Linköping Studies in Science and Technology, Dissertations
No. 470

Cooperation in local electricity markets

Modelling of Technical Measures

Maria Andersson

Division of Energy Systems
Department of Mechanical Engineering
Linköping University, S-581 83 Linköping, Sweden

Linköping 1997

Linköping Studies in Science and Technology, Dissertations
No. 470

Cooperation in local electricity markets

Modelling of Technical Measures

Maria Andersson

Division of Energy Systems
Department of Mechanical Engineering
Linköping University, S-581 83 Linköping, Sweden

Linköping 1997

Abstract

This thesis presents a system analysis for cooperation in local electricity markets including distributors and customers. The purpose of cooperation is to minimise the system cost of local markets by introducing system measures, such as end-use measures and municipal cogeneration plants.

Cooperation will strengthen the position of local markets in the national as well as future international electricity markets. With end-use measures local markets will achieve flexibility, additional reserve capacity and ability to avoid sudden large costs for peak loads. Biomass-fired cogeneration plants can become of great importance in an international market. In Sweden there is a simultaneous demand for electricity and district heating, many local markets already include district heating systems and there are major forest areas which can contribute with renewable fuel.

The system analysis is partly based on the simulation model (*INDSIM*) and the linear programming model (*MODEST*). The simulation model has been further developed (*STRATO*) to include calculation of system costs. Shadow price analysis has been developed in order to study incentives for system measures. Calculation procedures have been developed that describe cooperation between distributor and customer.

Six case studies of a selection of real, existing local markets in Sweden are presented. The studies show the potential economical effects of cooperation measured by system costs and shadow prices. Cooperation has been considered between demand- and supply-side, electricity- and district heating systems and also between different time periods. In a typical local market with 90 000 inhabitants, if end use measures are introduced without cooperation the system cost of the distributor will increase by 14 million SEK for a time period of 25 years. If instead end-use measures are introduced in cooperation, together with a biomass-fired cogeneration plant, the system cost of the local market will be reduced by 444 million SEK. Furthermore, the use of biomass in the local market is increased from 36 to 72 % while the use of oil is decreased from 34 to 1%. Another case study of another local market (50 000 inhabitants) shows that end-use measures will reduce the system cost (excluding investment costs) of an industry by 50 % corresponding to 1.3 million SEK for one year. The end-use measures imply reduced power demand during peak load periods in the local market and increased power demand during non-peak load periods.

II

In this thesis there is an introduction, a literature survey of related work and a description of the Swedish electricity market. These chapters are followed by a description of the method for system analysis, a case study (which is a continuation of *Paper V*), concluding remarks and comments on enclosed papers.

The following papers are included and will describe case studies where the system analysis method has been applied.

- (I) Andersson, M., Björk, C. and Karlsson, B., Cost-effective energy system measures studied by dynamic modelling, *Proceedings of the international conference on Advances in Power System, Control, Operation & Management* (invited paper), Institution of Electrical Engineers (IEE) December 7-10, Hong Kong, pp. 448-455, 1993.
- (II) Andersson, M., Björk, C. and Karlsson, B., Energy system cost reduction as a result of end-use measures and the introduction of a biomass-fired cogeneration plant, *Proceedings of the international conference on Renewable Energy - Clean Power 2001*, Institution of Electrical Engineers (IEE), November 17-19, London, pp. 37-42, 1993.
- (III) Andersson, M., Shadow prices for heat generation in time-dependent and dynamic energy systems, *Energy - The International Journal*, Vol. 19, No. 12, pp. 1205-1211, 1994.
- (IV) Andersson, M. and Karlsson, B., Cost-effective incentives for cooperation between participants in the electricity market, *Applied Energy*, Vol. 54, No. 4, pp. 301-313, 1996.
- (V) Andersson, M. and Karlsson, B., Cost-effective incentives for end-use measures in a Swedish municipality, *Proceedings of the international conference on ECOS' 96, Efficiency, Costs, Optimization, Simulation and Environmental Aspects of Energy Systems* (Edited by Per Alvfors, Lars Eidenstam, Gunnar Svedberg & Jinyue Yan), Royal Institute of Technology, June 25-27, Stockholm, pp. 557-564, 1996.

III

Papers not included in this thesis but referred to in the text.

- (i) Andersson, M., Björk, C. and Karlsson, B., A model for industrial load management optimisation and its application on an industry and a municipality, *Proceedings of the Canadian Electrical Association's Demand-Side Management Conference*, October 22-24, Toronto, Canada, pp. 161-171, 1990.
- (ii) Andersson, M., Backlund, L., Björk, C. and Karlsson, B., Short range marginal costs in the Swedish electric energy system, *Proceedings of the international conference on Metering Apparatus and Tariffs for Electricity Supply*, Institution of Electrical Engineers (IEE), November 17-19, Glasgow, UK, pp. 5-8, 1992.

Acknowledgement

During the work on this thesis I have had the opportunity to work with many inspiring persons. I wish to thank my supervisor Prof. Björn Karlsson for valuable guidance, encouragement and support during the course of this work.

I would like to express my gratitude to Tekn. Dr. Curt Björk, Tekn. Dr. Lennart Backlund and Tekn. lic. Dag Henning for valuable advise concerning energy system models. I also want to thank all other present and former colleagues in the Energy System group for companionship and fruitful collaborations, and especially Tekn. Dr. Stig-Inge Gustafsson and Tekn. Dr. Mats Söderström for sharing their long experience in energy system research.

Furthermore I want to thank the following persons for sharing their knowledge about specific distributor and customer systems and experience from the energy market: Calle Lindroth (Borlänge Energi AB), Magnus Lundberg (Gävle Energi AB), Matts Wesslén (Vattenfall AB), Bengt Kvist (Vattenfall AB) and Lars Andersson (Eskilstuna Energi & Miljö AB).

Financial support from SEU (Svensk energiutveckling AB), NUTEK (the Swedish national board for industrial and technical development), Borlänge Energi AB and Vattenfall AB is gratefully acknowledged. I also wish to express my gratitude to Bo Rydins' Foundation for Scientific Research for a travel grant to a conference in Hong Kong 1993.

Finally, I wish to thank my husband Roland for encouragement, participation and for being my greatest supporter during these years, and also Marcus, our beloved son, for giving me inspiration and many joyful moments.

Linköping in March 1997

Maria Andersson

Table of contents

1	INTRODUCTION	1
1.1	Background	1
1.2	Hypothesis	4
1.3	Procedure	4
2	LITERATURE	9
2.1	Introduction	9
2.2	The future electricity market	9
2.3	Demand elasticities and welfare maximisation	13
2.4	Energy system models and analyses	16
2.5	Concluding remark	27
3	THE SWEDISH ELECTRICITY MARKET	28
3.1	The supply- and demand-side	28
3.2	The deregulated market	32
3.3	Pricing of electricity	34
3.4	Taxes and charges	35
4	SYSTEM MODELS FOR DISTRIBUTOR AND CUSTOMER	37
4.1	<i>MODEST</i>	37
4.2	Shadow prices	42
4.3	<i>STRATO</i>	43
5	ANALYSIS AND CALCULATION PROCEDURES	49
5.1	Lack of cooperation	49
5.2	Cooperation	51
	5.2.1 Cost reduction - <i>MODEST</i>	53
	5.2.2 Cooperation - power cost	54
	5.2.3 Cost reduction - shadow price	54
	5.2.4 Cost reduction - load priority system	55
6	END-USE MEASURES AND ENERGY AND GRID TARIFFS	58
7	CONCLUDING REMARKS AND FUTURE OUTLOOK	63
8	COMMENTS ON ENCLOSED PAPERS	68
9	LIST OF SYMBOLS	71
10	REFERENCES	74
	PAPERS I - V	81

1 Introduction

1.1 Background

The electricity system is an important infrastructure in the society. Electricity is used by, among others, industries, households, communication and commerce. It is generated using nature resources such as fossil fuels, uranium, water, biomass and wind. The price of electricity is important for how much electricity will be used, for instance in comparison with fuels in heating. The price of electricity can also be used to promote a more cost-effective use of the electricity.

The price of electricity for Swedish electricity customers is, and will be, influenced by changes affecting the electricity market conditions in Sweden and in neighbouring countries. Such changes are deregulation of electricity markets, new environmental taxes and charges, increased electricity trade between countries and investments in new power generation plants.

At the turn of the year 1995/1996 the Swedish electricity market was deregulated and actors such as power producers, distributors and customers faced a new situation where electricity sellers must compete for the buyers. In a short time perspective the deregulation will most probably mean lower electricity prices as a result of the increased competition. In a longer time perspective there are factors that point towards increased electricity prices, despite the deregulation. Such factors are the need for new power generation plants, in Sweden or in the world around, and increased trade between Sweden and countries characterised by high electricity prices.

An interesting system solution in a variable electricity market is the cooperation between actors aiming at obtaining lower costs for the common energy system. Cooperation is established when electricity buyers form groups in order to found one large buyer, or actor. A large actor has a greater possibility to choose between sellers and to make a more favourable electricity agreement. Cooperation is also established when distributor and customer introduce *measures* which aim at reducing costs for the local market including distributor and customers. Measures can include end-use measures and large-scale cogeneration plants. End-use measures are e. g. load management, efficiency improvement in energy use, energy conversion and local electricity generation. It is this second type of cooperation which will be discussed in this thesis.

The variation in electricity demand during the day differs between distributor and customers. Peak loads of the individual subsystems and the total system will, in most cases, not coincide in time. When end-use measures are introduced it is important to consider the differences in electricity demand in order to avoid suboptimisations within the local market.

Generally, end-use measures can be divided into, at least, three different types according to the way they will influence the electric load profile. End-use measures can reduce peak loads, i. e. energy demand during very short time periods. Such measures are for instance load management and local electricity generation in reserve power plants. End-use measures can also reduce demand in a longer time perspective. Such measures are efficiency improvement, energy conversion from electricity to fuel and electricity generation in small-scale cogeneration plants. Besides, end-use measures can imply an increase in electricity demand. This will occur if electricity replaces fuel in heating processes.

If a distributor has access to a municipal district-heating system the introduction of a cogeneration plant can reduce the system cost. Municipal cogeneration plants are profitable in local markets due to the simultaneous demand for electricity and district heating, especially during winter months. A large cost reduction will be obtained, among other things, as a result of reduced electricity purchase from the power producer.

In this thesis it is the system cost for a certain time period which will indicate what type of measure that is the most profitable one. The system cost includes e. g. electricity costs, fuel costs, maintenance costs for system components and investment costs for system measures. The purpose of a system analysis is to minimise the system cost with given boundary conditions and by that utilise scarce resources in a more cost-effective way.

The thesis is a continuation of the licentiate thesis '*Cost-effective incentives for local electric utilities and industries in cooperation - modelling of technical measures*' (Andersson, 1993). The licentiate thesis deals with the economical consequences of cooperation and lack of cooperation, when end-use measures and municipal cogeneration plants are introduced in the local market. This thesis will present a further development of the analysis procedure for cooperation and more case-studies.

The case-studies will treat the introduction of end-use measures and municipal cogeneration plants and also the variation in marginal costs for electricity and district-heating demand. The calculations are based on measured power data of customers' energy use and distributors' electricity purchase from power producers. In addition, knowledge has also been obtained by means of

close collaboration with, first of all, representatives from electricity customers and local distribution companies, but also with representatives from power producing companies.

System boundaries. The result of a system analysis will depend highly on the definition of the system and, with that, what boundary conditions that will exist.

If the system is defined by the customer, prices and charges for electricity purchase from the distributor to the customer will form boundary conditions. The system cost represents the costs of the customer. The prices and charges will indicate what type of end-use measures that will be profitable for the specific customer. If the system is defined by the local market, the prices and charges for electricity purchase from the power producer to that system will form boundary conditions. The system cost represents the costs of the local market. In this case the prices and charges will indicate what measures that will be profitable for the customer *and* the distributor. If the system is defined only by the distributor, when the profitability for cogeneration plants is analysed, there is no consideration taken to possible end-use measures. When the system also includes the customers, a simultaneous introduction of end-use measures and a cogeneration plant can reduce the size of the plant. These system definitions have been applied in the case-studies presented in this thesis.

If the system should also include the power producer, the costs for electricity generation will be important for system cost and measures in the local market. If there is a very small probability for energy or power shortage in the national system, the profitability for measures in local markets will be relatively low. If the probability for energy or power shortage is high, the profitability for measures will increase.

If the electricity trade with neighbouring countries should increase, the electricity generation costs in the other countries will affect the profitability for measures in Sweden. The system can here be defined by the Nordic countries, the Baltic states and the northern part of the European Continent. If the trade with Germany should increase, electricity export from Sweden will most certainly increase, especially during daytime, since generation costs are higher in Germany than in Sweden. A higher demand in Sweden will presumably increase the Swedish electricity prices and hence the profitability for measures in local markets.

Other important boundary conditions are taxes and environmental charges. The difference in taxation between industrial and non-industrial customers plays an important role for end-use measures that include both electricity and fuel use (bivalent heating and energy conversion). Taxes and

environmental charges are also important for the district-heating system when, for instance, analysing introduction of various cogeneration plants.

1.2 Hypothesis

Cost-effective incentives for introducing measures will arise if the distributor and customers cooperate. Cooperation is necessary since the separate customer systems and the common distributor system are characterised by different load profiles.

It is possible that by using analysis tools such as simulation and optimisation models create a method for analysing the profitability for cooperation and measures in local markets.

Cooperation is considered in the simulations and optimisations by regarding the distributor and customers as one system, or actor, in the electricity market. Lack of cooperation is considered by regarding the distributor and customers as separate systems.

Cost-effective measures are identified by looking at the system cost of the specific system and also marginal costs for power and energy demand in different strategic time periods of the year.

1.3 Procedure

To analyse the profitability for measures an analysis procedure has been developed. The procedure comprises simulations and optimisations of energy use in customer and distributor systems. The procedure also comprises interpretation of shadow prices associated with the optimisation results. The simulation model *STRATO* (Andersson, 1993), which is based on *INDSIM* (Björk, 1989), simulates the energy use of individual systems for different types of end-use measures. The measure of profitability is given by the system cost. The simulation procedure has been further developed to improve the representation of cooperation between distributor and customer.

The optimisations have been carried out with the linear programming model *MODEST* (Backlund, 1988), (Henning, 1994). *MODEST* is used to calculate the cheapest way of meeting electricity and district-heating demand in municipal systems. Measures can include cogeneration plants and end-use

measures. As for *STRATO* the measure of profitability is given by the system cost. Since *MODEST* is based on linear programming, shadow prices can be derived showing marginal costs for electricity and district-heating demand. Interpretations of shadow prices have been carried out and will be presented in this dissertation.

The aim of the analysis procedure is to identify measures in the local market which will minimise the system cost and in that way increase the cost-efficiency of the system. With the procedure it is also possible to show the consequences of lack of cooperation.

The case-studies are presented in five papers and in *Chapter 6*. Below there is a short description of the contents in the papers and in *Chapter 6*. There are also short descriptions of related work.

Paper I illustrates the economical consequence of regarding the distributor and customers in a local market as separate systems when end-use measures and a cogeneration plant are introduced. The paper also describes the economical consequences of cooperation, i. e. when the distributor and customers are regarded as one system. The local market represents a municipal system (90 000 inhabitants) situated about 100 km west of Stockholm. Thirty customers participated in the project and most of them are industries.

The results show that if end-use measures are introduced without cooperation the customers will reduce their system costs by 26 million SEK over a time period of 25 years, while the distributor will increase its system cost by 14 million SEK. Consequently, the total system cost reduction of the local market is 12 million SEK. The maximal power reduction capacity from the end-use measures is 3.3 MW while the peak load reduction in the local market is only 1.1 MW. This is due to the fact that peak loads in different subsystems appear at different points of time. If distributor and customers cooperate when end-use measures are introduced the common system cost is reduced by 93 million SEK. The maximal power reduction capacity is now increased to 17 MW. Furthermore, if a cogeneration plant based on biomass is introduced the system cost reduction is increased to 444 million SEK (including investment subsidy). The optimal size of the plant for that case is 38 MW electricity and 84 MW useful heat. If there is no consideration taken to end-use measures the size of the cogeneration plant is somewhat larger. Part of the study has been presented by Andersson et al (1990, 1991). A more detailed description of the analysis is presented in the licentiate thesis (Andersson, 1993).¹

¹ For further reading concerning related analyses see Björk (1991) and Dag and Björk (1996).

Paper II focuses on the consequences of introducing the biomass-fired cogeneration plant that is suggested in *Paper I*. With a cogeneration plant cooperation between the electricity and district-heating systems will be enabled. As a result of the new cogeneration plant there will be a drastic change in fuel mix in the district-heating system.

The results show that the use of biomass is increased from 36 to 72 % (288 to 576 GWh for one year) and the use of oil is reduced from 34 to 1 % (272 to 8 GWh for one year). In the optimised system oil is used only during peak load hours.

In *Paper III* shadow prices for municipal district-heating have been analysed. The district-heating system, which is the same as in *Papers I* and *II*, uses electricity, gas, biomass and oil for heat generation. It is particularly the influence of energy storage on the shadow price and system cost that is discussed. When storage is introduced the system will be dynamic, and the situation in one time period will also depend on system conditions in other time periods. The dynamic system makes possible cooperation between time periods and cooperation between electricity and district-heating subsystems.

The results show that with energy storage the system cost is reduced by 0.8 million SEK for one year. Despite the reduction in system cost the shadow price will increase in some time periods. For example, in one time period the shadow is increased by about 100 %, i. e. from 63 to 127 SEK/MWh.

Shadow price analysis has also been applied in studies focused on the national system. Andersson et al (1992) have derived shadow prices for electricity in the Swedish system when the power demand approaches the maximal power generation capacity. The shadow prices show incentives for power reducing end-use measures. Karlsson et al (1995) have applied this shadow price analysis for studying the influence of different boundary conditions on the national system. The boundary conditions concern settlement of nuclear power, electricity export and import, end-use measures and environmental restrictions.

In *Paper IV* maximal system cost reductions for end-use measures have been calculated. Since cooperation is assumed the distributor and customers are regarded as one system. The end-use measures result in peak load reductions as well as increased electricity use. Important boundary conditions are the taxes for electricity and fossil fuel use since they are different for industrial and non-industrial customers. The difference in taxation will affect the profitability for end-use measures such as bivalent heating systems. The cooperating actors constitute of a distributor and six customers. The customers are represented by a hospital, an airport, a nursery garden, a waterworks, a radio tower and a

wholesale trade. The local market (50 000 inhabitants) represents a municipal system situated 200 km north west of Stockholm.

The results show that with cooperation end-use measures can reduce the system cost considerably for participating actors. Cooperation will yield system cost reductions for one year that range from 46 000 SEK (the hospital) to 1.3 million SEK (the nursery garden). The first cost reduction corresponds to 5 % of the original system cost and the second cost reduction to 50 % of the original system cost. In this case there is no investment costs included in the system cost reductions. However, investment costs have been estimated separately.

In *Paper V* the total system cost reduction for end-use measures is calculated for two cases. The first case represents a system cost reduction associated with the maximal power reduction capacity of identified end-use measures. The second case represents a system cost reduction associated with a specific load curve, in this case the load curve of 1994. The load curve of 1994 includes peak loads that are not as clear and distinct as assumed in the first case. Therefore, the maximal power reduction capacity can not be used in the second case. The local market (90 000 inhabitants) represents a municipal system situated about 150 km north of Stockholm. The cooperating actors constitute of a distributor and eleven customers. The customers are represented by different industries, a hospital, a warehouse, a waterworks, an ice-hockey arena, a harbour and a radio tower.

The results show that with a power reduction capacity of 8 642 kW the maximal cost reduction is 2.8 million SEK for one year. The cost reduction for the load curve of 1994 is 1.9 million SEK.

The system analyses presented in *Chapter 6* is a continuation of the analysis in *Paper V*, i. e. the system and the end-use measures are the same. The analysis in *Chapter 6* treats the profitability for end-use measures for other electricity prices and charges represented by an energy tariff and a regional grid tariff. In the grid and energy tariffs the total subscription charge is larger than in the high voltage tariff that is input data in the analysis presented in *Paper V*. On the other hand, the total power charge is lower in the new tariffs. The subscription charges are based on one or two power values while the power charge in the energy tariff is based on fifteen power values, distributed on the five winter months. The changes in subscription and power charges affect the system cost reduction associated with end-use measures.

The results show that the maximal cost reduction is 2.2 million SEK for one year. The cost reduction for the load curve of 1994 is 1.9 million SEK. The cost reductions are less, compared to the cost reductions obtained with the high voltage tariff (see *Paper V*). However, the probability for achieving the maximal

cost reduction will increase, as the total subscription charge is increased. On the other hand, the incentives for reducing peak loads for separate winter months will be reduced, since the total power charge is reduced.

2 Literature

2.1 Introduction

In this chapter different energy-system models and analyses will be referred to and discussed. In *Chapter 2.2* some references that describe the future Swedish electricity market will be presented. Results from analyses of the Swedish electricity system will be discussed as well as possible consequences of an increased electricity trade between the European countries. In many articles about energy-system analyses the terms demand elasticity, welfare maximisation (or total surplus), producers' surplus and customers' surplus are mentioned. In *Chapter 2.3* there are short explanations of these concepts. In *Chapter 2.4* various energy system models and analyses, from Sweden and other countries, are presented. In *Chapter 2.5* there are some concluding remarks on the contents of this thesis compared to the referred works.

2.2 The future electricity market

End-use measures. Karlsson et al (1995) have analysed the conditions for end-use measures with and without the Swedish nuclear power plants. Two cases representing the nuclear power settlement have been analysed. In the first case the nuclear power is settled rather late, which means that 5000 MW is settled in year 2005 and the other half is settled in year 2010. In the second case the settlement is started earlier, i. e. 2000 MW in year 2000, 3000 MW in year 2005 and finally 5000 MW in year 2010. The results show that if the nuclear power is settled and end-use measures are simultaneously introduced, the system cost is reduced by about 14 % or 30 billion SEK (10^9 SEK) for 25 years compared to the case where the nuclear power is settled without end-use measures. The cost reduction is equal for both the late and early settlement. If end-use measures are introduced and the nuclear power is not settled the results show that the system cost is reduced by 10 %, or 16 billion SEK. In these analyses it is assumed that there is no extension of the electricity transmission capacity from Sweden to other countries. It is assumed that there is an annual increase in electricity demand by 1 %. In Table 2.1 the optimal electric power and energy reduction for

load management and efficiency improvements in the industry are presented for five-year periods. The results represent all the cases, i. e. without settlement, late settlement and early settlement.

Table 2.1. Annual electric power and energy reduction in the industry.

<i>End-use measure</i>	<i>Years 1-5</i>	<i>Years 6-10</i>	<i>Years 11-15</i>	<i>Years 16-20</i>	<i>Years 21-25</i>
Load management: Power reduction (MW)	800	1300	1800	1900	1900
Efficiency improvement: Energy reduction (MWh)	0	6 000	12 000	13 000	14 000

If the electricity transmission capacity to countries in the northern part of the European Continent (included Denmark) is extended the potential for load management and energy-efficiency in the industry is the same. Thus, electricity import from the these countries will not replace end-use measures.

System analyses with somewhat changed conditions for the nuclear power have been performed by Henning et al (1996). In these analyses it is assumed that the electricity demand in Sweden is constant or decreasing during the 25 years. It is also assumed that the generation capacity of the nuclear power plants is lower and the economic life is shorter. Moreover, a special charge is added to the cost for nuclear power. The charge is assumed to cover insurance costs and costs for environmental effects. The analyses also include a case where only *two* nuclear power plants are settled. The results show that even with these conditions it is profitable to introduce end-use measures in the industry, both with and without the nuclear power plants. However, if the electricity demand is decreasing the optimal electric power and energy reduction from end-use measures is reduced.

Karlsson et al (1995) and Henning et al (1996) have included the power producers within the system boundaries. The results show that end-use measures are profitable also from the view of the national system. The optimal amount of end-use measures is increasing with time as can be seen in Table 2.1.

Cogeneration. New municipal cogeneration plants are profitable if the nuclear power plants are settled, according to Karlsson et al (1995). If the nuclear power plants are not settled, there is no need for new municipal cogeneration plants if

end-use measures are introduced. Henning et al (1996) show that with the changed conditions new municipal cogeneration plants are profitable only if there is a total settlement of the nuclear power plants before year 2020. If only two nuclear power plants are settled, new municipal cogeneration plants are not profitable.

Cogeneration plants can be profitable with existing conditions if the system is instead represented by the local market, and the tariff of the power producer is a boundary condition. However, if the tariff of the power producer deviates to a large extent from the marginal costs for electricity generation there will be a suboptimisation within the national system.

The optimisation model. The linear programming model *MODEST* has been used to perform these analyses (Henning, 1994). *MODEST* will be discussed in *Chapter 4.1* but is shortly mentioned here to describe the conditions for the representation of the national system. The model searches for an operating strategy of the national system that will minimise its system cost. The system cost consists of costs for electricity generation, distribution and also investment costs for new power plants, end-use measures and extended transmission capacity for electricity export and import.

Electricity customers are represented with three different customer categories, i. e. industries, housing and also service and commerce. The categories are represented for the north and the south part of Sweden.

The time division represents the short as well as long time perspectives. The year is divided into a number of time steps representing among other things peak loads. The analysis period of 25 years is divided into five periods, each representing five years, to enable the representation of an increased electricity demand in a longer time perspective.

Electricity trade with other countries. Within the European Union (EU) there is a work going on to integrating the electricity and gas markets in the inner market of EU (SOU 1995:14). As a first step EG's council in 1990 accepted two directions, one for price transparency and one for electricity transit. The price transparency direction implies that distributors must record contracted prices and agreements for industrial end-users. The electricity transit direction intend to facilitate the electricity trade between countries. In recent years the interest has been focused on Third Party Access (*TPA*). *TPA* implies that there is an obligation for the grid owner to transit electricity to anyone who demands it. Since there are big differences in electricity price between countries in Europe there is an incentive for electricity trade, see Tables 2.2 and 2.3. For the Swedish

electricity market the consequences of an increased trade will depend on, among other things, the size of the transmission capacity and the possibility for individual customers to freely choose power producers or distributors.

Table 2.2. Electricity prices in Swedish industries, 1993 (öre/kWh).¹

<i>Country</i>	<i>Small industries²</i>	<i>Medium-sized industries³</i>	<i>Large industries⁴</i>
Sweden	32	28	23

Table 2.3. Electricity prices in industries including taxes, 1993 (öre/kWh).⁵

<i>Countries</i>	<i>Small industries⁶</i>	<i>Medium-sized industries⁷</i>	<i>Large industries⁸</i>
The west of Germany	104	85	62
Portugal	94	84	66
Italy	91	71	43
Spain	87	73	59
Belgium	77	62	38
Luxembourg	76	50	38
The Netherlands	75	52	37
Ireland	73	56	44
France	68	56	39
Great Britain	67	50	-
Greece	59	55	39

Consequences of electricity trade between Sweden and other countries have been discussed (NUTEK, 1993). In a *short time perspective* it is assumed that the trade with Norway will play an important role for Sweden. Since Norway generally has lower prices than Sweden an increased trade with Norway will lower the Swedish prices. The trade with the countries on the northern part

¹ SOU (1995)

² 2 GWh/year

³ 50 GWh/year, 10 000 kW

⁴ 140 GWh/year, 20 000 kW

⁵ NUTEK (1993)

⁶ 1.25 GWh/year, 500 kW

⁷ 10 GWh/year, 2 500 kW

⁸ 70 GWh/year, 10 000 kW

of the Continent will not influence the Swedish market much because the existing transmission capacity is relatively small. However, there is a possibility for a small price increase as a result of the trade with these countries. In a *somewhat longer time perspective* it is assumed that Sweden, Norway and Finland will create a common Nordic electricity market as a result of similar market structures. Moreover, it is assumed that the competition for Swedish and Norwegian power will increase if Sweden and Norway extend their transmission capacity to the northern part of the European Continent. In a *medium-long time perspective* it is estimated that at least large industrial electricity customers and large distributors within EU will have the possibility to freely choose electricity producers and distributors. In this case it is also assumed that the transmission capacity from Sweden to the Continent is increased to a large extent. With these conditions the average price level in northern Europe will approach the German electricity price. Hence, in a longer time perspective the German electricity market will be important for the Swedish price level.

2.3 Demand elasticities and welfare maximisation

Elasticity of demand. In order to study the relationship between price and demand, the concept of price elasticity of demand E_d is often used, for instance by Lo et al (1991). E_d is defined as the ratio between the percentage change in demand ΔD and the percentage change in price Δp , i. e.

$$E_d = \Delta D \div \Delta p \quad (2.1)$$

Own-price elasticity and cross-price elasticity are often used when analysing the demand-side (Hjalmarsson and Veiderpass, 1986). The own-price elasticity describes the change in demand of a product as a result of a change in price of the *same* product. Own-price elasticities are usually negative, meaning that the demand of the product will decrease if the price is increased. With cross-price elasticity it is possible to study the relationship between two different products. It describes the change in demand of a product (with constant price) as a result of a change in price of *another* product.

By coupling price and demand by E_d it is possible to describe load shifting, or load management, between peak load and non-peak load periods. The elasticity concept is often used for calculating tariffs which aim at encouraging

load management measures. In *Chapter 2.4* articles will be referred to where own-price as well as cross-price elasticities have been used.

Total surplus approach. The concept of total surplus (W) is often used in the study of electricity pricing. W is defined as the difference between the customers' willingness to pay for a product and the producers' cost for supplying the product (Lipsey et al, 1990). W can also be defined as the sum of customers' surplus (CS) and producers' surplus (PS), i. e.

$$W = CS + PS \quad (2.2)$$

CS can be derived from the demand curve, see Fig. 2.1. The demand curve shows the price customers are willing to pay for each unit of a product, under the consideration that the products are bought one at a time. The area under the demand curve is equal to the customers' total valuation of the products consumed. However, the customers buy the products at the prevailing market price p , and not at different prices as illustrated by the demand curve. Therefore, CS is the area under the demand curve and above the price line describing p .

Figure 2.1. CS is the area under the demand curve and above the price line.

PS can be derived from the supply curve, see Fig. 2.2. The supply curve shows the producers' cost for producing one more product. The total cost representing a certain quantity is the area under the supply curve. PS is defined as the difference between the income of the products and the total cost of production. PS is therefore the area above the supply curve and below the line describing p .

Figure 2.2. *PS* is the area above the supply curve and below the price line.

W is maximised at the point where the demand and supply curves intersect, i. e. for the co-ordinates p and q in Fig. 2.3. This point represents the point of equilibrium in a competitive market and p is called the equilibrium price. If the quantity produced deviates from q , the sum of the two surpluses will not be maximal. If the quantity produced is q_1 the price the customers are willing to pay is higher than p , and the producers' cost for producing the products is lower than p . Consequently, customers are willing to purchase more products and producers will miss a return. If the quantity produced is q_2 the generation cost exceeds the revenue corresponding to p . For the customers the expenditure exceeds the value they are willing to pay.

Figure 2.3. The sum of *PS* and *CS* describes the total surplus, or W .

Maximisation of W is often used, with or without E_d , when electricity tariffs are designed, see e. g. Caramanis et al (1982), David and Li (1991^b), Lo et

al (1991) and McDonald et al (1994). When optimisation is applied in this thesis the objective is to minimise the system cost of a certain system with existing electricity prices and charges as boundary conditions.

2.4 Energy system models and analyses

Energy policy. A number of articles has been found describing energy systems in different countries. The articles deal with different system measures which aim at increasing the system efficiency in some aspect.

Schrøder Amundsen et al (1994) have investigated the potential for export of Norwegian hydropower. An integrated long-run equilibrium model has been constructed, which represents the northern European electricity market. The objective is to decide how much electricity that should be generated, exported and imported in different countries in order to maximise W in the northern part of Europe. The results show that without environmental taxes Norway, as well as other countries, should expand their generation and transmission capacity significantly. The transmission capacities from Norway to Germany and Denmark should be increased by 6 TWh each. Sweden should increase the transmission capacity to Denmark by 3 TWh. The consequences of two environmental taxes have been investigated. One of them is a CO_2 -tax which has been proposed by the European Commission. It corresponds to US\$ 10 per barrel crude oil. The other one is a tax for waste from coal-fired plants and nuclear power plants. The results show that if environmental taxes are added the electricity price is increased, and the demand for electricity in the northern European market will be reduced. However, Norway should increase the electricity generation slightly, compared to the reference scenario representing no taxes. In conclusion, the analyses show that there is a considerable potential for Norwegian electricity export, especially when there are European environmental taxes. The amount of electricity that is exported from Norway is however too small to significantly affect the electricity prices in northern Europe.

In these analyses the potential for end-use measures in the northern European market has not been discussed for the different cases.

How are the distributor and customers affected by end-use measures in systems where the electricity price deviates from the marginal cost? This is discussed by Sparrow et al (1993) by comparing the average cost for electricity (AC) and the marginal cost for electricity (MC) when there is surplus and

shortage of electricity. It is assumed that AC is equal to the distributor's price of electricity. *If* the electricity demand approaches maximum capacity of the distributor's system MC will be higher than AC . All customers will gain on end-use measures that reduce the electricity use. However, the incentives are not enough and the distributor must intervene to encourage these actions. *If* the electricity demand is well below maximum capacity AC will be higher than MC . If the electricity use is decreased, the reduction of the distributor's revenues will be larger than the reduction in costs, and end-use measures will not be profitable for the distributor. Thus, customers who have no end-use measures will not benefit from the effect of other customers' end-use measures. There is also a risk that too many end-use measures are introduced. When AC is higher than MC customers should instead introduce measures that imply increased electricity use, such as fuel-switching from fossil fuels to electricity. Finally, *if* AC is *equal* to MC the price signal to the customers will be correct and there will be an optimal amount of end-use measures.

In this article the systems have been defined in a similar way as in this thesis. When the authors reason about AC , AC can be said to describe a system where the system boundary separate distributor and customer. AC can not transfer all the necessary information to the customer about the state of the system. When the authors reason about MC , MC can be said to describe a system which includes the distributor and customer.

Sudhakara Reddy (1996) discusses the need for objective comparisons between the cost changes associated to end-use measures and new power generation plants. It is important to be able to evaluate the effects of end-use measures since they can avoid, or at least postpone, investments in new power generation plants. So-called avoided costs in the long time perspective are suggested as measures for such comparisons. End-use measures are profitable if the avoided costs associated to the end-use measures will reduce AC for electricity sales to the customer. AC is here defined as the annual revenue requirement divided by the total annual electricity generation. End-use measures should be seen as a resource in the energy system and consequently integrated into the planning process for the future energy system.

The purpose of the system analysis is somewhat different compared to the purpose in this thesis. The system is defined by the distributor and the measure of profitability is focused on revenue requirements, and not on the system cost.

Christiansson (1996) has investigated the ability for reducing future electricity demand for air distribution in Swedish commercial buildings. A forecasting model for long-term analysis of electricity demand has been used. The model is a so-called bottom-up model, i. e. the representation is focused on a

detailed description of energy flows, technological options and potentials for technical changes. The annual electricity demand is determined by the sectorial use of air distribution, new energy technologies, and future growth of floor stock. In contrast to optimisation models, where there is *one* optimal solution suggested, this model presents a *range* of decision alternatives, defined by different discount rates. A number of scenarios are developed to describe future electricity demand for air conditioning in commercial buildings. They include improved air control, electricity price increase and policy programs. The policy programs include information, end-use measures and introduction of best available technology. The results show that the future electricity demand for air conditioning can be reduced considerably by introducing policy programs, especially the one where best available technology is introduced. The results also show that the future demand is less sensitive to higher electricity prices.

The analysis focuses on a system that is defined by commercial buildings and their demand for air distribution. There is no cooperation considered between the electricity supply- and demand-sides.

Parikh et al (1996) have analysed barriers for introducing end-use measures in industries in India. The analysis includes variable speed drivers, industrial cogeneration and also energy efficient motors, fans and pumps. The major barriers for adoption of end-use measures are large investment costs, insufficient incentives and lack of information about how to introduce the end-use measures. The authors conclude that to overcome the barriers there must be a changed attitude towards end-use measures. Incentives for introducing end-use measures should be increased and tailored programs for individual industries should be worked out.

In this analysis there is no cooperation considered since the systems are defined by the customer systems. Consequently there is no consideration taken into costs for electricity distribution and/or generation.

An optimisation model for industrial systems including both energy and material flows (*MIND*) has been developed (Nilsson, 1993). The model is based on mixed-integer linear programming and describes linear as well as non-linear functions. The purpose with *MIND* is to find the optimal solution of the industry and to avoid suboptimisations for production, energy supply and energy recovery. The model has been used in several system analyses. For example, industrial production schedules in response to different electricity tariffs have been analysed (Nilsson and Söderström, 1993). Furthermore, cost-effective cooperation between a large industry and the local distributor has been investigated using *MIND* (Dag and Björk, 1996).

Busch and Eto (1996) suggest the use of avoided costs for electric utility demand-side planning, instead of the use of *MC*. Here the avoided cost describes a change in cost as a result of a *finite* change in load. In contrast, *MC* describes a change in cost as a result of an *infinitesimal* change in load. Avoided costs can be divided into generation avoided costs and non-generation avoided costs. Generation avoided costs are associated with operational costs for electricity generation and capacity costs for power generation plants. Non-generation avoided costs are associated with for instance reserve capacity. With end-use measures reserve capacity can be saved. Non-generation avoided costs are also energy and capacity costs for the transmission and distribution system. Energy costs associated with losses for transmission and distribution can be reduced by end-use measures. If end-use measures are introduced where new plants are planned, end-use measures can avoid or postpone the suggested investments. Non-generation avoided costs can also be externality costs, i. e. costs that are not reflected in the price of a product. Externality costs are for instance costs for environmental damage.

On the other hand, with *MC* there will be information about the state of the system in different time periods, showing small or large incentives for introducing end-use measures in a cost-effective way.

Vine (1996) has described the use of end-use measures in European countries. In Europe end-use measures have been applied for many years, especially in the residential sector, but also in the commercial and industrial sectors. In the residential and commercial sectors most programmes have focused on heating, lighting and air distribution. In the industrial sector programmes have been focused on, first of all, lighting but also cogeneration, heating, ventilation, air conditioning, interruptible loads and efficient motors. The author also discusses the role of end-use measures in deregulated markets. In deregulated markets energy systems will face new boundary conditions and the forming of strategies for end-use measures will change. In a competitive environment so-called non-energy reasons will also be important to end-use measures. Non-energy reasons are e. g. business development, environmental quality, public image and quality of service. End-use measures can be used by electric utilities with regard to retaining existing customers and for finding new ones.

Hollander and Schneider (1996) discusses two general viewpoints about the stimulation of energy efficiency, i. e. stimulation from the government or the unregulated market. Advocates to the first viewpoint hold that energy efficiency results in economic as well as environmental benefits and should be stimulated by the government. Advocates for the second viewpoint hold that an unregulated

electricity market will manage to stimulate increased productivity in general. Increased energy efficiency should be seen as a part of the increased productivity. During the last two decades there has been a great interest in increasing energy efficiency, according to the authors. Lately this interest has slowed down a bit since there is a tendency towards increased competition in the energy market and an expectation of lower energy prices. However, energy efficiency will be desirable for the society since it is important for the economy and environment. Economic progress and growth is among other things a result of technological changes and efficiency improvements. Furthermore, an important factor for the future of energy efficiency is research and development. The authors are of the opinion that the government and private sector should cooperate to stimulate new innovations in the area of energy efficiency.

The authors have not considered cooperation between actors as an incentive for increasing efficiency of energy use and reducing system costs.

Side-effects, or external effects, arise from production and use of goods and services. However, external effects are often not included in the price. Hence, the use of resources will not be optimal from the society's point of view. Carlsson (1996) has considered external effects associated with environment and employment in a system analysis of a municipal system (130 000 inhabitants). The calculations have been performed by using *MODEST* (Backlund, 1988), (Henning, 1994). The results show that large system cost reductions can be found for systems that also include external costs. If external costs are added to the original system the system cost is increased considerably, in this case from 2 to 4.2 billion SEK for 10 years. On the other hand, if external costs are included in the optimisation process the system cost is reduced by 40 %, or 2.5 billion SEK, compared to the case when the external costs are added to the original system cost. When external costs are included in the system analysis the use of biomass is largely increased while the use of fossil fuel is largely decreased.

The analysis shows that cost-effective energy systems can be designed by regarding relevant boundary conditions, including external effects.

Pricing of electricity. Also pricing of electricity is discussed by many authors. How should prices be set to optimise the use of electricity, encourage end-use measures and meet revenue requirements? How do customers respond to different tariff structures? Tariffs that are set for especially encouraging load management can be described as an indirect load control.

In this thesis, the aim has not been to calculate optimal electricity prices. Instead, the aim has been to study consequences for different degrees of cooperation between distributor and customers with an existing tariff (the tariff

of the power producer or distributor) as a boundary condition. However, both similar and deviating approaches can be found in the following articles.

Bohman (1991) discusses optimal electricity prices. In general, a price of a product has several functions. By means of the price different products can be expressed in a common unit, and by that compared with each other. The prices decide the size of the total payments. They can establish equilibrium between supply and demand. They create incentives for customers and producers to seek alternative solutions. Finally, they inform the customers about the costs for increasing or decreasing the consumption. To achieve a societal effective use of resources the price should be in accordance with the short range marginal cost, *SRMC*. In that case all the functions of the price are used, and it is possible to achieve efficient solutions for short and long time perspectives. However, there are arguments against momentary electricity pricing. For instance, there can be considerable transaction costs associated with momentary pricing. The price should be known in advance so that the customer can manage to make cost-effective decisions. For an optimal pricing the author suggests the following rule of thumb: the price should be set in accordance with expected *SRMC* and the price differentiation should be based on essential differences in expected *SRMC*. The pricing is profitable *if* the revenues will exceed the transaction costs for the price differentiation.

In this thesis *SRMC* has been used as a measure of incentives for introducing system measures in cooperation. *SRMC* depends, among other things, on the electricity prices and charges that are boundary conditions to the system analysis.

The concept of spot-pricing of electricity constitutes a basis for the evaluation of the real time pricing. Spot pricing means that the price for buying and selling electricity is determined by the supply and demand conditions that exist at the time electricity is bought or sold. An open market is created that ensures that the price is always right according to the prevailing situation.

Caramanis et al (1982) report on the advantages with spot pricing when load management is introduced. With spot pricing customers will utilise load management in a manner that will benefit both the customers and producers, i. e. there is a cooperation between the actors. The spot prices are derived from the *W* concept and will hence be the most efficient pricing principle for the society according to the authors. However, spot prices will be associated with high transaction costs since they are updated with very short time intervals. The authors suggest two simplified tariffs, i. e. the 24-hour update tariff and the time-of-use (*TOU*) tariff. The prices in the former tariff are updated once a day, while the prices in the latter tariff are updated more seldom, for instance once a year.

Caramanis (1982) has investigated the conditions for integrating spot pricing into system models which aim at long-term planning. In a long-time perspective investment decisions will play an important role for the pricing. For this reason a spot-price forecast is suggested that span over the time period of interest.

David and Li have performed several studies on real time pricing and customer responses. They have studied the customer response for two degrees of real time pricing using a system model based on the demand curve (Fig. 2.1) and E_d (David and Li, 1991^a). The two degrees of real time pricing are the day ahead tariff and the hourly spot-pricing tariff. The day ahead tariff will not present to the customer sudden changes until the next day. The spot-pricing tariff will on the other hand present sudden changes already the next hour. Thus, spot-pricing can have more positive effects on the generation and transmission systems. If there is a *planned* outage also the customer with a day ahead tariff will be informed in time to manage to alter the electricity demand.

A pricing principle based on real-time pricing does not include capital costs. However, David and Li (1993^a) suggest an expansion of this pricing principle by adding to MC for electricity generation a marginal cost for making one more megawatt of capacity available to the customers. Such a tariff would better reflect the total costs of the power producer according to the authors.

David and Li (1991^b) present a model for electricity supply in markets where power producers compete for the buyers. The model is based on the W concept and the cross-time elasticity. The problem is solved by using Lagrange method (Foulds, 1981). Lagrange method deals with optimisation of functions and constraints which are not necessarily linear. The model can represent dynamic characteristics, i. e. the demand in one time period also depends on the price in adjacent time periods. This representation enables analysis of load management measures. The subject is further discussed by David and Li (1993^b).

When real time pricing and load management is represented in system models it is important to incorporate so-called behavioural models for customers (David and Li, 1992). The model that they have used is built upon the concept of demand elasticity across time. To model customers' responses to changes in electricity price three customer categories have been defined. They are characterised by their ability to react on a change in price. The first category represents the customer who optimises electricity use over a long time period. The second category represents the customer who only considers the current time step and price when optimising electricity use. The third category represents the real world customer and the behaviour lies between the two first categories. For

the real world customer the time period includes time steps representing price sensitivity, and time steps representing little price sensitivity.

In this thesis real customers are analysed. It is assumed that the customers will introduce end-use measures if the end-use measures will reduce the system cost. What measures that will be introduced depend, among other things, on what electricity prices and charges that are boundary conditions and also what customer categories that exist in the system.

Lo et al (1991) have investigated two methods for calculating electricity tariffs for distributors. The tariffs are modelled to encourage load management measures for domestic customers. The methods are based on linear programming (*LP*) and total surplus, W . When using the *LP* method the objective is to optimise the revenue collected from the customers. When using the W method the objective is to maximise CS and PS . E_d is incorporated into the analyses to illustrate the willingness of customers for changing the load curve by using load management measures. The objective functions for both methods are subjected to constraints describing the financial targets of the distributor. The price during the peak load period of the day becomes higher with the *LP* method. Moreover, the *LP* method is somewhat easier to manipulate in order to obtain an effective pricing.

The tariffs derived cover only prices for the day and not for seasons. Price changes over seasons are important in, for instance, Sweden. Furthermore, the objective of the *LP* model is to optimise the revenue from the customers. Hence, the system analysis is focused on the distributor.

McDonald et al (1994^a) have developed a model for calculation of spot-prices. The model is based on the W concept and E_d . The objective is to jointly optimise the benefits of the power producer and the customer, hence cooperation is assumed. Constraints to the optimisation problem are energy and power balances, grid constraints and revenue reconciliation requirements. To satisfy the conditions given to the problem spot-prices and load management should be applied. The spot-price includes MC for fuel, maintenance and energy losses. Besides, there is a factor for price adjustment which is used to achieve revenue reconciliation. The spot-price also includes energy balance surcharge during generation shortfalls and grid constraint surcharge during level breaches. In the expression of the spot price E_d is included to reflect the willingness for reducing electricity demand by load management measures.

McDonald et al (1994^b) present two so-called building blocks that can be used to describe industrial processes. The building blocks are used to represent complete industrial systems. The two blocks describe the instantaneous process and the storage process. The instantaneous process does not have any storage

element. It is either on, at full load, or it is off. The storage process incorporates a storage element. It describes the possibility to store products for a certain time period before it is time for the next step in the production schedule. The representation of the whole industry is incorporated in a cost function of a dynamic programming algorithm. The algorithm is used to determine the optimal operating strategy on the basis of spot-prices. The objective is to optimise the benefits of both the customer and the power producer, i. e. cooperation is assumed.

The two building blocks offer a rather rough representation of the customer system compared to simulation model *STRATO*. *STRATO* includes five different load management strategies and also energy conversion, energy efficiency improvement and local electricity generation.

Dynamic programming, used by McDonald et al (1994^b), is used for optimising systems that include processes performed in stages, for example manufacturing processes (Foulds, 1981). Dynamic programming describes the system by an optimal *set* of decisions, i. e. one decision for each stage in the process. When *linear* programming is applied, as in this thesis, the objective is instead to look at the system as a whole and optimise only *one* performance measure.

Sheen et al (1994) have evaluated a *TOU* pricing model for load management programs in the energy system of Taiwan. The model considers *MC* for electricity generation as well as cross-price and own-price elasticities for the electricity customers. The cross-price elasticities are used to evaluate the relationship between electricity use in different time periods and consequently the willingness to reschedule the electricity use from peak load periods to non-peak load periods. The model is used for deriving prices for different time periods in a *TOU* tariff. The existing tariff (1991) consists of three price levels for one day. The levels represent peak load period, mid-peak load period and non-peak load period. The peak load period represents 6 hours and $p = 11$ cent/kWh. The mid-peak load period represents 8 hours and $p = 7$ cent/kWh. The non-peak load period represents 19 hours and $p = 3$ cent/kWh. In Taiwan the peak load period covers July to October. It has been shown that the existing *TOU* tariff does not fully reflect *MC* for electricity generation. It is found that there should be a greater difference between peak and non-peak load periods to increase the encouragement for industrial load management programmes. In Taiwan the use of electricity is increased rapidly due to the economic boom. The annual average growth rate of the electricity use has been about 10 % in recent years and end-use measures have become an interesting alternative to new power generation plants.

In this article the peak load period of the day represents quite a long time period in contrast to the peak load period in this thesis, which is represented by 5 hours for the whole year.

Outhred et al (1988) discuss a new pricing principle which incorporates so-called intertemporal linking. Intertemporal linking means that actions taken in certain operational strategies are affected by earlier decisions and will affect future decisions. Intertemporal linking is caused by storage of energy and material and also by start-up or shutdown sequences of power generation plants. In this pricing principle the price is the sum of *SRMC* and the term reflecting intertemporal linking, i. e. the marginal effect of a decision on the price forecast. This pricing principle is a compromise between a *TOU* tariff, where the prices are known in advance, and a spot-pricing tariff, where there is little forewarning for price variations.

With intertemporal linking the dynamic characteristics of the system is considered on both the supply- and demand-side. In this thesis dynamic characteristics have also discussed, among other things in *Paper III* where shadow prices for district-heating demand and energy storage are analysed.

Siddiqi et al (1993) suggest a pricing principle based on real-time pricing and outage costs. When there is no shortage of electricity the prices for all the customers are based on real-time pricing. When there is shortage the customers are charged *differently* according to their own outage costs. Customers who have high outage costs are charged with high prices. On the other hand, these customers will receive higher levels of service reliability. With this pricing principle the utility/distributor can act immediately at times of shortage by disconnecting loads according to the priority list. Loads associated with low outage costs are disconnected first.

The load priority system is, unlike in this thesis, based on power charges that are different between customers. In this thesis, prices and charges for electricity are equal for all the customers and based on the electricity tariff that is a boundary condition to the analysis. In spite of that the cost reductions will be different since the power reduction capacities will differ between the customers.

Transmission pricing. System analyses have also been performed to investigate the possibilities of increasing the cost-efficiency in the transmission system, i. e. the grid. *MC* and spot pricing have been suggested as indirect measures. In this thesis, the grid has not been represented separately. It is represented as a part of the total prices and charges that are boundary conditions to the specific systems.

Tabors (1994) discusses the importance of *MC* based pricing for the services on the grid. The grid is still a monopoly while in many countries

electricity generation and distribution work in competitive markets. According to Tabors, also the grid will in the future work in a competitive market. For optimal decisions concerning operating strategies and investments the grid owner should set prices according to the *MC* principle, even on the monopoly market. *MC* will indicate where power producers and customers should be located. *MC* will also show incentives for increasing the efficiency of electricity generation and electricity use.

Prices for the grid have also been discussed by Hunt and Shuttleworth (1993). They suggest that the pricing should be based on *MC* representing transmission losses and a rationing cost associated with constraints on the grid, such as thermal limits and voltage stability limits.

The conditions for spot pricing for the grid have been analysed by Bohn et al (1984). An efficient pricing should consider the stochastic changes in the electrical load flow patterns, which are caused by variations in demand as well as localisation of customers and power producers.

Linking of models. The procedure of linking different models which cover somewhat different aspects of the energy system have been investigated by some authors.

Wene (1996) describes a procedure for linking a macroeconomic model and a technical system model. The two models describe the system differently and with different precision. Changes in the system can imply feedback in the macro economic system and vice versa. The macroeconomic model treats the energy system as one part of the total macroeconomic system. The macroeconomic model can point out general changes in the system, but it can not point out how these changes should be carried out technically, and in detail. A technical system model can describe in detail technical alternatives and potentials. If the models are linked it will be possible to perform a joint analysis of the macroeconomy and energy systems. The linking procedure, which is called soft linking, implies feedback with information between the models. To be able to carry out this linking, that part of the system that is included in both models (i. e. the overlapping area) is described by a common language. In the common language there are common measuring points identified, such as energy flows. The two models are correctly linked if they yield identical results in these measuring points.

A linking of two models has also been performed by James et al (1986). The two models were originally developed independently to study the Australian energy system. They have different viewpoints on the system and by linking the two models the different viewpoints can be considered simultaneously. One of

the models describes the Australian economy on a large scale. The other model is a dynamic linear programming model which describes the Australian energy system divided into several regions. In that model, technologies for extracting, processing, converting and using energy are represented by costs and operating characteristics.

A linking procedure is also used between *MODEST* and *STRATO*. However, *MODEST* is not a macroeconomic model. *MODEST* is here used to describe a local energy market. *STRATO* is used to describe individual customer systems within the local market.

2.5 Concluding remark

In this literature review studies have been referred to that in some aspect are related to the work in this thesis. As a concluding remark to this chapter I will emphasise the purposes for this thesis shortly.

The aim is to identify possibilities for *system cost reductions* for customer and distributor systems, where existing electricity tariffs will serve as one of the boundary conditions. The analyses have been carried out for different degrees of cooperation between distributor and customers. The customers represent industries, water-works, hospitals, a warehouse, a water-purifying plant, a radio tower, an ice-hockey arena and a wholesale trade.

In the simulation model the systems are represented in a detailed way, i. e. with one-hour power demands. As a result of the detailed representation the simulation of end-use measures will be reflected in a realistic way. It is also possible to analyse the importance of cooperation when end-use measures are introduced. A number of real local markets have been analysed and system measures have been suggested. The optimisation model is used to derive *MC* for electricity and district heating within the local market. The model is also used to find the optimal size of new municipal cogeneration plants.

Even though this work is focused on the Swedish system, the general principles here presented should be easy to adapt to markets outside Sweden as well, especially for markets which have fairly similar conditions concerning electricity generation and climate conditions. Analyses of the Swedish system include a unique combination of the following factors: a temperature dependent electric load (electric heating in households), industrial activities, district-heating systems, large-scale cogeneration plants and supply of wood (as fuel for cogeneration plants).

3 The Swedish electricity market

3.1 The supply- and demand-side

Generation, use and trade. In Sweden the electricity supply system consists of hydroelectric power, nuclear power, back pressure power, condensing power, cogeneration power in district-heating systems, gas-turbine power and wind power. In Tables 3.1 to 3.4 information about electricity generation, use and trade during 1995 is presented (Svenska Kraftverksföreningen, 1996). However, it should be noted that the energy generation in the different plants vary between the years. During 1995 the hydroelectric and nuclear power plants generated together 93 % of the total electricity generation and about 7 % was generated in conventional thermal power plants. A small part was generated in wind power plants.

The largest customer category is the one that represents housing, service and district heating. Service includes offices, schools, business premises and hospitals. District-heating includes, among other things, electricity for heat pumps. This category used 1995 74.4 TWh electricity. Of this 30.3 TWh was used for electric space heating.

The industry, which is the second largest group, used 51.0 TWh. The largest group of industrial customers is the pulp and paper industry followed by the chemical industry, the engineering industry and the iron-, steel- and metal industry. However, the pulp and paper industry generates to a certain extent its own electricity with fuel that is derived in conjunction with the industrial production.

Today Sweden imports and exports electricity to and from the Nordic countries and Germany. The countries have different electricity generation systems and consequently different *MC* for electricity generation. Denmark has mainly coal-based thermal power plants. Finland has hydroelectric power plants, nuclear power plants and conventional thermal power plants. Norway has hydroelectric power plants. In Germany the greater part is generated by thermal power plants. During 1995 Sweden imported totally 7.7 TWh and 6.9 TWh came from Norway, see Table 3.4. Sweden exported totally 9.4 TWh. The largest amount was exported to Finland and the second largest was exported to Germany.

Table 3.1. Electricity generation in Sweden 1995.¹

<i>Power plant</i>	<i>Electricity generation (TWh)</i>
Hydroelectric power	67.0
Nuclear power	66.7
Industrial back pressure power	4.2
Condensing power	0.4
Cogeneration power	4.7
Gas-turbine power	0.2
Wind power	0.1
Total	143.3

Table 3.2. Electricity use for different customer categories 1995.¹

<i>Customer category</i>	<i>Electricity use (TWh)</i>
Industry	51.0
Communication	2.5
Housing, service, district heating etc.	74.4
Disconnectable power for electric boilers	4.7
Losses	9.0

Table 3.3. Electricity use of the largest groups of industries 1995.¹

<i>Group of industries</i>	<i>Electricity use (TWh)</i>
Pulp and paper industry	19.0
Iron-, steel- and metal industry	7.6
Engineering industry	6.6
Chemical industry	6.5

Table 3.4. Electricity trade 1995.¹

<i>Country</i>	<i>Import (TWh)</i>	<i>Export (TWh)</i>
Norway	6.9	1.2
Denmark	0.6	2.1
Finland	0.2	3.8
Germany	0.0	2.3
Total	7.7	9.4

¹ Svenska Kraftverksföreningen (1996)

The energy system is characterised by high investment costs and irreversibility. Irreversibility means that once a power plant has been built there is no alternative use than to generate electricity. A power plant has an economic life of at least 25 years, and in most cases it takes a long time to build a new power plant.

The supply system must be able to meet the electricity demand in the long as well as in the very short time perspective. Hydroelectric power plants and nuclear power plants have low operating costs and are therefore used for meeting the demand in the long time perspective. Electricity demand in the very short time perspective, i. e. during peak loads hours, is met by plants that have high running costs but lower capital costs. Such plants are oil condensing plants and gas turbine plants.

National systems can be described as power dimensioned or energy dimensioned. Denmark and Germany have supply systems which can be characterised as *power dimensioned* as they are mainly based on thermal power generation plants which are dimensioned for meeting the country's maximum *power* demand during the year. The Norwegian supply systems can be characterised as *energy dimensioned* since it is based on hydroelectric power plants. The Norwegian system is dimensioned for meeting *energy* demand also during years with little affluence in the power producing rivers. The Swedish supply system can to some extent be characterised as energy dimensioned as a large part of the supply system constitutes of hydroelectric power plants.

There are great advantages with electricity trade between systems mainly based on thermal power and systems mainly based on hydroelectric power. During years with little affluence in the rivers systems mainly based on thermal power plants exports electricity to systems mainly based on hydroelectric power plants. During years with good affluence in the rivers it is the reverse.

Demand-side. Different customer categories are characterised by different load profiles. The use of electricity in industries varies to some extent in a random way during working hours. The demand for hot-water supply varies over the day but not over the seasons. The demand for space heating depends strongly on the outdoor temperature and will consequently vary over the seasons. As mentioned earlier electricity is to a certain extent used for space heating. Temperature-depending loads and a random variation in electricity demand in industries are the basis for peak loads. Consequently, peak loads often occur in cold winter days, during working hours.

To illustrate the fact that peak loads in most cases do not coincide in time for customers and distributor the points of time for peak loads in a local market

are presented in Table 3.5. (The data presented in the table serve as a basis for the system analysis presented in *Paper V* and *Chapter 6*.) As can be seen, the peak loads occurred in different hours and days, but during the same month. Most industries had their peak loads before noon, between 9 a. m. and 11 a. m.

Table 3.5. The points of time for peak loads in a local market (1994).

<i>Actor</i>	<i>Day in January</i>	<i>Peak load hour</i>	<i>P_{peak} (kW)</i>
Hospital	18	11 a.m.	2608
Food industry	10	11 a. m.	1971
Food industry	19	9 a. m.	1728
Galvanising ind. ¹	11	11 a. m.	1737
Shopping centre	7	4 p. m.	1450
Saw mill	26	4 p. m.	1102
Electronics ind. ¹	18	10 a. m.	1254
Ice-hockey arena	13	9 p. m.	1004
Saw mill	28	10 a. m.	898
Office building	21	12 a. m.	860
Property manager	4	2 p. m.	614
Dairy	17	12 a. m.	560
Paper industry	17	11 a. m.	679
Harbour	11	9 a. m.	887
Furniture shop	7	5 p. m.	461
Bakery	6	11 p. m.	665
Water-works	17	11 p. m.	340
Warehouse	27	4 p. m.	452
Radio tower	27	2 p. m.	385
Distributor	18	6 p. m.	135 260

The shopping centre and the furniture shop had their peak loads in the afternoon, between 4 p. m. and 5 p. m. At this time of the day the number of visiting customers was probably large. The ice-hockey arena had its peak load in the evening at 9 p. m. possibly because there was an ice-hockey match taking place at that time.

¹ ind = industry

Power charges of distributors as well as power producers are mostly based on average values of the largest one-hour power values from separate winter days. To illustrate the distribution of large power values Table 3.6 shows the power values for the same distributor. The power values were the basis for the power charge of the power producer. As can be seen, most of the values occurred in the afternoon or early evening.

Table 3.6. The points of time for power values of the distributor that are the basis for the power charge of the power producer (1994).

<i>Month</i>	<i>P no. 1 (MW)</i>	<i>Day</i>	<i>Hour</i>	<i>P no. 2 (MW)</i>	<i>Day</i>	<i>Hour</i>	<i>P no. 3 (MW)</i>	<i>Day</i>	<i>Hour</i>
Jan.	135	18	6 p. m.	132	17	6 p. m.	130	19	9 a. m.
Feb.	127	23	11 a. m.	126	4	6 p. m.	126	22	7 p. m.
Mar.	129	2	10 a. m.	122	1	7 p. m.	119	3	7 p. m.
Nov.	120	30	5 p. m.	116	17	5 p. m.	116	29	6 p. m.
Dec.	123	22	4 p. m.	122	15	5 p. m.	122	13	6 p. m.

3.2 The deregulated market

Before the deregulation of the electricity market the distributor only needed one agreement for electricity purchase, which was represented by the high voltage tariff. The high voltage tariff consisted of four cost elements, i. e. energy price, subscription charge, power charge and fixed charge. The energy price was the expected *SRMC*, plus the cost for transmission losses. The energy prices varied over the day and the season according to Table 3.7. The subscription charge represented the power cost for local electricity distribution. The demand charge represented the cost for central electricity distribution and peak loads during the winter months. The fixed charge represented the cost for measurement and administrative activities.

After the deregulation generation and selling was separated from transmission. Actors who generate and sell electricity must now compete for the customers. Transmission of electricity is however still on a monopoly market. As a consequence of the division of the market the customer faces two tariffs, i. e. one for the electrical energy and one for the transmission.

Table 3.7. Time division and approximate energy prices for a power producer.

<i>Time division</i>	<i>Approximate energy prices (SEK/MWh)</i>
November to March	300
Workday 6 a. m. - 10 p. m.	
Remaining time (nights, weekends)	
April, September and October	170
Workday 6 a. m. - 10 p. m.	
Remaining time (nights, weekends)	
May to August	110
Workday 6 a. m. - 10 p. m.	
Remaining time (nights, weekends)	
	90

The greater part of the *energy* prices in the high voltage tariff is now represented in the energy tariff (SOU, 1995). A smaller part, which corresponds to marginal transmission losses, is represented in the grid tariff. The greater part of the previous *power charge* is represented in the grid tariff.

The levels of prices and charges as well as time division of prices in the energy tariff can be affected by means of negotiation with the seller. Moreover, the customer can choose the power producer or distributor who can give the most favourable agreement. Buyer and seller do not have to be located close to each other. The agreement for energy supply will regulate when the seller must provide electricity on the grid.

The grid tariff includes costs for transmission from the national grid via interjacent grids to the place where the electricity will be used. Since the transmission business is on a monopoly market, these prices and charges are fixed.

The grid is divided into three different systems: national grid, regional grids and local grids. The national grid is to the greatest part owned by the State, by means of Svenska Kraftnät. The regional grids are owned by power companies while local grids are mostly owned by local distribution companies.

A greater part of the costs of grid companies constitute of capital costs. The final cost level of the grid tariff depends, among other things, on the way the company calculates capital costs (SOU, 1995). The individual company has also the possibility to decide how other grid tariffs shall be represented in the company's own tariff. Consequently, grid tariffs from different grid companies can differ from each other. The grid authority (Nätmyndigheten) at NUTEK is

responsible for the transmission business in the deregulated electricity market. Some of the assignments of the authority is to see that prices and charges in the grid tariffs are reasonable.

An energy tariff of a power producer and a grid tariff representing a regional grid are further discussed in *Chapter 6*.

3.3 Pricing of electricity

The pricing of electricity is important for how much electricity that will be used in different time periods and in comparison with fuels. The pricing must consider the different characteristics of a national system as good as possible so that the scarce resources can be used economically. In principal the pricing can be based on either future costs or retrospective costs.

Future costs are either short range marginal cost, *SRMC*, or long range marginal cost, *LRMC*. *SRMC* describes the balance between supply and demand in the short time perspective. It represents the cost for generating the last kilowatt hour in the existing system. *SRMC* can be described as follows:

$$SRMC = RC + CC \quad (3.1)$$

where *RC* is the running cost and *CC* is the capacity cost. *CC* describes how much of the electricity capacity that is utilised at the time. If there is much capacity left, *CC* will be zero. If the power demand approaches maximum electricity generation capacity, *CC* will represent a high value. *SRMC* does not consider capital costs since there can be no new investments in a short time perspective. Capital costs are regarded as sunk costs that should not affect the present and future demand for electricity. Theoretically, with *SRMC* the customer can decide whether it is worth paying for the start of one more power plant or if there are other alternatives such as measures on the demand-side.

In the long time perspective expansion of the electricity generation capacity is possible. *LRMC* that describes the balance between supply and demand in the long time perspective consists of capital costs for future plants. When $SRMC \geq LRMC$ there is a need for new power generation plants or end-use measures. *LRMC* is an investment criterion rather than a pricing principle.

Electricity pricing based on *retrospective costs* include capital costs for *existing* plants. Hence, previous investments will affect present and future demand.

Different pricing principles will result in different ways of utilising the system and its scarce resources. A pricing based on *MC* will give signals to the customer on how to use the existing and future system effectively. A pricing based on retrospective costs will give less information about the prevailing situation of the system.

If the power demand approaches maximum capacity the probability for electricity shortage will increase. If the pricing is based on retrospective costs the customer will not be aware of the real costs for electricity. At that time the electricity prices will be too low compared to the real costs for electricity. The low prices will favour rather than moderate a large power demand. A similar effect arises if the time differentiation of the tariff is too small compared to the real cost variation. A small time differentiation affects the system particularly during winter days when the cost for electricity can show great variations. If the prices are constant over a too long time period customers will face prices that are below the true electricity generation costs during peak load periods, and above the electricity generation costs during non-peak load periods. Consequently, too much electricity will be used during peak load periods, and too little electricity will be used during non-peak load periods.

If the pricing is based on *MC* the prices will increase when the demand approaches maximum capacity. The increased prices will then moderate the demand, and consequently the probability for electricity shortage will decrease.

The pricing will affect the influence of end-use measures on the energy system. A pricing that is based on retrospective costs will give little information about how to use end-use measures in a cost-efficient way for the existing and future local market. With such a pricing there is a risk for suboptimisation within the local market if end-use measures are introduced. A pricing that is based on *MC* will show, for instance, when the system approaches maximum capacity and thereby indicate when power reducing end-use measures will be cost-effective. In this case there will be no suboptimisation within the system.

3.4 Taxes and charges

The final cost for electricity and fuel also includes taxes and charges (NUTEK, 1996). Taxes and charges differ between customer categories and between fuels.

To the electricity price an electricity tax is added. However, industrial customers do not have to pay this tax. To the fuel price cost elements such as

energy tax, CO_2 -tax, NO_x -charge and sulphur charge are added. When industrial customers use fuel for heat generation they do not have to pay the energy tax. Besides, they only pay 25 % of the CO_2 -tax.

Thus the total running cost for electricity and fuel use is lower for industrial customers than for non-industrial customers. The profitability for end-use measures that imply both electricity and fuel use (for instance bivalent heating systems) will therefore be different for industrial and non-industrial customers.

The tax rate for energy tax and CO_2 -tax is zero for fuels that are used for electricity generation. In a cogeneration plant, where electricity and district heating are generated simultaneously, the district-heating generation is subjected to an energy tax of half the normal value.

Taxes and charges used in the calculations are presented in the papers enclosed.

4 System models for distributor and customer

4.1 MODEST

Introduction. *MODEST* (Henning, 1994) is used to optimise the energy supply of a distributor system, with or without *new* plants for electricity and district-heating generation and *new* end-use measures. The system is in the model represented by linear relations. The relations describe the objective function, which is the discounted system cost, and boundary conditions. The system cost consists of costs for operation and costs for new plants and end-use measures. The boundary conditions describe restrictions in the system and energy demand. Restrictions are e. g. efficiencies and electricity generation capacities. The objective of the optimisation is to minimise the discounted system cost, under the consideration that variables take values that will satisfy all the boundary conditions.

Input data are for instance energy demand, divided into different time periods of the day and year, and technical data of the plants. General economical input data are prices and charges for electricity purchase from the power producer, fuel prices, taxes, environmental charges, maintenance costs, interest rate, price increases, time period of analysis and investment costs per megawatt for new plants. The model will decide the size of new plants and, by that, the total investment cost.

MODEST, which is a programme written in Pascal, generates input files to the commercial optimisation programme Lamps from AMS Ltd (Lamps user guide, 1991). It is in the Pascal programme the very system and its input data are defined. The optimisations have been carried out on a DEC 5500 work station.

Mathematical relationships. The system is in the model regarded as a network of nodes and branches, see Fig. 4.1. The nodes represent purchase of electricity and fuel, electricity generation, district-heating generation, energy storage, electricity end-use, district-heating end-use, etc. The branches represent energy flows between the nodes. The most important mathematical relationships are described below.

Figure 4.1. Representation of a system consisting of electricity and district-heating loads. These nodes and branches represent the municipal energy system which is the basis for the analyses in *Papers I-III*.

Power balance. The output power of a plant $P_{out,i}$ for a specific time period i is equal to the input power for the same time period $P_{in,i}$ multiplied by the efficiency of the plant η .

$$P_{out,i} - \eta P_{in,i} = 0 \quad (4.1)$$

Dimensioning. The size of a *new* plant P_{size} is defined by the largest output of that plant during the year. Consequently $P_{out,i}$ for the new plant must be less or equal to P_{size} , i. e.

$$P_{out,i} - P_{size} \leq 0 \quad (4.2)$$

Maximal output. The electricity generation capacity of an *existing* plant P_{plant} is restricted by the maximal capacity of the plant, here denoted by the constant m . P_{plant} must be less or equal to m , i. e.

$$P_{plant} \leq m \quad (4.3)$$

Fixed relation between flows. A fixed relation between two flows exists in a cogeneration plant where heat and electricity are generated simultaneously. The relation between electricity and heat output $P_{el,i}$ and $P_{h,i}$ is decided by the cogeneration ratio α as follows:

$$P_{el,i} - \alpha P_{h,i} = 0 \quad (4.4)$$

The value of α depends on the type of cogeneration plant. For a steam plant and a gas-turbine plant with waste-heat boiler α is approximately 0.50 but for a combined gas-steam plant α is approximately 1.0.

Energy demand. Energy demand for a certain time period q_i is met by energy from the grid or district-heating network $Q_{net,i}$. The efficiency of the grid or net η_{trans} represents losses for transmitting energy to the customers.

$$\eta_{trans} Q_{net,i} = q_i \quad (4.5)$$

Energy storage. Energy storage is described by equations for energy balance, dimensioning and maximal storage capacity. Energy can be stored between day and night and also between hours of a day. The storage is in the model taken into operation if it reduces the system cost.

System cost. The discounted system cost $C_{(b)system,d}$ for the distributor d representing the total length (b) of the time period is calculated as follows:

$$C_{(b)system,d} = C_{(b)energy,d} + C_{(b)power,d} + C_{(b)inv,d} + C_{(b)fix,d} \quad (4.6)$$

where $C_{(b)energy,d}$ represents discounted energy costs for electricity and district-heating subsystems. $C_{(b)energy,d}$ also includes maintenance costs for electricity and district-heating generation. $C_{(b)power,d}$ represents discounted power costs for the distributor's peak loads and power subscription. (Charges for power and subscription are in *MODEST* based on the maximal power demand of the year.) $C_{(b)inv,d}$ represents discounted investment costs and $C_{(b)fix,d}$ represents discounted fixed costs. $C_{(b)fix,d}$ includes for instance costs associated with individual plants or electricity tariff of the power producer and is independent of system operation.

In the model the annual costs are discounted to the beginning of b , using the net present value method (Andersson, G., 1984). The annual cost of a certain year n is multiplied by the net present factor, $NP_{r,n}$ see Eq. (4.7), where r is the interest rate. To obtain the final, total cost of a certain cost element the discounted costs of the different years are added. If there is an annual price increase j , the net present sum $NPS_{r,b,j}$ is calculated according to Eq. (4.8).

$$NP_{r,n} = (1 + r)^{-n} \quad (4.7)$$

$$NPS_{r,b,j} = \sum_{n=1}^b [NP_{r,n} (1 + j)^{n-1}] \quad (4.8)$$

New investments are assumed to occur at the beginning of the analysis period. The value of the investments are assumed to decrease linearly during the economic life l . If l is longer than b there will be a remaining value of the investment at the end of year b which will be considered in $C_{(b)system,d}$. The remaining value of the investment is discounted to the beginning of the analysis period, and subtracted from the original investment cost I , i. e.

$$C_{(b)inv,d} = I \{ 1 - NP_{r,b} [(l - b) \div l] \} \quad (4.9)$$

Time division. Each year is in the model divided into 28 time steps of different lengths to reflect the variation in energy demand during days and seasons. The time division is presented in Table 4.1. It is necessary to reflect the variation in

Table 4.1. Time division for one year in the optimisation model *MODEST*.

<i>Season</i>	<i>Day</i>	<i>No</i>	<i>Hour</i>	<i>Hours/year</i>
Winter : November to March	Work day	1	6 a. m. to 7 a. m.	98
		2	7 a. m. to 8 a. m.	98
		3	8 a. m. to 4 p. m.	686
		4	<i>P.l.h.</i> ¹	98
		5	4 p. m. to 10 p. m.	490
		6	<i>P.l.h.</i> ¹	98
		7	10 p. m. to 6 a. m.	784
	Peak load days	8	6 a. m. to 7 a. m.	5
		9	7 a. m. to 8 a. m.	5
		10	8 a. m. to 4 p. m.	35
		11	<i>P.l.h.</i> ¹	5
		12	4 p. m. to 10 p. m.	25
		13	<i>P.l.h.</i> ¹	5
		14	10 p. m. to 6 a. m.	40
	Weekend	15	6 a. m. to 10 p. m.	768
		16	10 p. m. to 6 a. m.	384
Spring & autumn: April, September & October	Work day	17	6 a. m. to 10 p. m.	992
		18	10 p. m. to 6 a. m.	496
	Weekend	19	6 a. m. to 10 p. m.	464
		20	10 p. m. to 6 a. m.	232
Summer : May, June and August	Work day	21	6 a. m. to 10 p. m.	1008
		22	10 p. m. to 6 a. m.	504
	Weekend	23	6 a. m. to 10 p. m.	464
		24	10 p. m. to 6 a. m.	232
Summer, vacation : July	Work day	25	6 a. m. to 10 p. m.	352
		26	10 p. m. to 6 a. m.	176
	Weekend	27	6 a. m. to 10 p. m.	144
		28	10 p. m. to 6 a. m.	72

¹ P.l. h. = Peak load hour during previous time period.

power demand particularly during cold winter days when peak loads appear. Peak loads cause very high MC values in the distributor system. Therefore, the winter days have a more detailed time division including peak load hours, and likewise five separate peak load days.

4.2 Shadow prices

A linear optimisation problem is described by Eq. (4.10), where $C^T x$ is the objective function describing the discounted system cost. The A matrix contains information about system components such as efficiencies and α values. The B vector contains information about electricity demand, district heating demand and maximum capacity of system components. The x vector represents energy flows from purchase and generation to end-use. The x vector also defines the size of new plants.

$$\text{Minimise } C^T x \quad \text{subject to } Ax = B, x \geq 0 \quad (4.10)$$

When linear programming is used, valuable information about the optimal solution is obtained from shadow prices Y_i (Williams, 1991). Y_i represents the effect of a small change in B on the optimal value of $C^T x$. Y_i can be interpreted as MC since Y_i indicate the marginal change of $C^T x$ as a result of a change in demand.

Y_i is closely related to the formulation of $C^T x$ and the representation of the system. If the system includes plants that connect subsystems and/or time periods, a change in B can also cause changes in these other parts of the system or time periods. Hence Y_i can be used for studying effects of connections in the system.

Plants that connect different parts of the system are e. g. heat pumps and cogeneration plants. The heat pump uses electricity for heat generation. The cogeneration plants generates heat and electricity simultaneously. Consequently, the heat pump and the cogeneration plant will connect the electricity and district-heating systems. The hot-water accumulator stores heat from one time period to another and thus connects different time periods with each other. The influence of conventional heating plants, cogeneration plants and hot water accumulators on Y_i is discussed in *Paper III*. The influence of a heat pump on Y_i is discussed below.

The influence of a heat pump on Y_i . In this example there is a municipal system consisting of the two subsystems for electricity and district-heating. One of the plants for district-heating generation is a heat pump. Electricity is purchased from a power producer and, by the distributor, sold to electricity customers but also used for heat generation in the heat pump.

If the electricity demand from the customers is increased, and also MC for electricity, it can sometimes be profitable to meet the increased demand by electricity which was first meant for the heat pump. In that case heat must be generated in another heating plant where capacity is left. This heating plant will often be characterised by an operating cost which is higher than the operating cost of the heat pump.

The electricity use is redistributed within the system and the use of fuel for heat generation is increased. The additional heat generation will be reflected by Y_i for electricity according to the following equation:

$$Y_i = (p_h \div \eta) \phi - p_{heat\ pump} \quad (4.11)$$

where p_h is the price including possible taxes and environmental charges for the fuel, ϕ is the coefficient of performance of the heat pump and $p_{heat\ pump}$ represents tax and maintenance costs for using the heat pump. The tax is added to the electricity price when the electricity is used for the supply of electricity, gas, heat or water (Svenska Kraftverksföreningen, 1995).

The following example illustrates a result which was received from optimisation with *MODEST*. The municipal energy system supplies electricity and district heating. The district-heating system includes, among other things, a heat pump and oil-fired boilers. The system components in the municipal energy system are described in detail by Henning (1994, pp. 95-100). If $p_h = 217$ SEK/MWh fuel (oil-fired boiler), $\eta = 0.90$, $\phi = 3$ and $p_{heat\ pump} = 83$ SEK/MWh electricity then $Y_i = 640$ SEK/MWh electricity. This value of Y_i for electricity is about twice as high as the value of Y_i reflecting the energy price of the power producer.

4.3 STRATO

Introduction. *STRATO* is based on *INDSIM* (Björk, 1989). The difference between *STRATO* and *INDSIM* is that with *STRATO* it is possible to calculate a discounted system cost for a longer time period than one year. *STRATO* also

consists of a procedure for comparison of the profitability for different combinations of end-use measure. The procedures added in *STRATO* are explained in detail later in this chapter. The programme is written in Turbo Pascal+ version 3 for *PC*.

Base procedures. The customer is in the model represented by, among other things, measured one-hour power data of total load and loads of specific processes. The simulation is based on one-hour power values of one year. However, it is quite unpractical to measure the electricity use for a whole year. A sufficiently long time period for measuring the use in, for instance, industries is one week. During one week the most important characteristics of the load profile will be identified for most industries (Björk, 1989). The model then creates a load profile representing one year on the basis of the measured data. It is also possible to create a one-year load curve from power data representing one day. On the other hand, with a load profile of one day it is likely that important information about the electricity use will be lost.

It is not sure that peak loads will be included among the recorded data. Peak loads are important for getting accurate power costs. To compensate the lack of peak loads the power values P are in the model multiplied by the factor RF (Björk, 1989) when the load profile of one year is created. RF is calculated as follows:

$$RF = [P_{rec} + Rand (P_{peak} - P_{rec})] \div P_{rec} \quad (4.12)$$

where P_{rec} is the largest power value among recorded data and P_{peak} is the largest power value of the year. $Rand$ is a random variable which can take values between 0 and 1. If $Rand = 0$ then $RF = 1$, according to Eq. (4.12). Accordingly, if $Rand = 1$ then $RF = P_{peak} \div P_{rec}$. By using RF the 52 weeks will differ from each other despite the fact that they are based on data from one week. In the model it is also possible to specify a summer month, representing the holiday month July, when the electricity demand is lower compared to other months.

General input data are electrical energy prices, power and subscription charges and interest rate. The cost for large power demands is based on an average power value. The cost for subscribed power can be based on an average power value or a fixed power value decided in advance. By this, it is possible to imitate real power costs quite well. In the model energy prices are specified hour by hour for, at the most, 12 time periods of the year.

Various types of end-use measure can be simulated. These are load management, local electricity generation, energy conversion and energy

efficiency improvement. Load management can be simulated as load priority system, time rescheduling of individual processes, bivalent heating system and energy storage. There are specific input data needed for simulating end-use measures. Such data are e. g. costs for fuel, investment and maintenance but also efficiencies of boilers, coefficient of performance measures for refrigerating machines, storage capacities and storage losses.

Load priority system. In a load priority system loads are disconnected or time rescheduled in a certain order of priority. The load priority system is taken into operation when the power demand exceeds a certain power limit which is defined in advance.

Loads suitable for load priority systems are electricity-based heating and cooling processes that are characterised by low heat or cool losses during short time periods. Such loads are e. g. galvanising pans, industrial furnaces, industrial washing machines, cool compressors and also space heating and hot water supply. Other suitable loads are car-engine preheaters and fans in ventilation systems.

Ten loads can at the most be included in the model. For each load a time period (minutes per hour) is specified during which the load can be disconnected. The power value which is defined as a limit for operating the load priority system is the same for all months.

There are three alternatives for operating the load priority system. The first alternative implies that the amount of energy that is disconnected will return to the system the next hour. In this case there is no change in the total energy use of the customer. However, such a strategy may create a situation where an even larger peak load is arisen. The second alternative implies that the amount of energy that is disconnected will return the next hour *only* if it will not create a new peak load. In this case there can be a small reduction in energy use. The third alternative implies that the amount of energy that is disconnected will not return to the system the next hour. With this strategy there will always be a reduction in energy use.

Time rescheduling. A whole process, or part of a process, can be rescheduled a number of hours or days in order to avoid peak loads. For instance, in *Paper V* there is a spray-painting line described which is in operation only a few days per month. The line has a large power demand compared to the total power demand of the industry. By time rescheduling the line large power costs can be avoided.

The simulation requires a data file of measured one-hour power values of one week representing the process that is rescheduled.

Bivalent heating. If there is a heat load, a bivalent heating system can be introduced. Heat is generated by either an electric boiler or a fuel-based boiler. The electric boiler is in operation when the operational cost of that boiler is lower than the operational cost of the fuel-based boiler, and vice versa.

Bivalent heating can be profitable within countries where the electricity price varies round, for instance, the oil price. In countries where the electricity price always is higher than the fuel prices bivalent heating based on electricity and fuel can, of course, not be profitable. (As can be seen in Tables 2.2 and 2.3 electricity prices on the Continent are higher than in Sweden.)

Energy storage. If there is a demand for heat or cool, an energy storage can be introduced. Heat and cool can then be produced at another occasion than during the time period when the demand exists.

Storage can also include other things than heat or cool. For instance, in the industrial production certain products can be produced when the electricity price is low, and stored until it is time for the products to enter the production again.

The time period for charging the storage is defined to the model in advance. Besides, measured power data for one week representing the operating time of for instance boilers or cool compressors are also needed.

Electricity generation. Peak loads can be reduced by electricity generation in customer systems. Electricity can be generated in reserve power plants or in small-scale cogeneration plant. Reserve power plants can be found for instance at hospitals. Small-scale cogeneration plants can be found in customer systems who can derive their own fuel in conjunction with the industrial processes. Such systems are wood industries, pulp and paper industries and water-purifying plants. The electricity generated can either be used by the customer who owns the small-scale cogeneration plant or fed to the grid for being sold to other customers.

In the model electricity can be generated continuously or under the condition that the operating cost of the plant is lower than the cost for electricity purchase.

Efficiency improvements. Efficiency measures will lead to a reduction in energy use. If the load profile of the device whose efficiency is increased contributes to peak loads the measure will also reduce peak loads.

Efficiency improvement is often a result of new, more energy-efficient machinery. The new machinery need a smaller amount of energy for each unit produced. On the other hand, the new machinery will probably produce a larger

amount of units. Efficiency improvement can also be obtained by introducing speed control of motors and by reducing idle load.

When simulating energy efficiency a percentage power reduction is specified. The power reduction is then used for each hour during the year.

Energy conversion. Energy conversion means that electricity is used for energy supply to a process instead of fuel, or vice versa. Here, as for efficiency measures, both energy and power demands will be affected, under the condition that the load profile of the process that is converted contributes to peak loads. What direction the conversion takes depends on prices, taxes and charges of electricity and fuels.

Loads suitable for energy conversion are different types of heating process, e. g. space heating, heating of hot-water supply and heating of industrial furnaces.

Measured power data for one week representing the energy demand of the process are needed for the simulations.

Investment costs. Investment costs for end-use measures vary substantially and depend on type of end-use measure. Most load management measures, some efficiency measures and electricity generation in existing reserve power plants require equipment for measurement and control of power demand. Energy conversion, efficiency improvement, local electricity generation in small-scale cogeneration plants and some load management measures (i. e. energy storage and bivalent heating) also require new plants and therefore demand relatively large investment costs. However, it is also possible that equipment needed for suggested end-use measures already exist in the customers' systems. In that case, investment costs can be relatively low.

Discounted system cost (STRATO). The discounted system cost $C_{(b)system,c}$ of the customer system c has the same cost elements as exist in $C_{(b)system,d}$ (see Eq. 4.6). However, the cost elements of $C_{(b)system,c}$ are representing costs that reflect the individual customer system. $C_{(b)system,c}$ is expressed as follows:

$$C_{(b)system,c} = C_{(b)energy,c} + C_{(b)power,c} + C_{(b)inv,c} + C_{(b)fix,c} \quad (4.13)$$

The maintenance cost for end-use measures can either be considered as a running cost, and included in $C_{(b)energy,c}$ or $C_{(b)fuel,c}$, or as a fixed cost, and included in $C_{(b)inv,c}$ or $C_{(b)fix,c}$.

The value of new investments at the end of b is calculated in the same way as in *MODEST*, i. e. with linear depreciation, see Eq. (4.9). If l is shorter than b it is assumed that the investment is done again, at the time there is no economic value left of the first investment. In that case $C_{(b)inv,c}$ is calculated according to Eqs. (4.14) and (4.15), where $C_{(b)inv,c}^*$ is the value of the second investment.

$$C_{(b)inv,c} = I + C_{(b)inv,c}^* NP_{r,l} \quad (4.14)$$

$$C_{(b)inv,c}^* = I \{ (1 - NP_{r,b}) [(l - b) \div l] \} \quad (4.15)$$

If a proper value of l can not be found at the time, the simulation can be done without the term $C_{(b)inv,c}$. The difference in discounted system costs, before and after the introduction of end-use measures, must then be interpreted with this in mind, i. e. the difference in system costs will also include future investment costs.

When different types of end-use measure are simulated for a customer system the purpose is to find the measure or combination of measures that will yield the lowest value of $C_{(b)system,c}$. To find the best strategy there is a possibility to automatically simulate all combinations of measures that are defined. $C_{(b)system,c}$ for all the combinations are compared with each other and with the reference cost, i. e. $C_{(b)system,c}$ for the existing system. The end-use measure, or combination of end-use measures, which in comparison with the reference case yields the lowest value of $C_{(b)system,c}$ is, of course, the most profitable one.

5 Analysis and calculation procedures

5.1 Lack of cooperation

As mentioned earlier, a reduction of the peak load in a customer system will not necessarily lead to a reduction of the peak load in the distributor system. This phenomenon, which is here called lack of cooperation, is described in the system analysis by a market with separate systems, see Fig. 5.1. When end-use measures are introduced without cooperation the purpose will be to minimise the system cost of the individual customer, and not the system cost of the local market.

Figure 5.1. Lack of cooperation. Actors are regarded as separate systems.

STRATO is used for studying the effects of introducing end-use measures without cooperation between distributor and customer. Prices and charges for electricity purchase to the customer system are input data to the simulation. To see how the distributor is affected by the end-use measures the difference in the distributor's costs for electricity $\Delta C_{el,d}$ is calculated, using *STRATO* and existing procedures for altering the load profile of the distributor system. The distributor system is simulated for the original load profile $L_{d,1}$ and the load profile including the end-use measures $L_{d,2}$. $L_{d,2}$ can be expressed as follows:

$$L_{d,2} = L_{d,1} - L_{c,1} + L_{c,2} \quad (5.1)$$

where $L_{c,1}$ is the summarised load profile of the customers before they have introduced end-use measures and $L_{c,2}$ is the summarised load profile of the customers after they have introduced end-use measures.

The distributor will experience a reduction in revenues since the customers have reduced their costs for electricity purchase. The total change in revenues ΔR_d is calculated as follows:

$$\Delta R_d = \sum C_{el,c,1} - \sum C_{el,c,2} \quad (5.2)$$

where $\sum C_{el,c,1}$ is the customers' summarised cost for electricity purchase before they have introduced end-use measures. $\sum C_{el,c,2}$ is the customers' summarised cost for electricity purchase after they have introduced end-use measures.

The profitability for introducing end-use measures, from the distributor's point of view, depends on the relation between $\Delta C_{el,d}$ and ΔR_d . If $\Delta C_{el,d} > \Delta R_d$, end-use measures will be profitable for the distributor. On the other hand, if $\Delta C_{el,d} < \Delta R_d$, end-use measures will *not* be profitable for the distributor.

Also the power producer will be affected by the introduction of end-use measures. However, the effect will be quite small when there is no cooperation between distributor and customer. The power producer will be much more affected if there is a cooperation between distributor and customers and/or a municipal cogeneration plant is introduced.

Different load levels. The influence of power-reducing end-use measures can be studied on different load levels in the system of distributor and customers. Such study will show how lack of cooperation will affect the system in different steps in the form of reduced peak loads.

A *first* load level is defined by the sum of power reduction potentials of identified end-use measures. The load level defines the maximal power-reduction capacity, and can serve as a reference value. A *second* load level shows the peak load reduction in the system of the customer. The reduction will depend on the total load characteristic of the customer and the operating time of the device that is subjected to the end-use measure.

A *third* load level shows the peak load reduction in the system representing the group of customers that have introduced end-use measures. The reduction will depend on load characteristics and end-use measures in several customer systems. A *fourth* load level shows the peak load reduction in the system of distributor and customers, i. e. the local market. The reduction will depend on load characteristics of all the customer categories, with and without end-use measures, that exist in the local market.

A *fifth* load level can be defined which is associated with the way the power cost of the power producer is calculated. Power reductions on different load levels have been presented by Andersson (1993) and in *Paper I*. The results

are summarised in Table 5.1. (For load level 2 in Table 5.1 the figure represents the sum of peak load reductions in individual customer systems.)

Table 5.1. Power reductions for different load levels.

<i>Load level</i>	<i>Power reduction (kW)</i>
1	3300
2	1900
3	1500
4	1100
5	100

The power reduction on the fifth load level has been calculated for a case where the end-use measures were used to reduce the peak load of the year. Since the average value for the power charge is based on three power values from the five different winter months the total power reduction, or average value, is quite small. To obtain a larger cost reduction end-use measures should be used not only to reduce the peak load of the year, but also the peak loads of the separate winter months.

5.2 Cooperation

For analysing consequences of cooperation between distributor and customers some procedures for system analysis have been developed. When distributor and customers cooperate, they are regarded as one actor, or system, see Fig. 5.2. When cooperation exists, information of load profile and electricity costs of the common system S_{tot} is assumed to be known. Customers who are suitable for participating in cooperation are not necessarily large electricity users. Instead they have loads that by end-use measures can affect the load profile of S_{tot} in a profitable way. In other words, S_{tot} can reduce peak loads by introducing suitable end-use measures in selected customer systems S_{sub} .

Figure 5.2. Cooperation between distributor and customer.

For S_{tot} it is profitable to reduce electricity demand at times there are peak loads in S_{tot} , and not necessarily when there are peak loads in S_{sub} . When S_{tot} has peak loads the electricity cost of the distributor is much larger than the price customers pay to the distributor for the corresponding time period. This relation between costs are illustrated schematically in Fig. 5.3.

Figure 5.3. Cost relation between distributor and customer.

As a result of the cooperation the distributor will reduce costs for electricity purchase much more. If the peak loads of S_{tot} and S_{sub} do not coincide in time, customers will not reduce their own costs for power and subscription, despite

power-reducing end-use measures. End-use measures can also imply energy reduction over a longer time period. Since the energy price of the distributor is higher than the energy price of the power producer, ΔR_d corresponding to reductions in energy costs will be larger than $\Delta C_{el,d}$. However profitability will be obtained for both parts if the end-use measures can reduce or postpone investments on the supply-side in S_{tot} .

Figure 5.4. Cost relation between electricity and fuel.

Bivalent heating will imply increased electricity selling if the heat load is originally based on fuel. Increased electricity selling is profitable during time periods when the relation between costs is as illustrated in Fig. 5.4. That is to say, the fuel cost is lower than the electricity cost of the customer, but higher than the electricity cost of the distributor. The electricity cost of the customer, for the end-use measure, should be on a level somewhere between the fuel cost and the distributor's electricity cost.

5.2.1 Cost reduction - *MODEST*

One way of calculating $\Delta C_{(b)system,d}$ for a certain amount of end-use measures is to run *MODEST* first for $L_{d,1}$ and then for $L_{d,2}$. The difference in the value of the objective function of, for instance, one year is $\Delta C_{(1)system,d}$, see Eq. (5.3). $\Delta C_{(1)system,d}$ will be maximised since it is assumed that all power values

which are the basis of the power producer's power and subscription charges will be reduced by the maximal power reduction capacity of the end-use measures.

In some local markets both end-use measures and municipal cogeneration plants will be cost-effective. By using this procedure it can be found that with end-use measures the optimal size of the new cogeneration plant is reduced.

$$\Delta C_{(1)system,d} = C^T x_1 - C^T x_2 \quad (5.3)$$

5.2.2 Cooperation - power cost

The purpose is to calculate the cost of S_{tot} for supplying electricity to S_{sub} when the distributor and customer are regarded as one system. This is a reference cost that can be used for estimating the profitability for system measures. The calculation can be divided into two parts: calculation of the power cost of S_{sub} for peak load periods in S_{tot} and calculation of the energy cost of S_{sub} for the rest of the year.

To calculate the power cost $C_{(1)power,d}$ the peak loads in S_{tot} are first identified. If the length of the time period representing peak loads $t_i = 5$ h, $C_{(1)power,d}$ is calculated according to the following equations (Y_i for the peak load period in S_{tot} is derived using *MODEST*.):

$$Y_i = [(1000 \cdot c_{power}) / 5] + c_{energy,i} + c_{el,tax} \quad (5.4)$$

$$C_{(1)power,d} = Y_i \cdot \sum_{i=1}^5 P_c \quad (5.5)$$

where c_{power} is the sum of the power and subscription charges, $c_{energy,i}$ is the energy price for the prevailing time period, $c_{el,tax}$ is the electricity tax and P_c represents one-hour power values in the customer system during the peak load period in S_{tot} .

The cost of S_{tot} for supplying S_{sub} with electricity for the rest of the year is obtained by simulating the energy use of S_{sub} with *STRATO* and with the prices for electricity purchase to S_{tot} as input data.

5.2.3 Cost reduction - shadow price

The profitability for cooperation and end-use measures can also be estimated via Y_i for electricity demand, Eq. (5.4). Y_i will make clear the

incentives per, for instance, megawatt hour for introducing end-use measures. $\Delta C_{(1)system,d}$ is calculated according to Eq. (5.6) where $P_{max,red}$ is the total maximal power reduction capacity of the identified end-use measures.

$$\Delta C_{(1)system,d} = Y_i \cdot t_i \cdot P_{max,red} \quad (5.6)$$

The analysis procedure of cooperation and introduction of end-use measures is presented in Fig. 5.5.

5.2.4 Cost reduction - load priority system

A procedure for calculating $\Delta C_{(1)system,d}$ for a load priority system designed for minimising the costs for S_{tot} has been worked out. The procedure considers *five* power limits $P_{limit,month}$ for the five winter months, and a time division where power data are specified hour by hour. (In *STRATO* there is *one* power limit for all months.) When the demand for electricity in S_{tot} exceeds $P_{limit,month}$, loads are disconnected, but only to the extent so that the P will be equal to $P_{limit,month}$. All loads are disconnected at the same time *solely* during that hour when the demand equals the peak load.

As a result of the way the power cost is traditionally calculated the power-reducing end-use measures should be used during each winter month, even if the peak load of the month is relatively small compared to the peak load of the year. $P_{limit,month}$ is calculated as follows:

$$P_{limit,month} = P_{peak,month} - P_{max,red} \quad (5.7)$$

where $P_{peak,month}$ is the peak load of the specific month. If $P_{limit,month}$ implies that the load priority system must be used a relatively long time period it can be replaced by another power limit $P_{limit,month}^*$ which corresponds to a smaller power reduction. $P_{limit,month}^*$ is calculated as follows:

$$P_{limit,month}^* = P_{peak,month} - P_{adj}, \quad (5.8)$$

where P_{adj} corresponds to a power reduction that is less than $P_{max,red}$. The total cost reduction which is a result of the load priority system of the local market is calculated according to the following equations:

$$\Delta C_{(1)power,d} = (P_{x,1} - P_{x,2}) c_{peak} + (P_{sub,1} - P_{sub,2}) c_{sub} \quad (5.9)$$

Figure 5.5. The calculation procedure for cooperation.

$$\Delta C_{(1)energy,d} = \sum_i (P_i - P_{limit,month}) c_{energy,i} \quad (5.10)$$

and consequently

$$\Delta C_{(1)system,d} = \Delta C_{(1)power,d} + \Delta C_{(1)energy,d} \quad (5.11)$$

where $P_{x,1}$ in Eq. (5.9) is the average value of x power values before end-use measures are introduced and $P_{x,2}$ is the new average value after end-use measures are introduced. The power charge is represented by c_{peak} . $P_{sub,1}$ is the subscribed power level before end-use measures are introduced and $P_{sub,2}$ is the new power level after end-use measures are introduced. The subscription charge is represented by c_{sub} . In Eq. (5.10) P_i represents one-hour power values which are larger than $P_{limit,month}$.

If local electricity generation is added to the load priority system, $\Delta C_{(1)system,d}$ should also include a term representing the additional cost for electricity generation in the customer system, $\Delta C_{el,c}$, as follows:

$$\Delta C_{(1)system,d} = \Delta C_{(1)power,d} + \Delta C_{(1)energy,d} - \Delta C_{el,c} \quad (5.12)$$

6 End-use measures and energy and grid tariffs

Introduction. In this system analysis the profitability for end-use measures designed for the local market will be studied. The analysis is a continuation of the system analysis presented in *Paper V*. The main difference between the two analyses is the tariff for electricity purchase to the local market. In *Paper V* the tariff is the high voltage tariff where prices and charges for energy supply and regional grid are included in the same tariff. In this chapter there is, as a result of the deregulated market, one tariff for energy supply and one for regional grid.

The system is a municipal system situated about 150 km north of Stockholm. 1994 the electrical energy use amounted to 780 GWh and the maximal power demand was 135 MW.

The measurement data show that the peak loads of the distributor and customer systems occurred in different days and at different hours of the day, see Tables 3.5 and 3.6. Consequently, if end-use measures are introduced the distributor and the customers must cooperate in order to avoid a suboptimisation within the local market. Hence, prices and charges for electricity purchase to the *local market* will serve as boundary conditions to the calculations of the profitability for end-use measures.

Eleven customers participated in the project. They are various industries, a hospital, an ice-hockey arena, a harbour, a water-works, a warehouse and a radio tower.

Energy tariff of the power producer. I have been able to study a general energy tariff, called trade tariff, valid for contracts between this power producer and large customers, like distributors. Unfortunately, this tariff can not be described in detail since it is classified as strictly secret.

At the starting-point the tariff consists of four cost elements: energy price, subscription charge, power charge and fixed charge. As in the previous high voltage tariff the *power charge* is based on the average value of fifteen one-hour power values. The power values represent the three largest power values of the winter months, from different days, Monday to Friday, between 6 a. m. and 10 p. m. The *subscription charge* is based on a power value which is decided in advance. The energy prices have the same time differentiation as shown in Table 3.7.

The level of prices and charges of the energy tariff differs from the level of prices and charges of the high voltage tariff. One reason for this is that charges and prices that covered electricity transmission in the high voltage tariff now are represented in the grid tariff.

In spite of the fact that the final agreement between the power producer and the distributor is not known, calculations have been performed with the trade tariff as input data. The aim is to study the trend for profitability of end-use measures with the energy and grid tariffs as boundary conditions. In the energy and grid tariffs the power charge is reduced, compared to the high voltage tariff, while the total subscription charge is increased.

Regional grid tariff. Also the grid tariff consists of energy price, subscription charge, power charge and fixed charge (Vattenfall, 1995). The energy price covers costs of energy losses on the regional and national grids.

The time differentiation constitutes of two periods. During winter daytime, Monday to Friday, 6 a. m. to 10 p. m., the price is about 15 SEK/MWh. During the remaining part of the year the price is about 5 SEK/MWh.

The *subscription charge*, and part of the *fixed charge*, cover capacity costs for electricity transmission to a specific customer. The subscription charge is based on the average value of the two largest one-hour power values of the year. The *power charge* covers capacity costs for transmission to several customers. It also covers costs for connections to other grids. The power charge is based on the two largest one-hour power values of the five winter months, Monday to Friday, 6 a. m. to 10 p. m. In most cases the largest power demands will occur in the winter and hence the power charge and the subscription charge will be based on the same average value. The sum of the power and subscription charges is about 100 SEK/kW.

In Fig. 6.1 the distribution of power and subscription charges in the tariffs that have been studied is described. (Since the tariffs are strictly secret the charges can not be described in detail.) The power charge in the grid tariff can be seen as a subscription charge since the way the power cost is calculated is similar to the way the subscription cost is calculated. As can be seen, the total charge for power and subscription is reduced with the energy and grid tariffs, but the share of subscription charges is increased. The power charge in the energy tariff is reduced by about 60 % compared to the high voltage tariff, while the total subscription charge is increased by about 150 %.

Figure 6.1. The sum of power and subscription charges. The charge up to the line represents subscription charges.

Results. For the eleven customer systems $P_{max,red} = 8\,642$ kW. The end-use measures for the local market are load priority system, time rescheduling of separate processes and local electricity generation in reserve power plants. The calculations have been carried out, as in *Paper V*, according to two analysis procedures, i. e. the analysis for maximal cost reduction (1), see *Chapters 5.2.2-3*, and the analysis for cost reduction based on one-hour power values of a certain year (2), see *Chapter 5.2.4*. Prices and charges for electricity purchase to the local market is the sum of the corresponding cost elements in the energy and grid tariffs.

(1) The shadow price Y_i , or marginal cost, representing the five peak load hours of the year is calculated according to Eq. (5.4). For the energy and grid tariffs $Y_i = 51\,000$ SEK/MWh. This is a reduction of about 23 % compared to Y_i representing the high voltage tariff. The cost reduction of the system $\Delta C_{(1)system,d}$ is calculated according to Eq. (5.6) and represents the maximal cost reduction for the identified end-use measures. With the energy and grid tariffs as input data $\Delta C_{(1)system,d} = 2.20$ million SEK for one year. This is approximately 1 % of the total cost for electricity purchase from the power producer.

(2) When the calculation is based on one-hour power values, the cost reduction is calculated according to Eqs. (5.7) to (5.12). In this case $\Delta C_{(1)system,d} = 1.89$ million SEK. The shape of the load curves show peak loads that are not as clear and distinct as assumed in (1). Consequently, $P_{max,red}$ can not be used and $\Delta C_{(1)system,d}$ will obtain a lower value than in (1). The number of hours that the end-use measures are used during each winter month is equal as in *Paper V*.

The difference between the maximal cost reduction and the cost reduction for 1994 is decreased compared to the results from the high voltage tariff, see Table 6.1 and *Paper V*. The reason why the difference is reduced is that the share of total subscription charge is increased in the energy and grid tariffs while the share of power charge is decreased.

The subscription charge is based on one or two power values while the power charge is based on fifteen power values from different months. Hence, the probability for reaching a maximal cost reduction for a certain amount of end-use measures should increase with this energy and grid tariffs, and with a load profile similar to that of 1994. The load profile of January for 1994, which includes the largest power demand of the year, is characterised by a peak load that is clear and distinct. That peak load is also larger than the prevailing $P_{max,red}$. Therefore $P_{max,red}$ can be used to reduce the subscribed power. The cost reduction associated with the power charge will not be maximal since the peak loads of the different winter months are not clear and distinct enough in comparison with $P_{max,red}$.

Results - without power charge. To study the influence of the power charge on $\Delta C_{(1)system,d}$ a calculation has been performed where the power charge is excluded. That is, if there is no power charge in the agreement with the power producer, what will the cost reductions be?

Without the power charge Y_i will be reduced by 40 %. For (1) $\Delta C_{(1)system,d} = 1.33$ million SEK. For (2) $\Delta C_{(1)system,d} = 1.34$ million SEK. As can be seen, the latter cost reduction is larger than the former, the so-called optimal cost reduction. This is due to the fact that when analysis procedure (2) is used there is a somewhat larger reduction of energy use as a result of less clear and distinct peak loads.

In (2) the end-use measures are used 23 hours during the year (21 hours in January and 2 hours in March). The energy reduction amounts to 77 MWh. The energy reduction calculated with the time division of *MODEST* as a basis (i. e. analysis procedure (1)) is 43 MWh. In this case maximal cost reduction is achieved also for (2) because of the shape of the load curves and no power charge.

The results discussed in this chapter and in *Paper V* are summarised in Table 6.1.

Conclusions. The cost reduction for power-reducing end-use measures will be less with the energy and grid tariffs used here than with the high voltage tariff. However, the probability for achieving the maximal cost reduction for a certain

amount of end-use measures will increase, as the total subscription charge is increased. On the other hand, the incentive for reducing peak loads for separate winter month will be reduced, since the power charge is reduced.

Table 6.1. Cost reductions for different tariffs and calculation procedures.

<i>Tariff</i>	<i>Maximal cost reduction (MSEK/year)</i>	<i>Cost reduction based on one-hour power values (MSEK/year)</i>
High voltage tariff	2.85	1.91
Energy and grid tariffs	2.20	1.89
Only subscription charges ¹	1.33	1.34

In a spot-pricing market the price for electricity varies continuously, unlike the prices in the tariffs discussed here. Spot pricing implies that the price for buying and selling electricity is determined by the supply and demand conditions that are prevailing at the time. If the local market will purchase electricity in a spot-pricing market the profitability for using measures such as load priority systems, rescheduling, bivalent heating systems, energy storage and local electricity generation will increase as a result of the varying price. By having access to end-use measures when purchasing electricity in a spot-pricing market the probability for sudden increases in electricity costs for short time periods is decreased. End-use measures can be used as an insurance for sudden large costs and consequently the local market can take larger risks when purchasing electricity.

¹ Here, the power charge is excluded in the energy tariff.

7 Concluding remarks and future outlook

Cooperation. In energy systems which can be characterised as time-dependent and dynamic, cooperation will enable identification of cost-effective system measures. A system is time-dependent because of variations in energy demand and electricity prices over time. A system is dynamic if the energy demand in one time period also depends on conditions that exist in other time periods. By utilising variations in marginal costs and energy demand when introducing system measures such as end-use measures and cogeneration plants, the system cost will be minimised.

After the deregulation of the Swedish electricity market the buyer of electricity can choose seller. Buyer and seller will not in all cases be located close to each other, but this should not decrease the interest for cooperation and system measures. The advantages of even load profiles, lower electricity costs and increased competitiveness will exist also when distributor and customer are located far from each other.

Measures. End-use measures and cogeneration plants have partly different tasks in the system of the local market. With a cogeneration plant the local market will become a power producer itself and electricity purchase from power producers can be reduced. The cogeneration plant will first of all supply a base load, especially during the winter months, but it will also reduce peak loads. The size of a cogeneration plant is decided by prevailing conditions in the district-heating system, electricity prices and charges and also investment costs.

A cogeneration plant will often yield a greater system cost reduction than end-use measures will yield. On the other hand, end-use measures require lower investment costs and shorter pay-back periods. End-use measures, and above all load management measures, will increase the flexibility of the system as the system can better adjust to changes in energy prices, for instance in a spot-pricing market. The power reduction capacity of end-use measures is decided by what measures that can be found within a certain system, and consequently what customer categories that exist. Different customer categories have different prerequisites for controlling and changing the electric load. Engineering industries have often loads such as furnaces, galvanising pans, industrial washing machines, car-engine preheaters and also electricity-based heating of premises

and hot-water supply. These loads are suitable for load-management measures, energy conversion and/or energy efficiency. Hospitals have reserve power plants. Waterworks can time reschedule the use of pumps, if there is storage capacity left in the water towers.

Profitability in the national system. End-use measures and cogeneration plants constitute resources for the local market where they have been introduced. In the national system end-use measures can serve as system resources, or reserve capacities, during very cold winter days. By means of end-use measures selected loads can contribute to keep the national system cost on a relatively low level.

End-use measures and cogeneration plants can be of special interest in a long time perspective. They can reduce or postpone the need for new power generation capacity. They can also release generation capacity which can be used for export to, for instance, Germany.

The transmission business is a monopoly market and the grid owner does not have to compete for the customers. However, end-use measures should be advantageous also for the grid as they can reduce fluctuations in electricity demand. End-use measures can be used to replace or reduce the need for investments in the grid.

Consequently, in the short and long time perspective system measures can serve as system resources, or reserve capacities, also for power producers and grid owners.

Summary. Cooperation, end-use measures and cogeneration plants will make possible for local markets to strengthen their position in the national as well as international market.

In a market characterised by competition it will be necessary to improve the systems, i. e. increase the cost-efficiency. Improvement can be achieved by introducing end-use measures. With end-use measures the systems will obtain flexibility as well as reserve capacity and buyers will be able to take larger risks in electricity purchase, for instance in spot-pricing markets. Besides, it is also possible that power producers will compete for customers who, by means of end-use measures, have obtained advantageous load profiles. Improvement can also be achieved by introducing cogeneration plants based on biomass. If there is a CO_2 -tax for electricity generation introduced, electricity generation in biomass-fired cogeneration plants will not be affected and the system cost will be kept on a relatively low level.

In a deregulated market there will probably be a more careful weighing between investments on the supply- and demand-sides within the national

system. It is not a matter of course to invest in new power plants and then increase the prices in order to finance the investments. With a higher price the seller will lose customers if other sellers can offer lower prices.

Even though this work is focused on Swedish conditions, the general principles here presented should be easy to adapt to markets outside Sweden as well, especially to markets which are characterised as mainly power dimensioned and hence have a need to avoid power shortage. Such markets exist for instance in Germany and Denmark.

Future outlook. Boundary conditions to the market will change continuously, and new important actors will arise. A new actor can be defined by an enterprise, consisting of a group of companies, which has one electricity agreement representing all the companies. System analyses will show how different configurations of cooperation will affect, for instance, local markets. Furthermore, it is also of interest to see if and how grid owners will be affected by the formation of new actors. It is important to supervise the course of events in the deregulated market and to identify new case-studies which can contribute to an increased knowledge about conditions and possibilities that exist for the actors.

It is also of interest to analyse the conditions for cooperation and end-use measures in an *international* electricity market, including the Nordic countries, the Baltic States and the northern countries on the Continent, see Fig. 7.1. New conditions and possibilities will arise when more countries deregulate their electricity markets. In that case more customers will be able to purchase electricity from electricity suppliers in other countries. (Within the European Union there exists a plan for gradually deregulating the electricity markets.)

If the transmission capacity between Sweden and Germany is extended, the characteristics of the German system will affect the Swedish system. The German system is characterised as power dimensioned and the electricity demand varies above all between days and nights. Electricity trade with Germany will most certainly imply electricity export during daytime. During nights there is no need for Swedish power since there is capacity left in German power plants as a result of reduced electricity demand from German industries. If the electricity trade with Germany is increased, the difference in electricity demand between days and nights will probably increase in Sweden. If Sweden so to say import characteristics of the German system by trading with Germany, the profitability for end-use measures that can move the demand for energy and power between days and nights will most certainly increase in the Swedish system.

Figure 7.1. Cooperation between a Swedish distributor and its customers in an international electricity market. (It is also possible that the local market will purchase electricity directly from a foreign power producers and not via a Swedish power producer.)

What marginal costs for electricity will arise for Swedish customers as a result of increased electricity trade? The level of the marginal costs as well as their variation with time will give indication on what end-use measures that are profitable in the view of an international market. It is therefore of interest to analyse for Swedish industries what measures that are the most profitable ones with European boundary conditions, i. e. with electricity prices on a level with German prices. It would also be of interest to see how the customers in the other countries would be affected by an increased electricity trade. Will their marginal costs change and will end-use measures be profitable in their systems as well? In that case, what types of end-use measure should be introduced to minimise their system costs?

Today Swedish electricity prices are low compared with electricity prices in the world around, see Table 2.3. Consequently, in Sweden electricity is used to a relatively large extent compared with fuels. If the Swedish prices will increase, for instance as a result of increased trade with Germany, the relation between electricity and fuel use will presumably change, i. e. the use of electricity will decrease and the use of fuels will increase. In such case end-use

measures which imply energy conversion from electricity to fuel will become important together with end-use measures that reduce peak loads and electricity demand in general.

Also Swedish cogeneration plants, based on biomass, will presumably become of great importance for the Swedish system in an international market. In Sweden there is a simultaneous demand for electricity and district heating. District-heating systems already exist in several Swedish local markets. Besides, in Sweden there are major forest areas who can contribute with fuel for cogeneration. The profitability for biomass-fired cogeneration plants will increase even more if a CO_2 -charge for electricity generation is introduced. (Within the European Union there has been discussions about the introduction a CO_2 -charge.) In that case it will be profitable to replace some of the electricity generated with fossil fuels, in e. g. Germany and Denmark, by electricity generated with biomass in Sweden.

The purpose of this thesis is to develop an analysis procedure and to apply it to a number of case-studies to point at the necessity of cooperation and measures within local markets. The suggestions for future works that have been mentioned in this chapter deals with new boundary conditions that may arise. However, the next step after system analyses is to realise suggested measures. Therefore, procedures ought to be developed which can help building a 'bridge' between calculations with system models and realisation of suggested measures. There is also a need for developing equipment for operation control that can help realising cooperation and end-use measures in practice. It can also be of interest to study other aspects of cooperation than those discussed in this thesis. For instance, will energy system measures and cooperation affect employment and environment?

8 Comments on enclosed papers

In this chapter I will shortly comment on things that differ between the papers and things that are common. Summaries of results are presented in the abstracts of the individual papers and in *Chapter 1.3* and will not be mentioned here.

In the following five papers three different local markets have been analysed concerning cooperation, end-use measures, cogeneration plants and shadow prices. As discussed in *Chapters 4* and *5* simulation and calculation procedures have been further developed. Also the optimisation model *MODEST* has been further developed through the years. *MODEST* was first constructed by Backlund (1988). Henning (1994) has introduced various procedures for system description and data handling. Hence with the new version of *MODEST* complex systems can easily be described. The new version has also been to a great help when studying shadow prices and sensitivity of the optimal solution. Table 8.1 shows what version of optimisation and simulation models that has been applied in *Papers I - V*.

Table 8.1. Optimisation and simulation models

<i>Paper No.</i>	<i>MODEST by Backlund</i>	<i>MODEST by Henning</i>	<i>INDSIM</i>	<i>STRATO</i>
<i>Paper I</i>	X			X
<i>Paper II</i>	X			X
<i>Paper III</i>		X		
<i>Paper IV</i>		X	X	
<i>Paper V</i>		X	X	

Paper I: Cost-effective energy system measures studied by dynamic modelling. For simulating the effect of end-use measures, introduced without cooperation, *STRATO* has been applied. The customer systems are simulated for a time period of 25 years and with annual price increases. Lack of cooperation is simulated according to *Chapter 5.1*.

The influence of end-use measures introduced in cooperation has been analysed by running *MODEST*, first with the original load profile and then with

the changed load profile reflecting different end-use measures (*Chapter 5.2.1*). The end-use measures include load management, local electricity generation, efficiency improvement and energy conversion.

In the calculations investment costs for all measures have been considered. Furthermore, all costs are presented in GBP (Great British Pound) as the paper was presented on an international conference. At the time the paper was written 1 GBP was approximately 10 SEK.

Paper II: Energy system cost reduction as a result of end-use measures and the introduction of a biomass-fired cogeneration plant.

Paper II is based on the same system and calculations as in *Paper I* but is instead focused on the difference in fuel mix between the original and optimised systems. As in *Paper I* costs are presented in GBP.

A few numbers, describing results of the introduction of end-use measures, have been corrected.

Paper III: Shadow prices for heat generation in time-dependent and dynamic energy systems.

In this paper shadow prices for district-heating generation have been analysed. The paper is focused on the influence of energy storage on the shadow price for district-heating demand.

The price of district-heating is for instance in Linköping 285 SEK/MWh for the whole year (Tekniska Verken i Linköping, 1996). That is to say, there is no time-differentiation.

In this paper a sensitivity analysis of the shadow prices is presented as well. The sensitivity analysis shows in what intervals of the district-heating demand the shadow prices can be used for predicting changes in the discounted system cost.

Paper IV: Cost-effective incentives for cooperation between participants in the electricity market.

In *Paper IV* cooperation has been simulated using the procedure described in *Chapter 5.2.2*. One peak-load hour per winter month serves as a basis for the calculation. It is assumed that the peak-load hours in the distributor system occur on the first workday in each of the five winter months, between 7 a. m. and 8 a. m. The electricity demand of the customers during these hours are identified in the data file consisting of the constructed load profile of one year.

The cost reduction is calculated by using the shadow prices of the distributor system as described in *Chapter 5.2.3*.

In Table 5 (*Paper IV*) S_{Δ} representing the nursery garden should instead be 1 289 000 SEK.

Paper V: Cost-effective incentives for end-use measures in a Swedish municipality.

In *Paper V* fifteen peak-load hours serve as a basis for the simulation of cooperation (*Chapter 5.2.2*), i. e. three peak-load hours from each winter month. The times for peak loads in the distributor system have been estimated by studying the load curve of 1994. It is assumed that the first peak-load hour for each month occur at 10 a. m., the second at 5 p. m. and the third at 6 p. m. For simplicity it is assumed that the first five working days in the constructed load curves of the customers represent the five peak load days of the five winter months. In this paper the calculation should better reflect the real situation since more peak-load hours are considered.

The cost reduction is calculated using the shadow prices of the distributor system (*Chapter 5.2.3*). In addition, the influence of end-use measures on the load profile of 1994 is calculated (*Chapter 5.2.4*).

Sensitivity analysis. Sensitivity analysis of shadow prices for electricity demand has not been described so far in this thesis. However, sensitivity analyses in connection with optimisation of local markets have shown that the solutions are relatively stable. In the case-studies the prices and charges for electricity purchase define the shadow prices for almost all time periods. The solution is stable since the possibility to purchase more electricity is practically unlimited. However, there is at least one situation when the solution can become less stable. This constitutes of a situation where a small increase in power demand will cause a new peak load. The cost for power and subscription will then be removed from one time period to another. If the new peak load period consists of a larger number of hours, the new shadow price will be lower since the total cost will be divided on a larger number of hours. If the new time period is shorter, the new shadow price will consequently be larger.

If the distributor completes with electricity generation in a cogeneration plant there is, in most cases, no change of the stability of the shadow prices for electricity. The operation of the cogeneration plant is first of all managed by the prevailing conditions in the district-heating system.

9 List of symbols

For some symbols and subscripts there is a parenthesis showing a Roman figure. The Roman figure tells that the symbol or subscript has been used in the paper that is represented by the figure.

A	information matrix about the represented system	(W)
AC	average cost	(SEK/MWh)
B	vector representing demand and capacity	(W)
b	length of analysis period	(year)
C, c	cost	(SEK)
CC	capacity cost	(SEK)
C_{energy}	discounted energy costs	(SEK)
C_{fix}	discounted fixed costs	(SEK)
C_{inv}	discounted investment costs	(SEK)
C_{inv}^*	discounted investment costs for a second investment	(SEK)
C_{power}	discounted power costs	(SEK)
CHP	combined heat and power, cogeneration	
CS	customers' surplus	(SEK)
C_{system}	discounted system cost	(SEK)
C^T	cost vector	(SEK/MWh, SEK/MW)
$c_{el,tax}$	electricity tax	(SEK/MWh)
c_{energy}	energy price	(SEK/MWh)
c_{peak}	power charge	(SEK/MW)
c_{power}	sum of power and subscription charges	(SEK/MW)
c_{sub}	subscription charge	(SEK/MW)
D	demand	(MW)
DSM	demand-side management	
E	useful heat output / energy (II, III, IV)	(W, Wh)
E_d	price elasticity	
I	investment cost	(SEK, SEK/MW)
j	annual price increase	(%)
L	load profile	(W)
LP	linear programming	

$LRMC$	long range marginal cost	(SEK/MWh)
l	economic life	(year)
MC	marginal cost	(SEK/MWh)
m	maximal capacity of existing plant	(W)
$NP_{r,n}$	net present factor	
$NPS_{r,b,j}$	net present sum including price increase	
n	specific year during the analysis period	
P	power value, demand	(W)
P_{adj}	adjusted power reduction	(W)
P_x	average value of x power values	(W)
P_{in}	input power	(W)
P_{limit}	power limit	(W)
P_{limit}^*	adjuster power limit	(W)
$P_{max,red}$	summarised power reduction from end-use measures	(W)
P_{out}	output power	(W)
P_{max}	maximal demand for a certain shadow price (III)	(W)
P_{min}	minimal demand for a certain shadow price (III)	(W)
P_{peak}	largest power value, or values, of the year	(W)
P_{plant}	needed capacity from an existing plant	(W)
P_{rec}	largest power value among recorded data	(W)
PS	producers' surplus	(SEK)
P_{size}	power capacity of a new plant	(W)
P_{sub}	power value for subscription	(W)
p	price, cost	(SEK/MWh)
$P_{heat\ pump}$	additional cost for using a municipal heat pump	(SEK/MWh)
Q_{in}	power input, energy input (II)	(MW, MWh)
Q_{net}	energy needed on the grid or district-heating network	(MWh)
q	quantity, energy demand	(MWh)
R	revenue	(SEK)
$Rand$	random factor between 0 and 1	
RC	running cost	(SEK)
RF	factor used when creating an annual load curve	
r	interest rate	(%)
S	annual system cost (IV)	(SEK)
TOU	time of use	
TPA	third party access	
Y	shadow price / power vector (I, II)	(SEK/MWh, MW)
$SRMC$	short range marginal cost	(SEK/MWh)
S_{sub}	subsystem within a local market (i. e. a customer system)	

S_{tot}	local market including distributor and customers	
t	length of time step	(h)
W	total surplus / power output (II)	(SEK, MW)
X	power variable (I, II)	(W)
x	power or capacity value	(W)
x_o	system cost (IV)	(SEK)

Greek symbols

α	cogeneration ratio
Δ	change in cost, price or revenue
ϕ	coefficient of performance for heat pump
η	efficiency
η_E	useful heat efficiency (II)
η_p	efficiency of a heating plant (III)
η_s	efficiency of an energy storage (III)
η_{tot}	total efficiency of a cogeneration plant (II)
η_{trans}	energy loss associated with energy transmission
η_w	power efficiency (II)

Subscripts

I	original system
2	system including measures
c	customer
d	distributor
el	electricity
h	useful heat
i	time period / time period for charge (III)
j	time period for discharge (III)
max	maximal
$month$	specific month of the year
oil	oil (IV)
Δ	change in cost (IV)

10 References

Andersson, G., *Calculations as decision support*, ISBN: 91-44-43502-9, Studentlitteratur, Lund, 1984. (*In Swedish*)

Andersson, M., Björk, C. and Karlsson, B., A model for industrial load management optimisation and its application on an industry and a municipality, *Canadian Electrical Association's Demand-Side Management Conference*, October 22-24, Toronto, Canada, pp. 161-171, 1990.

Andersson, M., Björk, C. and Karlsson, B., Cooperation results in reduced energy system costs, *Energi & Miljö*, Vol. 62., No. 12, pp. 36-39, 1991. (*In Swedish*)

Andersson, M., Backlund, L., Björk, C. and Karlsson, B., Short range marginal costs in the Swedish electric energy system, *Conference on Metering Apparatus and Tariffs for Electricity Supply*, Institution of Electrical Engineers (IEE), November 17-19, Glasgow, UK, pp. 5-8, 1992.

Andersson, M., Cost-effective incentives for local electric utilities and industries in cooperation - modelling of technical measures, LiTH, LIU-TEK-LIC-1993:12, Thesis No. 370, ISBN: 91-7871-103-7, ISSN: 0280-7971, 1993.

Backlund, L., Optimisation of dynamic energy systems with time dependent components and boundary conditions, LiTH, Dissertation No. 181, ISBN: 91-7870-336-0, ISSN: 0345-7524, 1988.

Björk, C., *Industrial load management - theory, practice and simulations*, ISBN: 0-444-87365-1, Elsevier Science Publisher B. V., The Netherlands, 1989.

Björk, C., Reduced electricity use in 50 industries in Lund, Eskilstuna and Skellefteå, LiTH-IKP-R-612, 1991. (*In Swedish*)

Björk, C., Söderström, M., Andersson, M. and Karlsson, B., Potential traps and possibilities in DSM marketing and implementation, *Utility Marketing 2000*, February 12-13, Orlando, Florida, pp. 189-210, 1991.

- Bohman, M., Optimal pricing of energy, *Seminar om Energiplanering i de Nordiske Lande*, Akureyri, Island, 19-22 augusti, pp. 191-198, 1991. (In Swedish)
- Bohn R. E., Caramanis M. C. and Schweppe F. C., Optimal pricing in electrical networks over space and time, *Rand Journal of Economics*, Vol. 15, No. 3, pp. 360-376, 1984.
- Busch, J. and Eto, J., Estimation of avoided costs for electric utility demand-side planning, *Energy Sources*, Vol. 18, pp. 473-499, 1996.
- Caramanis M. C., Bohn R. E. and Schweppe F. C., Optimal spot pricing, practice and theory, *IEEE*, Vol. 101, No. 9, pp. 1-12, 1982.
- Caramanis M. C., Investment decisions and long-term planning under electricity spot pricing, *IEEE*, Vol. 101, No. 12, pp. 1-9, 1982.
- Carlsson, A., Energy supply in local utilities - a study of energy systems when external effects are included, *International Symposium on Economic Modelling*, 3 - 5 July, Oslo, Norway, 1996.
- Christiansson, L., Time dynamics of electricity demand in air-distribution systems for commercial buildings in Sweden, *Energy*, Vol. 21, No. 10, pp. 879-888, 1996.
- Dag, S. and Björk, C., A model for cost-effective cooperation between a municipal energy system and an industry, *International Symposium on Economic Modelling*, 3 - 5 July, Oslo, Norway, 1996.
- David, A. K. and Li, Y. Z., A comparison of system response for different types of real time pricing, *Conference on Advances in Power System Control and Management*, IEE, Hong Kong, pp. 385-390, 1991^a.
- David, A. K. and Li, Y. Z., Electricity pricing with competitive supply conditions, *Electrical Power & Energy Systems*, Vol. 13, No. 2, pp. 111-122, 1991^b.

David, A. K. and Li, Y. Z., Consumer rationality assumptions in the real-time pricing of electricity, *Conference on Generation Transmission and Distribution*, IEE, Vol. 139, No. 4, pp. 315-322, 1992.

David, A. K. and Li, Y. Z., Effect of inter-temporal factors on the real time pricing of electricity, *IEEE Transactions on Power Systems*, Vol. 8, No. 1, pp. 44-52, 1993^a.

David, A. K. and Li, Y. Z., A rational approach for incorporating capital costs in the real-time pricing of electricity, *Electrical Power and Energy Systems*, Vol. 15, No. 3, pp. 179-184, 1993^b.

Foulds, L. R., *Optimization techniques - an introduction*, ISBN: 0-387-90586-3, Springer-Verlag New York Inc., 1981.

Haywood, R., *Analysis of engineering cycles*, 4th edition, ISBN: 0-08-040739-0, Pergamon Press, Oxford, UK, 1991.

Henning, D., Energy systems optimisation applied to local Swedish utilities, LiTH, LIU-TEC-LIC-1994:20, Thesis No. 434, ISBN: 91-7871-368-4, ISSN: 0280-7971, 1994.

Henning, D. and Karlsson, B., Simulation of the settlement of the nuclear power for Naturskyddsföreningen, LiTH-IKP-R-905, Linköping, 1996. (*In Swedish*)

Hjalmarsson, L. and Veiderpass, A., The Swedish electricity market - an overview over function and rules of the game, Nationalekonomiska institutionen, Handelshögskolan, Göteborgs universitet, 1986. (*In Swedish*)

Hollander, J. and Schneider, T., Energy efficiency, issues for the decade, *Energy*, Vol. 21, No. 4, pp. 273-287, 1996.

Hunt, S. and Shuttleworth, G., Electricity transmission pricing, the new approach, *Utilities Policy*, Vol. 3, No. 2, pp. 98-111, 1993.

James, D. E., Musgrove, A. R. and Stocks, K. J., Integration of an economic input-output model and a linear programming technological model for energy systems analysis, *Energy Economics*, April, pp. 99-112, 1986.

Karlsson, B., Söderström, M. and Henning, D., Simulation of the settlement of nuclear - at the request of the Energy Commission, LiTH-IKP-R-888, Linköping, 1995. (*In Swedish*)

Lo, K., McDonald, J. R. and Le, T. Q., Time-of-day electricity pricing incorporating elasticity for load management purposes, *Electrical Power & Energy Systems*, Vol. 13, No. 4, pp. 230-239, 1991.

Lamps user guide, Advanced Mathematical Software Ltd, UK, 1991.

Lipsey, R., Steiner, P., Purvis, D. and Courant, P., *Economics*, 9th edition, ISBN: 0-60-043908-4, Harper & Row, Publishers, Inc., New York, USA, 1990.

McDonald J. R., Whiting P. A. and Lo K. L., Spot-pricing - evaluation, simulation and modelling of dynamic tariff structures, *Electrical Power & Energy Systems*, Vol. 16, No. 1, pp. 23-34, 1994^a.

McDonald J. R., Whiting P. A. and Lo K. L., Optimized reaction on large electrical consumers in response to spot-price tariffs, *Electrical Power & Energy Systems*, Vol. 16, No. 1, pp. 35-48, 1994^b.

Nilsson, K., Cost-effective industrial energy systems, LiTH, Dissertation No. 315, ISBN: 91-7871-156-8, ISSN: 0345-7524, 1993.

Nilsson, K. and Söderström, M., Industrial application of production planning with optimal electricity demand, *Applied Energy*, Vol. 46, No. 2, pp 181-192, 1993.

NUTEK (Närings- och teknikutvecklingsverket), The electricity markets in Europe 1993, B 1993:13, ISBN: 91-7318-2656, ISSN: 1102-2566, Nutek Analys, Gotab, Stockholm, 1993. (*In Swedish*)

NUTEK (Närings- och teknikutvecklingsverket), Energiläget 1996, Alfa-Print AB, Sundbyberg, 1996. (*In Swedish*)

Outhred H. R., Bannister C. H., Kaye R. J., Lee Y. B., Sutano D. and Manimaran R., Electricity pricing for optimal operation and investment by industrial consumers, *IEE Energy Policy-Special Issue*, Spot Pricing in Non-oil Energy, 1988.

Parikh, J. K., Sudhakara Reddy, B., Rangan Banerjee and Koundiny, S., DSM survey in India, awareness, barriers and implementability, *Energy*, Vol. 21, No. 10, pp. 955-966, 1996.

Schrøder Amundsen E., Bjørndalen, J. and Rasmussen H., Export of Norwegian hydropower under a common European regime of environmental taxes, *Energy Economics*, Vol. 16, No. 4, pp. 271-280, 1994.

Sheen J. N., Chen C. S. and Yang J. K., Time-of-use pricing for load management programs in Taiwan power company, *IEEE Transactions on Power Systems*, Vol. 9, No. 1, pp. 388-395, 1994.

Sudhakara Reddy, B., Economic evaluation of demand-side management options using utility avoided costs, *Energy*, Vol. 21, No. 6, pp. 473-482, 1996.

Siddiqi, S. N. and Baughman, M. L., Reliability differentiated real-time pricing of electricity, *IEEE Transactions on Power Systems*, Vol. 8, No. 2, pp. 548-554, 1993.

SOU 1995:14, The new electricity market, ISBN: 91-38-13886-7, ISSN: 0375-250X, Norstedts Tryckeri AB, Stockholm, 1995. (*In Swedish*)

Sparrow, F. T. and Schmidt, P. S., Demand-side management implications of electrically-based manufacturing technologies, *Energy*, Vol. 18, No. 10, pp. 1067-1076, 1993.

Svenska Kraftverksföreningen, The power year of 1995, Karlerik Lindgren AB/Stellan Ståls Tryckerier, 1996. (*In Swedish*)

Tabors R. D., Transmission system management and pricing, new paradigms and international comparisons, *IEEE Transactions on Power Systems*, Vol. 9, No. 1, pp. 206-214, 1994.

Tekniska Verken i Linköping, Prices for households 1996, 1996. (*In Swedish*)

Vattenfall Regionnät AB, Grid tariffs 1996 for the south of Sweden, Abrahamsons Tryckeri AB, Karlskrona, 1995. (*In Swedish*)

Vine, E. L., International DSM and DSM program evaluation, an indeep assessment, *Energy*, Vol. 21, No. 10, pp. 983-996, 1996.

Wene, C.-O., Energy economy analysis, linking the macroeconomic and systems engineering approaches, *Energy*, Vol. 21, No. 9, pp. 809-824, 1996.

Williams, H. P., *Model building in mathematical programming*, John Wiley & Sons Ltd, Baffins Lane, Chichester, West Sussex, PO19 1UD, England, 1991.

Papers

The papers associated with this thesis have been removed for copyright reasons. For more details about these see:

<http://urn.kb.se/resolve?urn=urn:nbn:se:liu:diva-165083>