms default probability	+	-
Considers losses beyond VaR	-	+
Easily applicable to portfolio optimization	-	+
Consistent with SSD	-	+

Table 2.1: Strengths (+) and weaknesses (-) of the VaR and CVaR risk measures

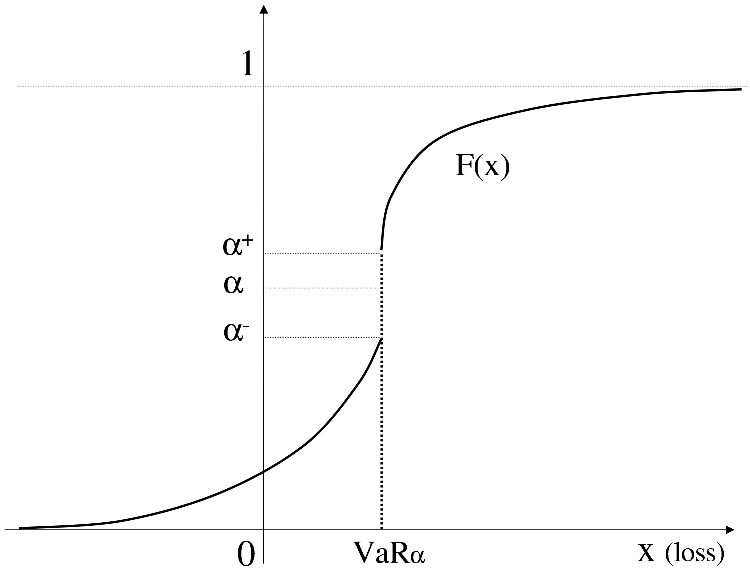

Figure 2.3: Illustration of α^+, α^+ and α for a discontinuous distribution function.

Emerging literature seems to favor the CVaR measure especially for use at the regulatory level. Jaschke (2001) argues that the main argument for bank regulation with CVaR rather than VaR lies with the fact that the main objective of regulatory supervision is to prevent costly bankruptcies. Since the Value at Risk measure is indifferent to losses above the VaR level, it leads investors towards strategies that promise a relatively high expected return, but contain the probability (typically very small) of very large losses. When the objective of regulation is to avoid bankruptcies such an effect this is clearly undesirable (Jaschke (2001)) and (Yamai & Yoshiba (2002)).

Artzner (1999) note that both VaR and CVaR leave out valuable information both about losses below (smaller losses) the VaR threshold level and about higher moments of losses above (larger losses) the threshold. To alleviate this problem Wang (2002) suggests a family of coherent risk measures based on probability distortions that employ the whole loss distribution[6].

With respect to the suitability of risk measures in electricity markets we note that the objectives of risk management are similar to those found in financial markets. The cost of bankruptcies and financial distress are main arguments for hedging both with respect to the corporate perspective and the regulatory perspective. Currently there is no regulation of electricity companies, however given the essential role of electricity based services in society such regulation could be warranted if future speculative bankruptcies threaten the security of supply. The application of of CVaR in electricity markets is therefore an obvious area for future empirical applied research.

Profit vs. Value: Although the objective of both risk regulation and company specific risk management are similar in electricity markets and financial markets, the appropriate unit for risk measurement is different. Banks and insurance companies need to invest their funds, but the profitability of these investments are generally dependent on the companies core business i.e. the sale of insurance of bank accounts. The financial markets are furthermore highly liquid and investments can generally be liquidated at a short notice without significant transaction costs. In such an environment value is the relevant measure for risk, because it reflects the cash-flow that could be realized to meet obligations by selling the portfolio.

The situation is different for electricity companies. Investments in generation plants, manpower or other forms of equipment are investments that are part of the companies core business. Such assets cannot simply be replaced by other assets because their profitability arises as a result of company know how. Furthermore assets such as power plants are generally not traded in the market and the position cannot be liquidated at a short notice without considerable costs. Market value is a less useful unit for risk management in such an environment since it no longer represents the cash-flow that could be realized by selling the portfolio.

Volume risk and liquidity risk are described in Henney & Keers (1998) as the primary factors that affect value without being priced by the

[6] A distorted probability distribution is simply a function g(F(x)) of the original distribution function F(x) mapping percentiles to reals.

market. Volume risk occurs due to forced outages and demand swings which are highly correlated with the wholesale spot price. Liquidity risk occurs because companies cannot replicate their physical assets with sufficiently liquid derivatives on a continuous basis. As an illustrative example we consider again the financial replication of a thermal power plant through a series of spark spread options. An analytical formula for the spark spread option for a future time period T based on forward contract replication was provided by Deng et al. (2001):

$$C(t,T) = e^{-r(T-t)}\left[F_e(t,T)N(d_1) - HR\,F_g(t,T)N(d_2)\right] \tag{2.9}$$

$$d_1 = \frac{ln\left(\frac{F_e(t,T)}{HR\,F_g(t,T)}\right) + \frac{\sigma_s^2(T-t)}{2}}{\sigma_s\sqrt{T-t}}$$

$$d_2 = d_1 - \sigma_s\sqrt{T-t}$$

$$\sigma_s^2 = \frac{\int_t^T(\sigma_e^2(s) + \sigma_g^2(s) - 2\rho_{eg}(s)\sigma_e(s)\sigma_g(s)ds}{T-t}$$

Where $F_e(t,T)$ and $F_g(t,T)$ are forward prices at time t for the period T of electricity and natural gas respectively, $\sigma_e^2(s)$ and $\sigma_g^2(s)$ are the variance for a contract with maturity s for electricity and natural gas respectively, $\sigma_s^2(s)$ is the total spark spread variance, ρ is the linear correlation coefficient between electricity and natural gas for maturity s, HR is the heat rate and r is the risk free interest rate. The use of forward contracts is made necessary by the non-storable nature of electricity, which prevents replication strategies based on borrowing and storage of electricity.

This analytical spark spread formula represents a highly stylized description of a power plant that fails to take a series of important factors into account. First of all it is based on the assumption that forward prices are accurately described by a normal distribution. Numerous empirical studies including Johnson & Barz (2000), De Jong & Huisman (2003) and Joy (2000) indicate that this is not the case in electricity markets.

Denton (2003) that current state of the art analytical models fail to take operational limitations such as rate limits, start up costs and non-linear heat rate characteristics into account. Analytical approaches also fail to include volume risk and liquidity risk. Although it might be possible to replicate a power plant at time t_1 for some future time interval $[t_3; t_4]$ using the relevant futures contracts on electricity and gas, there is no guarantee that the market will be sufficiently liquid to allow for an accurate rebalancing of this portfolio at t_2. Furthermore there is no analytical way of including volume risk unless a liquid insurance market for this specific type of risk exists.

A series of risk measures based on cash-flow rather than value have been suggested for electricity companies. These measure have different names such as Profit at Risk (PaR), Earnings at Risk (EaR) and Cash-Flow at Risk (CFaR), however they all focus on the fact that cash-flow is a more relevant variable for electricity market risk management than value (Ku (2001)). By using these measures in a discrete state space framework solved by dynamic programming techniques as described in Denton (2003) one can include the factors listed above. When the scenario tree is made consistent with the value maximization criterion by calibrating expected profit scenarios to forward market prices PaR can be seen as an extension of VaR. All the market data that would be used to calculate VaR is included, but the information set is expanded to include the factors not priced by the market.

Paper B in this thesis discusses the use of the PaR measure and examines how the PaR measure is affected by the modelling of various parameters such as volume risk and price spikes for a simple risk management problem of an electricity generator.

Simulation vs. Optimization: A basic classification in mathematical modelling is the distinction between normative models and descriptive models. The two main objectives of risk management lead to a similar distinction between optimization models and simulation models. Optimization models are normative and directed towards the location of a strategy based on some criteria of optimality and a set of constraints. In risk management the optimization will typically involve the location of a portfolio that maximizes profit in the face of risk constraints or minimizes risk subject to constraints on the expected profit. Simulation models are descriptive and are typically used to report the risk of a companies portfolio either internally or to stakeholders. If risk limits are exceeded action can then be taken based on more qualitative analysis or a subsequent run with either an optimization model or a simulation models with different parameters.

Value at Risk and Conditional Value at Risk are generally expressed as risk limits. In simulation models the measures are derived from the set of scenarios used and can be directly compared to the predefined limits. The advantages of simulation is that many parameters and scenarios can be included to give a detailed representation of both the size and dependencies between risk factors. We can thus get an accurate measure of PaR or VaR for a specific portfolio. The main drawback is of course that simulation does not provide information about the optimal portfolio or strategy. Optimization models allow for a comparison of different portfolio combinations or strategies, but the mathematical complexity constrains the number of parameters and scenarios and hence the accuracy by which the risk measures can be calculated.

Optimization with Value at Risk is made particularly difficult by the non-linear and non-convex nature of the risk measure (Gaivoronski & Pflug (2001)), (Rockafeller & Uryasev (2000)). If input factors are modelled by analytical distributions then VaR can for special cases be calculated analytically. Such analytical models are however generally highly constrained in terms of distributional assumptions and tend to lack the flexibility required to model all relevant parameters for electricity risk management.

Discrete scenario tree approaches based on stochastic programming and dynamic programming principles represent the primary alternatives to analytical models. VaR is however mathematically problematic in such models as it leads to integer or mixed integer programming problems. Contrary to VaR optimization problems it is shown in Rockafeller & Uryasev (2000) that CVaR optimization can be solved as a Linear Programming (LP) problem. The LP approach is expanded to handle discrete distributions where jumps occur at the VaR threshold and optimization problems with CVaR constraints in Rockafeller & Uryasev (2002) and Krokhmal, Palmquist & Uryasev (2002). A key aspect of the approach is that CVaR can be optimized without an explicit calculation of VaR. Furthermore one will always obtain a solution with a conservative VaR since CVaR $\geq$ VaR by definition (see figure 2.2). The LP feature of CVaR optimization makes CVaR suitable for discrete state space approaches, where the size of the discrete scenario tree tends to be the main limiting factor with respect to tractability.

The author is not aware of any literature applying CVaR or VaR optimization to electricity risk management problems. Taking into account the size of losses beyond a VaR level is however equally relevant for electricity generators and retailers as for financial companies and applications of profit based versions of the CVaR measure is therefore an obvious future development for electricity market risk management.

Paper B in the thesis examines a simple PaR optimization problem where a generator attempts to hedge a long call option on electricity using a short forward position. By looking at payoff diagrams of the combined portfolio the paper illustrates that PaR is a convex function of the forward hedge used as decision variable. Results of this type can be used to create solution algorithms and an analytical analysis of payoff diagrams can therefore help increase the size of PaR problems, which can be solved to optimality.

2.3 Concluding remarks

This chapter has reviewed basic risk management theory and recent literature addressing problems specific to risk management in the electricity sector. The chapter has also explained how the research papers A and B have contributed to research in this area and have indicated directions for future research.

Chapter 3

Investments in generation capacity and security of supply

One of the primary benefits from liberalization and the introduction of real-time pricing is a potential reduction in the amount of production capacity. This expected reduction is based on an increased demand flexibility and more scrutiny in the investment decisions in a system where market participants are exposed directly to real-time prices and the financial consequences of their decisions. The potential gain will depend on the market's ability to outperform regulators by providing incentives to investors that more accurately reflect the preferences of consumers.

Electricity is a private good in its quantity dimension. This implies that property rights for a unit of electricity can be assigned to an individual consumer and once consumed the unit cannot be consumed by others. Electricity is not valued by consumers solely through its quantitative dimension, but rather through the services that it provides. Most electricity dependent services are based on a preceding planning process where a stable supply of electricity is assumed available at request. This implies that electricity is also valued by consumers through a quality dimension[1] in terms of supply security.

Proponents of liberalization have long argued that regulation has lead to overcapacity due to a one sided focus on reliability at the expense of economic efficiency. The market price signal must provide incentives for new investments in a liberalized market and the key question is therefore whether or not market prices will be able to more accurately reflect consumer preferences in terms of both security of supply and economic efficiency. The shift in the investment decision making process from regulators to private investors have placed new demands on those decision makers that are affected by the electricity price. This chapter reviews the consequences of this shift from three different perspectives:

1. The individual investor perspective: How are investment decisions made in a liberalized electricity market?
2. The market perspective: How can models of market equilibrium be adapted to fit the characteristics of a liberalized setting?
3. The regulators perspective: How will different models for regulation of the capacity balance affect security of supply and economic efficiency in the long term?

3.1 The investor perspective

The papers of this thesis that deal with investments in generation capacity (C,D and E), focus mainly on market modelling and the perspective of the regulator. The individual investor's perspective is reviewed in this section, because it introduces some basic aspects of theory that are required to properly analyze market equilibrium models and models for regulation of the capacity balance. For a more elaborate analysis of the investor perspective the reader is referred to Murto (2003) or Deng (1999).

[1] Environmental aspects can be seen as an additional component of the quality dimension, however the issue of regulation in this area is an elaborate topic in itself and is considered outside the scope of this thesis.

Traditional investment theory based on the Net Present Value (NPV) framework values an investment opportunity as the sum of expected future cash-flows discounted for the time value of money and possible also the effect of risk. In an uncertain environment management will however often have the ability to react to new information as it arrives over time and hence optimize the timing of its decisions. Modern investment theory recognizes that such flexibility creates a non-negative option value and that traditional approaches that fail to incorporate such effects tend to underestimate project value (Trigeorgis (1995)).

The distinction between risk adjustment and the value of flexibility is fundamental in investment theory. Both aspects depend on the level of uncertainty, but typically in reverse directions. Investors are generally assumed to be risk averse implying that increased uncertainty will decrease project value. The option value of flexibility[2] is a non-decreasing function of the volatility and uncertainty will therefore not necessarily have a negative effect on project value. The effect is ambiguous with a sign that depends on the tradeoff between the effect of risk version and managerial flexibility.

The two main techniques used for valuation in modern investment theory are contingent claim analysis and dynamic programming (Dixit & Pindyck (1994)). Contingent claim analysis is based on the arbitrage principle where a non-traded project is valued as the present value (discounted for time value of money at the risk free rate of return) of a portfolio of traded assets that exactly matches the cash-flow of the project in all stages and potential states. If such a replicating portfolio exists the market is said to be complete and the contingent claim analysis provides both a value and a replicating strategy for the investment problem (Smith & Nau (1995)). The dynamic programming approach does not require the existence of a complete market and includes the investor's subjective valuation of risk either by discounting cash-flows at a risk adjusted rate or by using a utility function as the objective.

In complete markets it is possible to separate the investment decision and the financing decision. When the dynamic programming approach is formulated as a decision tree approach with a utility function repre-

[2] Seen as the difference between the values of a project with and without the optionality (Wallace (1999)).

senting the subjective level of risk aversion, it provides the same project value and replicating strategy as the contingent approach regardless of the utility function used. The solution to the investment problem is therefore identical to the solution sound by a contingent claim approach, however in return for the additional input provided the dynamic programming also calculates an optimal strategy for the financing decision (Smith & Nau (1995)). The ability to separate the financing and investment decision breaks down in incomplete markets where all risks of a project cannot be replicated. In this case contingent claim analysis can only produce upper and lower bounds on the project value with intervals that depend on the amount of risk that can be hedged in the market.

Project risks related to electricity and fuel prices can to some extent be hedged in Nordic electricity market through a portfolio of forward contracts. A series of papers have used the forward based replication strategy presented in Deng et al. (2001) to value power plants, based on the assumption that the investment is affected only by these two factors (see e.g. Frayer & Ulundere (2001) or Hsu (1998)). Examples of more detailed contingent claim applications include Fleten et al. (2003) who calculates the value of gas fired power plants with CO_2 capture facilities taking while into account the option values of operating flexibility and the ability to postpone the investment. Murto (2003) examines the effect of input fuels uncertainty on the optimal timing of an irreversible investment choice between either a fossil fuel fired plant or a biomass fired plant.

Finally, Deng (2000) and Deng & Oren (2003) introduce a contingent claim based framework for pricing of electricity derivatives based on an underlying spot price process that can include factors such as mean-reversion, seasonality, spikes or jumps. Although it is not explicitly stated in the two papers, the market for such risks is not complete, and the formulas are therefore based on the assumption of risk neutral investors. Market completeness is not a general characteristic that can be attributed to a market, but rather a concept that must be evaluated for each specific project. The electricity market might be considered complete for some investment opportunities and incomplete for other depending on whether or not cash-flows can be replicated in all future states and stages.

The risk factors that affect the cash-flow stream generated by a power plant were reviewed in detail in Chapter 2 and can be classified as either price risk, volume risk and cost risk. For valuation it is generally not sufficient that these risk factors can be hedged using financial assets in the market, because real assets such as power plants are associated with transaction costs and technical constraints that change the cash-flow stream compared to a financial portfolio. Examples of technical constraints that can affect the flexibility value and operation costs of a gas fired power plant include: Hourly minimum and maximum operating ranges, Limitations on ramp rates, Cycle times constraints, Maximum number of cycles during a period, Startup and shutdown times and costs, Relationship between heat rate and output level (Dorris & Dunn (1999)).

Models that fail to incorporate technical constraints into the valuation procedure will tend to over estimate the value of investment projects in empirical applications (Denton (2003)). Deng (2003) use a trinomial tree solved by backward dynamic programming to incorporate operational characteristic such as startup/shut-down costs, ramp-up times and output dependent heat-rate into the real option valuation of a power plant. Denton (2003) describes a similar approach, but notes that the methodology requires the assumption of risk neutrality. Deng & Oren (2003) expands the framework to account for price spikes in the spot price process by using the analytical formulas derived in Deng (2000). Although these methods are based on dynamic programming they avoid the issue of subjective risk preferences through the assumption of risk neutrality.

When the market is incomplete and investors are risk averse the model must include information about subjective risk preferences. To model the investment decision in such a setting Siddiqi (2000) use a decision tree approach where a utility function describes the investor's subjective risk preference. The arguments proposed in chapter 1 against the use utility functions for risk management can however be transferred to the case of investment decisions. Long-term investments in production capacity should enter into the firms general risk management framework and Value at Risk based measures would therefore be more appropriate for modelling of the firm's risk preferences. A series of NPV based methods termed CFaR, PVaR and RPV, have been suggested for this purpose (Shimko (2001)).

Assuming a setup with two time periods, the Cash Flow at Risk method (CFaR)[3] calculates a certainty equivalent by subtracting a risk charge for risk capital (defined as losses exceeding the VaR measure) at each time step:

$$V_{CFaR} = \frac{\mu_1 - kz\sigma_1}{1+r} + \frac{\mu_2 - kz\sigma_2}{(1+r)^2} \tag{3.1}$$

$$= NPV - z\left(\frac{\sigma_1}{1+r} + \frac{\sigma_2}{(1+r)^2}\right) \tag{3.2}$$

V_{CFaR} represents the present value computed with the CFaR approach, μ_t is the expected cash-flow at time t, σ_t is the standard deviation of cash-flows at time t, and z_t is the number of standard deviations used to define risk capital[4] and the parameter k is a risk charge expressing the investor's level of risk aversion. The CFaR approach neglects correlations between the cash-flows in different time steps ρ_{12}. The Present Value at Risk (PVaR) approach includes the effect of correlation by delaying the risk adjustment until after the discounting of cash-flows:

$$V_{PVaR} = NPV - kz\left(\frac{\sigma_1^2}{(1+r)^2} + \frac{2\rho_{12}\sigma_1\sigma_2}{(1+r)^3} + \frac{\sigma_2^2}{(1+r)^4}\right)^{1/2} \tag{3.3}$$

If cash flows are uncorrelated between time steps then the two measures CFaR and PVaR are identical.

Shimko (2001) expands the methodology by including the effect that arises as uncertainty is resolved over time. For the two period example this implies that if some uncertainty about period 2 cash-flows is resolved during periods 1, then this should be reflected in the valuation. Technically this implies discounting a larger amount of risk capital in the first year and a smaller amount in the second year. The approach is termed

[3] The CFaR approach described here should not be confused with the VaR measures discussed in chapter 2 although the terminology might coincide.

[4] This simplified example assumes that cash-flows follow a distribution, such as the Gaussian, completely defined by the first two moments.

Risk-adjusted Present Value (RPV) and takes the following form:

$$V_{RPV} = NPV - k^* z \left(\frac{\Sigma_1}{1+r} + \frac{\Sigma_2}{(1+r)^2} \right) \tag{3.4}$$

$$\Sigma_1 = \sigma_1 (1 + \frac{\rho_{12}\sigma_2/\sigma_1}{1+r}) \tag{3.5}$$

$$\Sigma_2 = (\sigma_2^2 - \rho\sigma_2\sigma_1)^{1/2} \tag{3.6}$$

$$k^* = k/(1+r+k). \tag{3.7}$$

The three approaches all share the need for exogenous specification of an investor specific risk aversion parameter k. A key question is therefore whether or not decision makers will be able to specify a k that fits their subjective risk preferences. Furthermore the framework only takes risk and not option values into account. A logical expansion would therefore be to implement the RPV approach in a decision tree context.

3.2 The market perspective

The models described in the previous section assume the electricity price to be an exogenous input parameter. While this may be sufficient from the individual investor's perspective, many decision problems require a description of the interaction between investments and price formation in the market over a long-term perspective.

The different categories for electricity price modelling described in chapter 2 illustrates the diversity in modelling approaches. Models that include technical bottom-up data are often preferable when the objective is to analyze the long-run dependency between investments and prices, rather than modelling of prices alone. Our focus here will be on partial equilibrium models, which estimate equilibrium in the long-run through bottom-up modelling of demand, supply and technical constraints. Partial equilibrium models are based on the same data set used in category 2 models, but provide a flexible framework as they can be expanded to include elements from categories 3, 4 and 6. This section introduces a basic framework for electricity market modelling and describes how factors such as price flexible demand, financial investment risk and dynamic technological improvements can be included into such models.

The lack of economical storage possibilities combined with relatively large periodic and stochastic fluctuations in demand and supply of electricity, place the electricity sector in the extensively treated category of peak-load pricing problems (Crew (1995)). The main part of literature in this field has been developed for regulated systems where demand was assumed to be inelastic. The combination of inelastic demand and stochastic supply and demand creates a potential for involuntary rationing of consumers. The reliability aspect have been extensively treated in the regulated setting with focus on efficient methods for rationing and measurement of outage costs (Doorman (2000)). Crew (1995) reviews an extensive set of references that question the accuracy of methods for measuring outage costs. The main problem is that consumers have a lack of experience with outages and hence the related costs. As with utility functions the problem lies not with the theory as such, but rather with the lack of data and applicability of theory in practice.

The problems with estimation of outage costs and demand elasticity can be seen as an argument for the introduction of markets with real-time pricing, where consumers can express their preferences directly through the markets price. In principle consumers would never pay an infinite price for electricity and voluntary demand reductions should therefore ensure that the market clears at a finite price at all times (Schweppe, Tabors & Bohn (1987)). In such a system there would be no need for any quantity rationing procedure or capacity regulation. However, the speed at which bilateral markets operate prevents demand from reacting to stochastic fluctuations within the time frame (typically a matter of seconds or less) required to avoid fluctuations in frequency and voltage. The transaction costs associated with such near continuous trading will furthermore render such systems economically infeasible.

The potential for situations where demand acts as if it was totally inelastic in real-time, leads to public good issues and hence free rider problems. Such aspects will tend to decrease investments below the optimal level of system capacity and increase the risk of blackouts. The California crisis illustrated that poor market design and an increased risk of blackouts can lead to costly bankruptcies, costly political intervention and hence highly negative effects on the economic efficiency that extend far beyond the direct costs related to involuntary disconnection of consumers.

The implications of potential involuntary disconnection of consumers for regulation and market design are treated in the following section. The focus is kept on how prices and investments are linked through the quantity dimension of electricity and it is therefore implicitly assumed that market prices are the result of equilibrium in a forward market (e.g. a day-ahead market) where demand elasticity is sufficient to ensure a finite market price at all times.

3.2.1 Fixed cost recovery under short-run marginal cost pricing

The issue of fixed cost recovery under marginal cost pricing has been a key controversy particularly in peak load pricing theory (Doorman (2000)). Traditional literature provide different answers depending on the underlying assumptions about factors such as indivisibility of plant size, irreversibility of investments, lead times and forecasting abilities (Andersson & Bohman (1985)).

In a liberalized market with a price elastic demand side, fixed cost recovery can be described by a relatively simple model based on short-run marginal pricing. To explain fixed cost recovery Fraser (2001) use the cost minimization framework known from the regulating sector, but adds price elastic demand as a peak load production unit with no fixed cost. During peak load hours where all available production capacity is in use, the market price is determined by willingness to pay on the demand side. Figure 3.1 illustrates the derivation of the cost minimizing solution[5], which ensures that the revenue from peak load hours exactly cover the fixed costs of the most expensive production technology.

The figure illustrates the cost structure for a set of three technologies $N = \{A, B, C\}$ in terms of fixed costs (FC_n) and variable costs (VC_n). Voluntary demand reductions are included as a production technology (D) with variable costs approximated by a constant average marginal willingness to pay (WTP)[6] and zero fixed costs $FC_D = 0$. The tradi-

[5]The optimization criteria is profit maximization rather than cost minimization in a liberalized market. The two solutions will however coincide in the stylized deterministic and perfectly competitive framework illustrated in Fraser (2001).

[6]This highly simplified modelling of the demand side is improved in the following

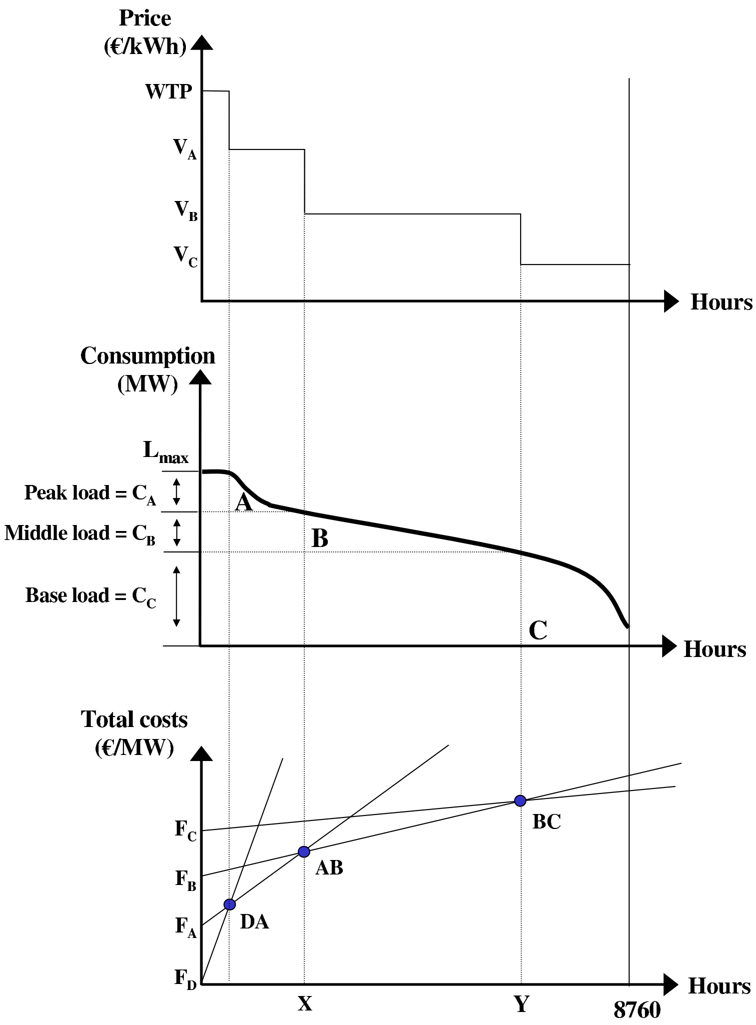

Figure 3.1: Deriving the cost minimizing solution with flexible demand viewed as a peak load unit without fixed costs. L_{max} indicates the maximum load, which equals the amount of production capacity in the system i.e. $C_A + C_B + C_C$.

subsection.

tional approach for cost minimization can now be used to illustrate the optimal amount of capacity (C_n) for each technology and the resulting market prices based on marginal cost pricing. The fact that the price flexible demand side can be viewed as a peak load unit without any fixed costs solves the problem of fixed cost recovery for the most expensive technology.

It is crucial to understand that it is not just the peak load production technology that is dependent on revenue for fixed cost recovery during the peak load hours where the market price is determined by consumers WTP. All technologies will exactly recover their fixed costs in an optimal long run equilibrium. Although a base load plant will recover a smaller part of its fixed costs during these critical hours in relative terms, it will recover a a larger amount in absolute terms. This observation is used extensively in paper D where a framework for inclusion of risk in partial equilibrium models is provided.

The pricing mechanism illustrated above is static and ignores the potential for technological developments in the cost structure of production units. In a more dynamic formulation the total average marginal cost would depend on the age of the production technology due to wear and tear. Furthermore, the marginal cost of new investments would be decreasing as a result of technological improvements. In such a system it is likely that a base-load investment could move down the merit order during the course of its life time and hence serve as a peak load unit during the final years of operation. Though this type of dynamic developments could reduce or even eliminate the need for investments in peak load capacity it does not change the fundamental pricing mechanism illustrated in Figure 1. Peak load hours where all available production capacity is in use must still occur to prevent the units that serve as peak load capacity from being scrapped.

3.2.2 Partial equilibrium models with demand flexibility

Though the approach of Fraser (2001) includes the effect that demand elasticity has on prices during peak load hours, it does so based on a predefined load duration curve. This leads to inconsistencies because of the circular relation between prices, investments and demand response illustrated in Figure 3.2. Price formation in the market will affect the load duration curve when demand is price elastic. The load duration curve will affect the structure of the optimal capacity mix, which in turn will affect price formation. The load-duration curve is therefore an endogenous part of the equilibrium and cannot be supplied as an exogenous input.

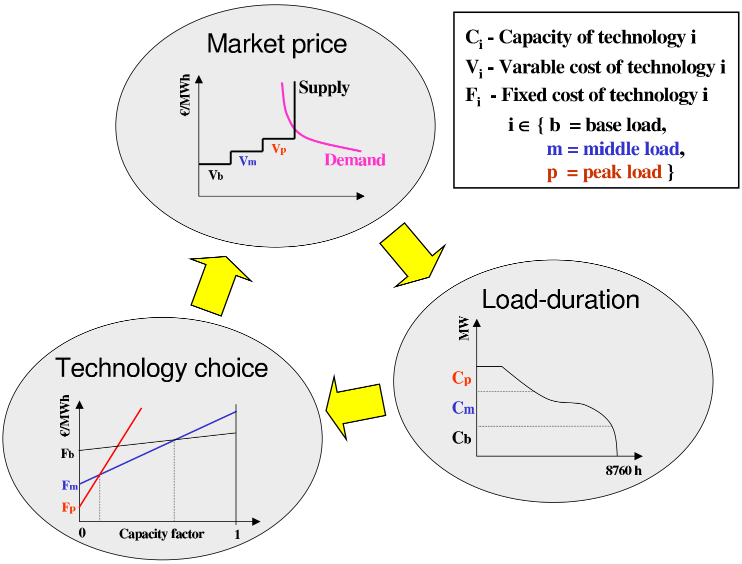

Figure 3.2: Illustration of the circular dependence between load, market prices and technology choice in a liberalized electricity market.

To properly handle demand elasticity, the market model must be based on a set of demand curves reflecting the level and elasticity of demand at each time interval in the model. Figure 3.3 illustrates the structure of such a model for an annual time horizon. In this graphical illustration the decision variable determined by the equilibrium model is the horizontal length of the variable cost plateaus, which reflect the amount of production capacity installed of each type.

Hourly demand curves contain more information and are generally more difficult to estimate than load-duration curves. This type of exogenous demand data is however needed to properly model the equilibrium.

Profit maximization is the correct criteria for investment decisions in a

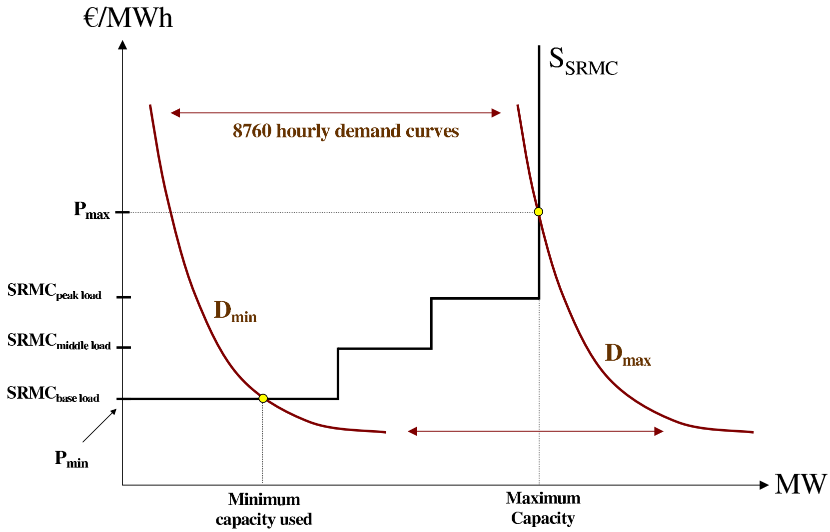

Figure 3.3: Illustration of the range of hourly equilibria in a model with price flexible demand.

liberalized market. The criteria is however difficult to apply in an equilibrium context as it requires that definition of a set of producers that would accurately reflect competition. The use of a single average profit maximizing producer would correspond to maximization of producer surplus, which in turn would yield the monopoly solution.

Assuming that all parameters are deterministic and that the market is characterized by perfect competition there is equivalence between profit maximization and maximization of social surplus i.e. the sum of producer surplus and consumer surplus. This allows the optimization problem to be stated as maximization of social surplus, which makes the modelling less complex. The following equilibrium model describes a market based on short-run marginal costs with hourly prices determined as the intersection between the short run marginal production cost curve and the demand curve represented by marginal utility of consumption i.e. the marginal willingness to pay. A set of increasing concave utility functions

$U^h(d^h)$ are used to model the consumer surplus function[7] whereas the producer surplus function is represented by a set of piecewise linear functions representing the fixed cost components FC and variable costs VC component of each technology i considered.

With maximization of social surplus over a predefined time horizon of H as the objective and production limits and supply/demand balance as primary constraints, we can write the equilibrium model as follows:

Maximize

$$\sum_{h=1}^{H} U^h(d^h) - \quad \left(\sum_{i=1}^{I} \sum_{h=1}^{H} VC_i q_i^h \quad + FC_i Q_i\right)$$

s.t.

$$\begin{array}{lcl} Q_i \geq q_i^h/1h & ; & \forall(h \in H, i \in I) \\ \sum_{h=1}^{H} q_i^h \geq d^h & ; & \forall(h \in H) \\ q_i^h \geq 0 & ; & \forall(h \in H, i \in I) \\ Q_i \geq 0 & ; & \forall(i \in I) \\ d^h \geq 0 & ; & \forall(h \in H) \end{array}$$

where the index $i \in I$ represents the set of individual technologies and $h \in H$ is the set of time steps in hours used in the model.

The following notation is used for parameters and decision variables:

Decision variables
- q_i^h : Amount of power produced by technology i in hour h (MWh)
- Q_i : Capacity of technology i (MW)
- d^h : Quantity consumed during hour h (MWh)

Parameters
- $U(d^h)$: Utility in hour h from consuming the quantity d^h (€)
- VC_i : Variable cost for technology i (€/MWh)
- FC_i : Fixed costs for technology i amortized to the period H[8]

For a more intuitive formulation the problem can be written as a complementary optimization problem with primal-dual constraint pairs representing quantity-price relations. The first order optimization criteria is derived by forming the Lagrangian of the problem, differentiating with respect to each of the decision variables and setting equal to zero.

[7] Utility function can be seen as inverse demand curves in the Walrasian sense.

$$
\begin{aligned}
L = \sum_{h=1}^{H} U^h(d^h) - (\sum_{i=1}^{I}\sum_{h=1}^{H} VC_i q_i^h + FC_i Q_i) \\
- \sum_{i=1}^{I}\sum_{h=1}^{H} pc_i^h (q_i^h/1h - Q_i) - \sum_{h=1}^{H} pm_t (d^t - \sum_{i=1}^{I} q_i^h)
\end{aligned}
\quad (3.8)
$$

$$
\begin{array}{rcccccc}
\frac{\partial L}{\partial d^h} & = & \partial U/\partial(d^h) - pm^h & = & 0 & \forall & h \in H \\
\frac{\partial L}{\partial q_i^h} & = & -VC_i - pc_i^h + pm^h & = & 0 & \forall & i \in I, h \in H \\
\frac{\partial L}{\partial Q_i} & = & -FC_i + \sum_{h=1}^{H} pc_i^h & = & 0 & \forall & i \in I
\end{array}
$$

The non-negative Lagrangian variables (multipliers) pc and pm can be interpreted as shadow prices to each of the primary quantity based constraints in the primal problem. The three optimality conditions derived from the Lagrangian can be seen as primary constraints in the price based dual problem and have the three original decision variables as their dual counterparts. This interpretation yields five primal-dual constraint pairs, which express the relationship between price and quantity in the model.

Demand optimality condition:

$$\partial U/\partial(d^h) - pm^h \geq 0 \quad \forall h \quad (3.9)$$

$$d^h \geq 0 \quad \forall h \quad (3.10)$$

This primal-dual pair states that the market price pm is always defined by the marginal utility of consumption. The two are equal at all positive demand levels and demand is only zero if price is larger than the marginal utility at zero consumption.

Production optimality condition:

$$pm^h - VC_i - pc_i^h \geq 0 \quad \forall h, i \quad (3.11)$$

$$q_i^h \geq 0 \quad \forall h \quad (3.12)$$

This second primal-dual pair states that price can be larger than marginal costs VC for all technologies by an amount equal to pc. Combined with the demand optimality pair above it illustrates that the market price is always determined by marginal utility of demand but can exceed the marginal production costs of all technologies.

Capacity optimality condition:

$$FC_i - \sum_{h=1}^{H} pc_i^h \geq 0 \quad \forall i \tag{3.13}$$

$$Q_i \geq 0 \quad \forall i \tag{3.14}$$

The capacity optimality conditions ensures that the sum of capacity price adders earned by a specific technology over all time intervals must exactly equal its fixed cost. The primal-dual pair states that installed capacity will be positive if the sum of capacity adders (defined by the production optimality constraint as price minus VC) is equal to fixed costs, but zero i.e. no capacity is built, if the sum of capacity adders is less than the fixed costs.

Primal market balance:

$$\sum_{h=1}^{H} q_i^h - d^h \geq 0 \quad \forall h \tag{3.15}$$

$$pm^h \geq 0 \quad \forall h \tag{3.16}$$

The fourth primal/dual constraint pair ensures that the market clears at a positive price if the sum of all production equals demand. Production in excess of demand implies a market price of zero.

Primal capacity constraint:

$$Q_i - q_i^h/1h \geq 0 \quad \forall h, i \tag{3.17}$$

$$pc_i^h \geq 0 \quad \forall h, i \tag{3.18}$$

The final complementary constraint pair states that the capacity price adder pc will be positive if production on technology i during h (measured in energy per hour (MWh/h)) is equal to the capacity limit for technology i. If production is less than the capacity limit pc must be zero.

The model forms the basis for understanding the long-run market equilibrium in electricity markets and the fixed cost recovery of new generation capacity. The following section examines how investment risk can be included into this type of modelling framework.

3.2.3 Including risk into PE models

Section 3.1 illustrated how risk and risk aversion could be modelled when the electricity price can be treated as an exogenous input to the investment problem. Such an assumption is reasonable for the individual investment decisions when a decision maker cannot affect the electricity price through his actions. Modelling the effect of risk becomes significantly more complex in a market setting, where prices must be endogenously determined within the model.

Hazell & Norton (1986) provides a framework for market equilibrium under risk in an agricultural setting. The models are based on stochastic production (yield) and price as the two dependent stochastic variables. Electricity markets with a large share of hydro power will also have supply uncertainty and much of this theory can therefore be used in an electricity market context. Without addressing the details of this framework we note that the derived objective function can be seen as the sum of areas under demand curves based on either expected or actual realized supply functions (depending on price assumptions made by the suppliers) minus the cost of supply including a risk adjustment. The analytical framework shows that social surplus can be used to model profit maximization if the proper adjustments are made for risk.

Paper D introduces a more practically oriented framework for risk inclusion motivated by the need for tractability. Including stochastic parameters in equilibrium models is generally problematic, because it leads to analytically complex and/or large models structures. Incorporation of risk measures is also a source of complexity as these tend to create non-convex models. Hazell & Norton (1986) suggests a mean variance type adjustment and an approach for linearizing the variance term. Linearizing will however involve a tradeoff between accuracy and size and tractability is therefore also problematic in such approaches. Furthermore, one cannot linearized more mathematically complex risk measures such as Value at Risk.

To circumvent these complications paper D introduces a framework based on a separation of the risk adjustment from the equilibrium model. The framework is based on the basic idea that risk aversion can be viewed as a technology specific fixed cost adder. Adding the risk premium to the fixed cost component ensures that there is no conflict with the short-run marginal pricing criteria and hence the assumption of perfect competition. The separation will naturally lead to potential inconsistencies, but the decision maker can choose a tradeoff between inconsistencies and tractability through the level of interaction and shared data between the two modules.

Figure 3.4 illustrates the setup with a partial equilibrium model of the power market and a risk module. The power market model calculates expected prices and optimal investments whereas the risk module translates prices, costs and volumes into risk premiums. Based on the interaction between the input and output from these two modules and the amount of shared data, four levels of consistency have been derived.

The simplest approach is based on a complete separation where the only interaction between the two modules lies with the use of technology specific risk premiums calculated by the risk module as fixed cost adders in the deterministic power market model. The distributions for parameters needed in the risk module including market prices, production volumes and costs are all assumed as exogenous input. This approach has a significant lack of consistency in the sense that there is no mechanism, which ensures that the market prices p_t and production volumes q_{it} calculated as output from the power market model will be identical to the values used as input in the risk adjustment module. In fact one obtains a framework where an initial exogenous input value for a given parameter will affect the output value of that same parameter.

The level 1 approach can be made more consistent through an iterative procedure where output from the power model is used as input to a subsequent run with the risk module. By repeating this type of iterative procedure until convergence, the mean values for prices and production volumes can then be made consistent in the two modules. However, because market prices and production volumes are functions of the specific technology costs and the structure of demand, it is crucial that dependencies between all of these four parameters are modelled in the risk adjustment module. The need to specify such dependencies exogenously is generally a more difficult task and hence a significant drawback with this level 2 approach.

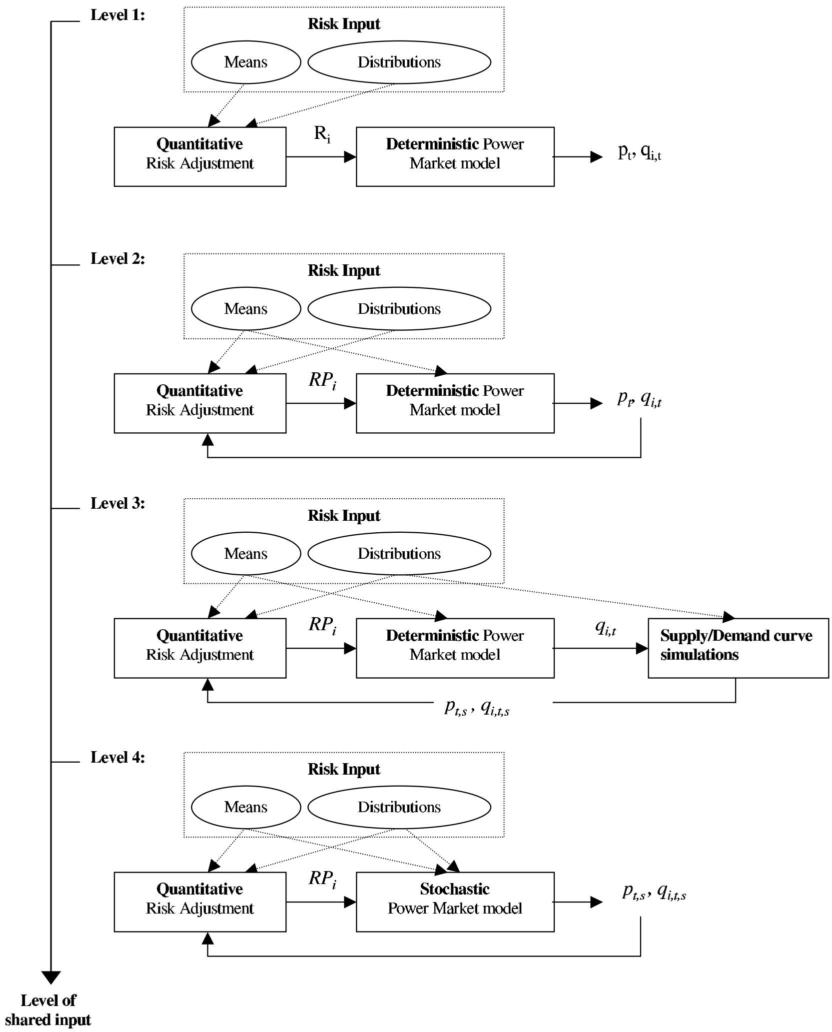

Figure 3.4: Different levels of consistency in a framework for risk inclusion based on a separate PE model and risk module.

Level 3 improves consistency by using data from the risk module on cost, demand and volume distributions to calculate the distribution of prices and production quantities. It does so however without resorting to the complex construction of a stochastic model. The basic idea is to use the optimal capacity mix obtained as output from the deterministic power market model as the basis for scenario simulations. This additional Monte Carlo simulation module uses the exogenous data concerning distributions of cost and demand (and any production volume effects not controlled by the decision maker) to simulate scenarios s for hourly supply and demand curves in a system based on the capacity mix found by the power market model. This leads to a distribution of prices $p_{t,s}$ and production volumes $q_{t,i,s}$ and hence eliminate the need for exogenous assumptions about the distribution of these parameters and correlations. The section on experimental results in Paper D examines the use of a level 3 approach in detail.

Level 4 further enhance consistency by making the optimization model stochastic. The risk module and the PE model can still by kept separated in order to keep the structure of the stochastic optimization model as simple as possible, however an iterative procedure will then still be required to secure consistency between risk premiums, production volumes and market prices. Level 4 comes closest to the analytical framework suggested in Hazell & Norton (1986) since the optimization will take the stochastic nature of demand and supply curves into account. It is more consistent than level 3 but also considerably more difficult to solve.

3.3 The regulator's perspective

The California debacle (Faruqui (2001)) showed that liberalization of electricity markets will neither decrease the need for regulation nor make it less complex. To become a successful experiment the market must be designed to provide a satisfactory balance between the three main requirements of economic efficiency, security of supply and environmental protection (ECON (2002)).

The first fundamental welfare theorem establishes a benchmark for social optimality and states that regulatory market intervention should be motivated when market imperfections or sources of market failure lead to incomplete or imperfectly competitive markets. Market imperfections include transaction costs, whereas sources of market failure include the four main categories; externalities, public goods, informational asymmetries and market power (Pindyck & Rubinfeld (1998)).

A primary task for regulators is to access whether or not the characteristics of electricity as a good will lead to such market imperfection or sources of market failure and to design the market to minimize the potential consequences of these factors.

3.3.1 Demand side flaws and the quality dimension of electricity

To understand the link between sources of market failure and security of supply it is useful to view electricity in terms of both a quality and a quantity dimension. Electricity is not valued solely as an end-product by consumers, but rather through the services that it provides. Most electricity dependent services are planned ahead and are based on the assumption that a stable supply of electricity will be available at request. Electricity is therefore not only valued through its quantity dimension, but also in terms of reliability as a quality dimension.

The qualitative dimension of electricity has public good characteristics. Once a unit of capacity has been added to the system all consumers benefit from the increased reliability that it provides (Abbott (2001)) and electricity quality is therefore a non-exclusive good. Reliability is also a non-rival good, because once produced it is unaffected by the amount of consumers that obtains a benefit.

The non-exclusive property of reliability arises because system operators lack the technology required to disconnect consumers individually in case of an inadequate supply. This lack of technology is characterized by Stoft (2002) as the second demand side flaw of electricity markets[9]. A similar point was actually stressed in much earlier work on public utility pricing (Brown & Johnson (1969)).

[9] The first demand flaw is a lack of real-time metering and real-time billing, which causes a lack of demand elasticity in the market.

3.3.2 System security and system adequacy

Electricity is not delivered at discrete points in time, but rather as a continuous flow of electrons. Even though consumers can gradually change their consumption patterns and make decisions based on real-time metering they cannot continuously monitor prices and react on a continuous basis. The electricity market is therefore generally structured through a series of forward markets where production and consumption plans are balanced. An real-time price adjustment is then performed ex post, once deviations between traded volumes and the actual real-time exchange becomes known. Handling of real-time deviations between the planned balance and the actual balance requires detailed information about supply, demand and transmission conditions throughout the interconnected system. By economies of coordination it is generally most efficiently handled by a centralized unit such as an independent system operator.

Reliability of electricity systems is usually described through the two components of system adequacy and system security. System security refers to the system's ability to withstand sudden short-term disturbances such as an unexpected loss of system elements. System adequacy implies that a sufficient amount of generation capacity is installed to ensure system security in the long term[10] (Morey (2001)). Although this terminology is common in the literature, it is important to realize that the two concepts are highly interdependent. System adequacy is by definition a prerequisite for system security, because long-term decisions inevitably affects system balancing in the short-term. Similarly, one can view the long-term as made up by a series of short-terms. System balancing in the long-term is therefore only relevant for system reliability to the extent that it helps ensure system balancing in the short-term.

Another way of looking at the responsibility for system balance is to distinguish between a physical and a financial responsibility. System operators are generally held responsible for maintaining a physical balance through operation of the real-time market, whereas market players (e.g. producers, retailers and consumers) are held financially responsible for balancing of traded volumes ahead of real-time.

[10] A more stringent technical definition of the two terms can be found in Stoft (2002).

3.3.3 Commercial capacity and ancillary services

Electricity supply and demand must be kept in a near instantaneous balance to avoid fluctuations in frequency and voltage that can damage transmission and generation equipment. The requirement of a near instantaneous balancing between supply and demand in electricity markets, imply a need for production capacity with different operating characteristics. A fundamental distinction is generally made between commercial capacity operating reserves. Operating reserves are part of a long list of ancillary services used by the system operator to ensure physical balancing and reliability in the system. This section address only operating reserves used to provide frequency control. What separates operating reserves from commercial capacity is that they contribute directly to the quality dimension of electricity by fulfilling requirements to response times and activation method set by the system operator.

Frequency control services close the gap between the last ex ante trade and real-time, by balancing any deviations. In the dimensioning process they are typically divided into contingency reserves and regulation reserves (NEMMCO (2001)). Contingency reserves are used to replace capacity lost as a result of a forced outage in either generation or transmission elements. Regulation reserves are used to correct for imbalances due to forecast errors in production or consumption. Activation times differ depending on the way such capacity is used by the system operator (e.g. as primary, secondary or tertiary contingency reserves).

The key problem with a market based solution for operating reserves lies with the demand side of the market. The economics of coordination and the lack of speed in bilateral markets, imply that a market for operating reserves must be run at some point before real-time. In a perfectly competitive and complete market each balance responsible participant[11] should be willing to demand reserve capacity until a point where the ex ante market price equals the expected ex post costs of the expected level of real-time imbalances.

However, any increase in the amount of capacity reserves supplied to

[11] We use the term balance responsible participant to define market players who are held financially responsible for any real-time imbalances compared to traded volumes in the energy market.

the market through the reserve market will increase the reliability for all consumers and decrease the general costs of imbalances. The full value of reliability will hence never be captured by the entity paying for the operating reserve capacity in the reserve market. This is the free rider problem associated with the public good property and indicates that supply and demand in such a market will not accurately reflect the consumers preferences for reliability. The system operator must therefore estimate and procure operating reserve capacity in the reserve market on behalf of consumers or more generally on behalf of balance responsible entities.

3.3.4 Models for regulation of system balance

The following assumes a system where the system operator is held responsible for physical balancing of the system and where and market players are held financial responsible for balancing their trades in the energy market[12]. The element of capacity regulation in the market design can then distinguished by: A) The degree and method of regulation used by the system operator to ensure the capacity required for physical real-time balancing of the system, and B) The method used to enforce the financial responsibility of market participants.

Focussing on the distinction between commercial capacity and operating reserves we list three main categories of market models:

1. Value of Lost Load (VOLL) pricing
2. Regulation of Operating Reserves (OR)
3. Regulation of Commercial capacity and Operating Reserves

Value of Lost Load pricing: The first demand side flaw of electricity

[12]We use the term energy market to describe the last forward market where the smallest traded time blocks are priced *ex ante*. The term physical market is misleading because the actual physical trading can only take place in real-time with *ex post* pricing. We therefore use the term energy market to describe the last forward market before the actual real-time measurement e.g. a day-ahead, an hour ahead or a half-hour ahead market.

markets implies that the lack of real-time metering and transaction costs associated with continuous trading can lead to situations where available supply cannot cover the inelastic part of the real-time demand curve. During periods with load shedding market prices must be capped at some finite level. This price cap P_{cap} will be regulatory and will effectively cap the prices in all forward markets. The cap express the price that the system operator would be willing to pay for an additional unit of capacity value and should optimally approximate the Value of Lost Load (VOLL) i.e. the cost incurred by consumers who are involuntarily disconnected.

The key element of a pure VOLL pricing model is that no regulatory action takes place until the point where load shedding is necessary. The public good aspect of electricity quality implies however, that the system operator must impose an artificial demand in the reserve market and a system based purely on VOLL pricing is therefore primarily a theoretical model.

Regulation of Operating Reserves: Two main streams of models for regulation of operating reserves can be identified by distinguishing between whether or not the auction for capacity reserves (the reserve market) is cleared before or after the energy market is cleared[13].

Reserve market cleared *after* the energy market: Models where the system operator purchases a predetermined level of operating reserve capacity OR in the reserve market after the energy market has been cleared, will be termed OR_{expost} models. Such models are based on the operating reserve requirement OR and the price cap imposed when the requirement cannot be met P_{cap} as the two key regulatory parameters. This type of model is described in detail in Söder (2002) and Stoft (2002).

Söder (2002) describes the model in terms of a single market where energy prices are capped whenever the available amount of total capacity falls below OR . The price cap P_{cap} limits the size of price spikes in the market and the operating reserves requirement determines the duration of such price spikes. The Loss Of Load Probability (LOLP) will in the long-run be determined completely by the regulatory parameters P_{cap} and OR

[13] The market could be designed with a simultaneous clearing of the two markets, however the distinction still holds in such a context, since one of the markets must take precedence in the clearing process.

and the shape of the demand distribution. Under stylized assumptions (such as risk neutrality) system operators can obtain the desired level of LOLP (in long-run equilibrium) through an infinite combinations of P_{cap} and OR. A small P_{cap} requires a correspondingly large OR and vice versa.

Stoft (2003*a*) shows that the single market analogy can be extended to systems where the market is divided into an energy market and a market for operating reserves. The price cap is then the maximum price paid for reserves during periods where available reserve capacity is less than the required amount OR.

The equivalence with the Söder (2002) framework rests on the assumption of arbitrage between the two markets. Most producers that can supply operating reserves could alternative choose to supply this capacity in the energy market. This implies that there will be an arbitrage relation between the energy market price and the reserve market price[14] adjusted for risk i.e. $P_{energy} = E[P_{reserves}]$+RP[15]. If players anticipate a shortage of supply in the reserve market they will refrain from selling production in the energy market until the expected payment for reserves[16] defined by the price cap equals the energy market price. The price cap imposed in the operating reserve market will therefore translate into a price cap on energy market prices, which in turn will drive the incentive for investments in both commercial capacity and reserves.

Stoft (2002) states that the use of a large OR requirement and a correspondingly small P_{cap} can be desirable, because this combination increases the duration of price spikes and decrease the size. This has the positive effect of decreasing financial risk and the potential for exercise market power. The tradeoff is that production capacity with marginal costs above P_{cap} or demand flexibility with a marginal willingness to pay above P_{cap} are lost to the market. The pure VOLL model described in (Stoft (2002)) can be seen as a special case of this framework with $OR = 0$ and $P_{cap} = VOLL$.

[14]Reserve market price is seen here as the total payment for reserves, which may include both a capacity and a real-time energy price component.

[15]The risk premium RP expresses the cost of hedging risk associated with the supply of reserve power

[16]Again properly adjusted for any costs of hedging in the reserve market.

A key problem with the stylized OR_{expost} models, described in Söder (2002) and Stoft (2003a), is that the models are based on the assumptions that new capacity can be added instantaneously and that LOLP can be interpreted as a long-run equilibrium value. Both assumptions have the unfortunate effect that the model ignores the aspect of short-term reliability. The system operator does not ensure that the amount of required reserve capacity is actually available in the reserve market at all times i.e. in the short-term. Periods with an insufficient amount of operating reserve are actually an integrated part of the model, because they provide the key incentive for new investments.

Reserve market cleared *before* the energy market: The OR_{exante} model reverses the order by which the energy and reserve market are cleared. By clearing the reserve market ahead of the energy market the system operator ensures that the capacity needed cover the estimated demand for operating reserves is available when needed.

Keeping capacity for operating reserves out of the energy market does not increase total system capacity and the short-run effect is therefore a correspondingly decrease in the capacity made available in the energy market. The OR_{exante} model does however represent a potential improvement in short-run reliability, if consumer price flexibility is more correctly displayed in the energy market than in the real-time market. A consumer price flexibility that enables clearing of the energy market at a finite price at all times, is a sufficient condition for such an improvement.

The need for price caps in the reserve market arise with a probability corresponding to the estimated short-term LOLP. Though the price cap imposed during such periods should reflect estimated VOLL, this regulated price is not a crucial parameter for investments in new capacity in the OR_{exante} model. Periods with insufficient reserve capacity in a OR_{exante} occur with a short-run LOLP probability determined by the system operator, rather than as a result of investments made based on the P_{cap} prices as in the OR_{expost} model.

Producers (or consumers) who sign a contract with the system operator for the supply of operating reserves, are effectively selling a call option on the right to supply that capacity in the energy market. Such an option has a value that depends on the time horizon for contracting and on the way that pricing in the real-time market is structured. Paper C analyzes the call option based model for regulation of operating reserves and the resulting interaction between energy and real-time prices. The analyzes illustrate a series of complex effects, which must be considered in the design of markets based this type of regulation.

Comparison and literature: The main potential drawback with the OR_{exante} model is the economic costs of ex ante regulation. The uncertainty related to real-time imbalances are an increasing function of the time horizon $\Delta T(RM \rightarrow RTM)$ and long-term contracting will therefore tend to more conservative and hence more costly. If the energy market clears at a finite price at all times, then the OR_{exante} model should ensure a short-run LOLP regardless of the time horizon used and short-term contracting will then be preferable.

Supply and demand are random variables and the risk of load shedding due to situations with insufficient operating reserves can never be eliminated. Even the OR_{exante} model must impose price cap regulation during such occurrences. The key difference between the two models is however, that the OR_{exante} model provides a capacity payment in advance to avoid such situations. In the OR_{expost} such payments are only provided once a shortage of operating reserves actually occurs.

The complex structure of OR models has been extensively treated in recent literature. Nilssen & Walther (2001) describe the construction of a Norwegian market for call options on capacity for handling imbalances between volumes traded day-ahead and actual real-time balances. Amundsen & Mortensen (2001) and Lauen, Bjorndahlen, Hauch & Engberg (2003) provides a general analysis of different models for regulation of operating reserves within the Nordic market model. Söder (1999) discusses the aspect of responsibility in this type of model structure and Chao & Wilson (1999) and Stoft (2002) describe an auction model for optimal design for call options on reserve capacity. Finally, paper C presents an overview of models and an analysis of the different design parameters in a call option based system.

3.3.5 Regulation of commercial capacity

The Installed Capacity Payments (ICaP) model currently implemented in several US market designs (Bowring & Gramlich (2000)), (NYISO (2003)) and (CAISO (2002)), is the most widely applied and studied model that includes capacity regulation of commercial reserves.

The ICaP approach sets up an explicit market for capacity over a given time frame. Demand is driven by imposing a regulatory obligation on load-serving entities to buy capacity credits corresponding to their expected demand during the time period. Hoobs, Inon & Kahal (2001) describes the ICaP as a model based on:

- A definition of the total amount of installed capacity (Q_{ICap}) required, based on expected demand and reliability requirements;
- An allocation of responsibility for this capacity and establishment of a system for trade of capacity credits;
- A penalty for non-compliance $P_{penalty}$

The time horizon $\Delta T(ICap \rightarrow RTM)$ used for enforcement of the capacity requirements should be added to these characteristics as an important additional parameter. If this time horizon is less than the lead times of investments in new capacity the ICap model will have a pricing mechanism analogous to the OR_{expost} model.

Since the capacity mix is fixed during the ICap period[17] a competitive ICap market price can only be in one of two possible states. Either the required level of capacity is not available during the period, and the capacity price will then be equal to $P_{penalty}$ signalling a need for more investments. This corresponds to the situation in the OR_{expost} model where available reserve capacity is less than OR and the price is capped at P_{cap}. If alternatively, the available amount of capacity is larger than the Q_{ICap} requirement a competitive market will lead to a capacity price of zero. Following the analogy to the OR_{expost} model this corresponds to

[17] Due to the assumption of time horizon shorter than lead times of new capacity

periods where sufficient capacity bids are available and the reserve price equals the reservation costs of the marginal unit.

The key thing to notice is that capacity credits will have a positive price and hence provide scarcity rent only during those periods where capacity is insufficient and ICap prices equal $P_{penalty}$. Although suggested in numerous papers, the idea that the ICap market price would equal the amortized fixed cost component of new capacity in a competitive market, is fundamentally flawed. The only thing that should keep a rational generator from selling ICap certificates at a price infinitely close to zero, when the available supply exceeds regulated demand, would be the opportunity to exercise market power or the opportunity to bank certificates for sale during subsequent ICap periods. Similarly, consumers would always pay a price infinitely close to the penalty price for certificates in periods where demand exceeds available supply, unless the ICaP period is made long enough to enable new investments within the period.

The ICap price mechanism is similar to the long-term framework analyzed in paper E on markets for Tradable Green Certificates. In this system the ability to bank certificates between the time periods is a vital part of the pricing mechanism and is essential for the argument that prices will settle at the sum of amortized fixed costs and variable costs (i.e. the long-run marginal costs) for new investments. If the concept of banking was transferred to the ICap model it could potentially improve the pricing mechanism, however the consequences for supply security within each period would have to be analyzed and this idea has not been treated in any literature describing the ICap system.

Capacity auctions or tendering rounds for investments in new commercial capacity can as a parallel to the OR_{exante} model for operating reserves. In such an approach the system operator would plan in advance how much capacity is needed in the system and pay for it through auctions held sufficiently ahead of real-time to account for the lead times associated with plant construction. Regulation of commercial capacity with such approach implies that the system operator takes over the completely responsible for new investments. This would contradict one of the main arguments for liberalization, namely that financial incentives in a market would improve such decision making.

An analysis of methods for regulation of both operating reserves and commercial capacity is provided in paper C where a general framework for capacity regulation models is provided.

3.4 Concluding remarks

This chapter has reviewed problems related to investments in generation capacity and security of supply from three different perspectives. References to relevant literature has been provided and the chapter has indicated how the papers C, D have contributed to research in this area.

Chapter 4

Conclusions

The preceding chapters have analyzed specific problems related to risk management and investment decisions in liberalized electricity markets. Theory and applications have been reviewed and the five papers have contributed to research within specific problem areas.

The five papers have covered a broad area, but are bound together by a focus on the effects of financial risk in a liberalized electricity market. All five papers have contributed to the primary goal of the thesis, to increase the understanding of how the introduction of competitive markets affects the financial risk related to risk management and investment related decision problems in electricity markets. Particulary paper C and D and E have have focussed on applied microeconomics and the analyzes of the interplay between market design and the technical characteristics of the electricity system. Papers A, B and D have contributed directly to the secondary goal of development of modelling tools, that enable decision makers in liberalized electricity market to take financial risk into account.

Paper A has provided a modelling tool for construction of high resolution forward price curves and illustrated the value of a combined use of bottom-up data and market price data. Experimental results showed that the model outperforms best alternative models based solely on market data.

Paper B has analyzed financial models for electricity price modelling and illustrated that the set of market based input data used for such modelling are likely to have a larger effect on subsequent decision problems than structural choices.

Paper C has shown how different models for capacity regulation are linked and has analyzed sources of market failure and market imperfections induced by electricity market characteristics. Two distinctions are shown to be critical for capacity regulation A) whether regulation is restricted to operating reserves only or includes both commercial capacity and operating reserves and B) the method of procurement and particularly whether or not operating reserve capacity is reserved and hence kept out of the energy market.

Paper D has presented a framework for inclusion of investment risk into partial equilibrium models based on a tradeoff between consistency and model tractability. The framework shows how the practically accepted risk measure Value at Risk can be implemented in such market models and illustrates that the inclusion of stochastic demand and stochastic variable cost affects the optimal capacity mix and hence market prices differently.

Paper E has derived mean-variance risk management strategies for wind turbine owners in a market system with tradable green certificates. The negative correlations between electricity prices and TGC prices and between volume and price in the TGC market are illustrated and used to examine the consequences of such market design.

The relatively broad areas covered by the papers in the thesis has indicated a need for further research along several dimensions. Risk management measures need to be developed to more accurately fit the characteristics of electricity markets and electricity assets. The general lack of data for individual risk factor modelling and modelling of dependencies between risk factors should also be addressed and more advanced methods for data selection must be developed.

Concerning investments there is a need for an improved modelling of the effect of financial risk on investment decisions both at an individual and a market level. Modern investment theory has focussed on real option values and this perspective has also received significant attention in electricity applications. The modelling of how risk affects the investment decision, has however received relatively scarce attention in electricity market applications. The topic has been addressed at a market level and from a modelling point of view in this thesis.

Finally, there is a need for further research on the effects of different types of capacity regulation in a liberalized market setting. This thesis has addressed the topic by providing an overview of models and a qualitative analysis, however theoretical work and quantitative analysis of more complex market design structures are needed.

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