DISSERTATION

The relevance of demand-side-measures and elastic demand curves to increase market performance in liberalized electricity markets: The case of Austria

ausgeführt zum Zweck der Erlangung des akademischen Grades
eines Doktors der technischen Wissenschaften

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Hofamt Priel, im November 03 ……………….………………

Never fear big words
Big long words name little things
All big things have little names
Such as life, night, hope, love, home.
Learn to use little words in a big way
It is hard to do
But they say what you mean.
When you don't know what you mean –
Use big words
They often fool little people.

- Arthur Kudner to his son

Acknowledgments

This thesis is gratefully dedicated to my parents and grandmothers who always supported me.

At this point it is appropriate to say thank you to some persons who made this thesis possible.

Especially, I want to thank my supervisor and boss Dr. Reinhard Haas for his support on my way to this thesis. Thanks for the possibility to conduct my PhD and work in such an independent way.

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Hofamt Priel, November 03 Michael Stadler

Kurzfassung

Ein wesentliches Ziel der EU Direktive zur Liberalisierung der europäischen Elektrizitätsmärkte war es „niedrige“ Strompreise für die gesamte Wirtschaft zur Verfügung zu stellen. Wie sich aber zeigt, stiegen die Großhandelspreise seit dem Beginn Liberalisierung stetig an und es zeichnet sich auch ein weiterer, zum Teil starker, Anstieg der Preise für die Zukunft ab.
Aufgrund der Entflechtung der Erzeugung und Vertrieb vom Netz und der Implementierung des Wettbewerbs im Erzeugersegment, werden die Erzeugungs- und Vertriebsunternehmen verstärktem Druck seitens der Mitbewerber ausgesetzt. Das führt unter anderem dazu, dass die Unternehmen ihr Verhalten verändern, um sich am Markt behaupten zu können. Die elektrische Energie wird im zunehmenden Maße zu Grenzkosten der Erzeugung und nicht zu Durchschnittskosten verkauft. Es entstehen Großhandelsplätze (Spotmärkte), welche den Referenzpreis für elektrische Energie bestimmen. Es zeigt sich aber immer häufiger, dass diese Märkte volatiler – vor allem in den Wintermonaten – werden. Die Preise in den Starklastperioden steigen immer mehr an und die Differenz zwischen den Preisen in der Starklast- und Schwachlastperiode nimmt aufgrund fehlender Erzeugerkapazitäten immer mehr zu. Ein weiterer Grund für das Ansteigen der Strompreise dürfte das strategische Verhalten der Erzeuger sein, welches durch das Fehlen einer elastischen Nachfragekurve verstärkt wird. Einige Erzeuger sind versucht, während der Starklastperiode Kraftwerke nicht am Markt anzubieten, und damit den Strompreis weiter in die Höhe zu treiben (Chicken Game). Preisspitzen vor allem in den Wintermonaten sind die Folge.
Auf der anderen Seite werden die Vertriebsunternehmen aufgrund des Wettbewerbs bestrebt sein neue Kunden mit „günstigen“ Angeboten zu akquirieren. Durch dieses strategische Verhalten ist die Gefahr gegeben, dass die ohnehin knappe Leistung und Energie ineffizient verbraucht wird. Soll aber das Problem der knapper werdenden Erzeugerkapazitäten und der steigenden Nachfrage gelöst werden, so muss die Nachfragekurve des Systems betrachtet werden. Deshalb liegt es nahe die Verbraucherseite zu betrachten und zu untersuchen, welchen Einfluss eine elastische Nachfragekurve auf Preisspitzen und die effiziente Nutzung der Energie hat.

Die zentrale Frage dieser Arbeit ist nun, ob verbraucherseitige Maßnahmen die Marktperformance verbessern können und eine Alternative zum Kraftwerksbau darstellen?

Um diese Frage zu beantworten wurde ein volkswirtschaftliches Modell und Simulationstool entwickelt, welches die Auswirkungen von verbraucherseitigen Maßnahmen auf das Elektrizitätssystem unter der wichtigen Randbedingung Liberalisierung und Gefahr von Ungleichgewicht von Angebot und Nachfrage während Spitzenlastzeiten abschätzt.
Erkenntnisse gewonnen in dieser Arbeit zeigen, dass die Entwicklung der elastischen Nachfragekurve von zentraler Bedeutung ist, um die Marktperformance von liberalisierten Strommärkten zu verbessern.
Ergebnisse der Untersuchungen durchgeführt für Österreich zeigen, dass einige wenige und billige Maßnahmen (z.B. Energiesparlampe) zur Effizienzsteigerung, angewendet von 20% der Konsumenten, zu einer Lastreduktion von 250MW führen. Diese Reduktion ist günstiger für die österreichische Gesellschaft als ein neues thermisches Spitzenlastkraftwerk mit 250MW zu bauen. Die Nachfragereduktion von 250MW während Spitzenlastzeiten führt zu einer 6,3% Großhandelspreisreduktion in Österreich und verbessert damit die Funktion des Marktes.
Weiters zeigt sich, dass Übertragungsleitungen zwischen den europäischen Ländern ohne Kapazitätsengpässe kontraproduktiv für die Einführung von verbraucherseitigen Maßnahmen sind. Die Erweiterung der Übertragungsleitungen zwischen den europäischen Ländern unterstützt nicht die Anwendung von neuen Last-Management Programmen, wenn diese Programme nur in einigen wenigen europäischen Ländern durchgeführt werden.

Abstract

The EU directive which liberalized the European electricity market has been changing the supply structure enormously. A major goal of this directive was to provide low electricity prices for the whole economy. However, currently it seems that the electricity price will increase rapidly to very high price levels.
Hence, as a result of the liberalization process utilities had to change their behavior, selling their electricity at marginal costs and not at average costs as in the past.
Therefore, places at which electricity is traded - so called spot markets – get more and more important. Such spot markets serve as price indicators for electricity tariffs charged by suppliers. Empirical investigations of several spot markets show that electricity prices get higher and more volatile. This is especially true for on-peak prices as a result of lack in supply during on-peak hours the gap between on-peak prices and off-peak prices increase considerably. A further reason for the increasing on-peak prices and price spikes seems the strategic behavior of some sellers. The missing possibilities of consumers to react to price signals (= inelastic demand curve) provokes the threat of strategic prices. Some sellers withhold power plants during periods with high demand and as a result of this all sellers gain higher profits (so called chicken game).
On the other hand due to higher competition in the sales market segment utilities are endeavored to attract new costumers. Therefore, utilities lure with new "attractive" and cheap offers which may decrease the energy efficiency of the end-consumer sector. Because of this strategic behavior the observed problem of imbalance between supply and demand will further increase.
In order to manage the observed problems of imbalance between supply and demand a consideration of the elastic demand curve seems necessary. For a sustain electricity system which contributes to the Kyoto target and without unusual high price spikes during peak times a consideration of the elastic demand curve (and investigations of the corresponding energy efficiencies) can help.

Therefore, the core objective of this thesis is to answer following question: Do demand-side (DS)-measures increase the market performance and are they an alternative to new thermal on-peak power plants?

To answer this question a theoretical framework and software tool was developed which investigate the costs and benefits of demand-side-measures. A model to estimate the effects of load reducing DS-measures on the whole electricity system under the expected increasing lack of supply during on-peak hours is developed in this work.
Investigations performed in this work indicate that the development of the demand curve is of core relevance for the achievement of a functioning competitive electricity market, its corresponding market performance and market price. Furthermore, to implement a market which contributes to the Kyoto target a consideration of the demand curve and its corresponding energy efficiency is absolutely necessary. The results of all investigations performed in this work indicate that the increase in energy efficiency - by investing in few very simple and cheap DS-measures (e.g. high efficient bulb) - lead to a load reduction of 250MW which is cheaper for the Austrian society than the construction of a new thermal power plant with a capacity of 250MW. These measures applied to the Austrian electricity system can be used to reduce the expected increasing lack of supply during on-peak hours and result in an on-peak wholesale price reduction by about 6.3%. Furthermore, interconnections between countries without any transmission congestion are counterproductive for the application of DS-measures. The extension of the transmission network between European countries does not contribute to an increase of Demand-Side-Management (DSM) programs if only few European countries invest in DS-measures.

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1 Introduction

1.1 Motivation for this work

The liberalization of the European electricity market has been changing the supply structure of Europe enormous. A major goal of the EU directive which regulates the liberalization of the European electricity market was to provide low electricity prices for the whole economy. However, currently it seems that the electricity price will increase rapidly to very high price levels.

As a result of the liberalization, places at which electricity is traded, so called spot markets, emerged. At such spot market places electricity is traded in a short term day ahead market for all hours for the next day. The intersection between supply and demand on the market creates a market price for each hour of the next day. The calculated market price indicates the marginal costs of the whole electricity system. Therefore, such spot markets serve as a price indicator for electricity tariffs charged by suppliers. But, empirical investigations of several spot markets show that prices increase and get more and more volatile. Especially, the on-peak price spikes are considerable. Average on-peak price spikes about 60€/MWh and more are common. As a result of lacks in supply during on-peak hours the gap between on-peak prices and off-peak prices increase considerable.

In the past under regulated conditions electricity was sold at average costs. Now in the liberalized market with an economical point of view electricity should be sold at marginal costs and not at average costs or strategic prices. However, the missing possibility of consumers to react to price signals (=fully inelastic demand curve) provokes the threat of strategic prices (see also /24/). Therefore, a further reason for the observed increase in electricity prices seems the strategic behavior of few utilities[1]. Some sellers withhold power plants (e.g. because of faked maintenance) during periods with high demand and as a result of this all sellers gain higher profits (so called chicken game). The incentive to withhold capacities during off-peak[2] hours is minor (so called Prisoners' Dilemma). This strategic withdrawal of plants increases the on-peak price further (see also /35/ and /22/). This threat of strategic prices is supported by the fact that consumers have only restricted possibilities to react to price spikes. Therefore, it seems necessary that consumers have the possibility to react to price spikes and contribute to the increase of market performance. In any case consumers need to see market prices otherwise there is no information flow and no demand response.

Overcapacities built under regulated conditions in the past get more and more offline. As a result of the volatile markets no secure money flows are predictable for the utilities. Therefore, since 1999 power plants have been closed dramatically in whole Europe.

[1] The term utility indicates a company which is involved in production, transmission, and distribution. Since the liberalization this term is outdated. However the word "utility" is still frequently used.

[2] In practice the definition of on-peak and off-peak depends on the country considered. On-Peak: 08.00 hours to 20.00 hours for Germany and Austria.

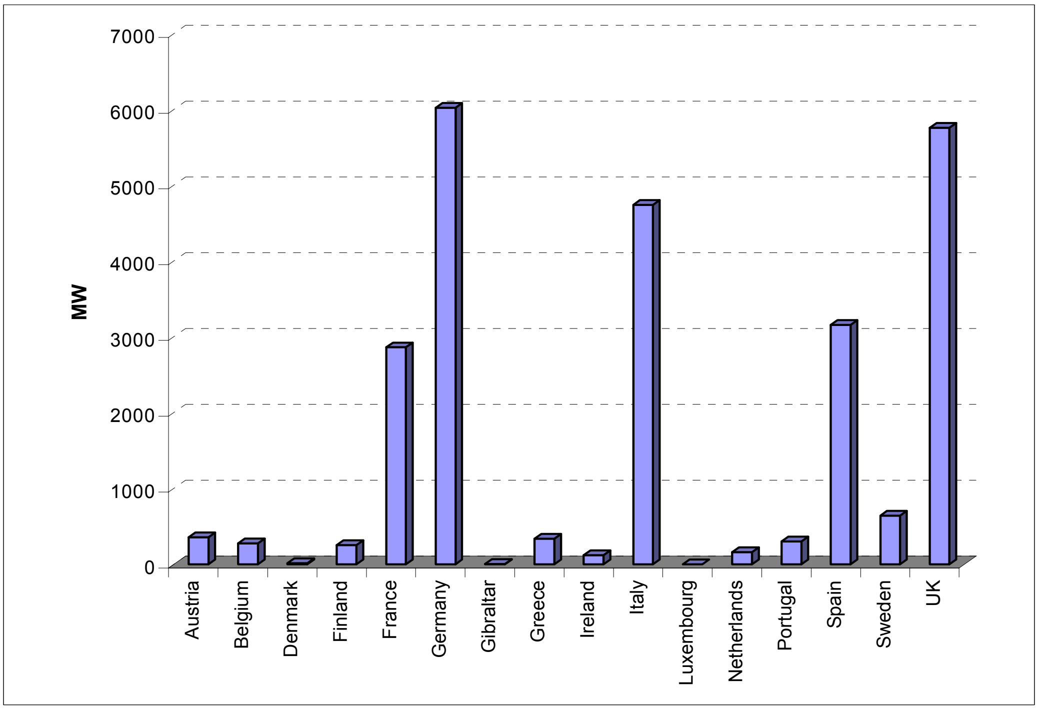


Figure 1.1: Planed decommissions of power plants for EU-15 countries because of high age till 2010. Source: /15/

Figure 1.1 shows the planed decommission of power plants for Europe till 2010. With these plants being closed down in the near future 25GW will go off-line in the EU-15 countries. Of course, new power plants are under construction. A vast part of the decommissioned plants will be coal fired plants. However, most of the European countries do not have enough water availability to compensate the decommissioned power plants with run-of-river or storage plants. The only alternative are new nuclear stations, new renewables (as wind) or Demand-Side-Management (DSM)-programs (The term DSM includes efficiency increasing measures and Load-Management-measures, see also chapter 2.3.1). The construction of new nuclear power stations seems too difficult as a result of the increased conservation-conscious in Europe. The only solution for this situation is to consider DSM-programs or new renewables.

Due to the decreasing capacities and the yearly increasing demand (power) the lack of supply during on-peak hours will further increase.

Due to the higher pressure in the sales market segment the utilities are endeavored to win new costumers. Therefore, the utilities lure with new "attractive" and cheap offers which might decrease the energy efficiency in the customer sector. For example, some utilities in Austria promote a trend for new electrical heating systems in low energy houses. A trend to the *"All electric household"* in kind of direct electrical heating systems is recognizable. This promoted additional electricity (power) consumption intensifies the observed problem of lacks in supply[3].

As a result of all observed market problems a consideration of the demand curve seems obvious to strike a balance between supply and demand. For a sustainable electricity system which contributes to the Kyoto target and without unusual high price spikes a consideration of the demand curve (and investigations of the corresponding energy efficiencies) is compulsory.

[3] Note a "lack in supply" is equivalent to the term "to much demand". The designation "lack in supply" shows impressive the "old" opinion that only new power plants can manage an imbalance between supply and demand.

1.2 Goal of this work

The core objective of this work is to answer following question: Do demand-side (DS)-measures increase the market performance of liberalized electricity markets?

Consequently, following further questions have to be answered:

- Are demand-side-measures an alternative to new thermal on-peak power plants?
- What are the costs of these demand-side-measures compared to the costs of thermal on-peak power plants?
- Who gains from demand-sides-measures?
- What is the achieved price and demand reduction because of demand-side-measures?

To answer theses questions a theoretical framework and software tool was developed which investigate the costs and benefits of demand-side-measures. A simple model to estimate the effects of load reducing DS-measures on the whole electricity system under the expected increasing lack of supply during on-peak hours is shown. The developed formal framework shows the basic economic relationships between demand-side-measures and costs for customers, costs for society, change in consumer surplus, change in producer surplus, load reduction as well as new national market price because of an elastic demand curve for any hour.

Furthermore, all for the investigation necessary data are collected in this work:

- Historical trends of spot market prices for six different European countries
- Forecast of future wholesale prices during on peak hours till 2010
- Current supply structure (curve) for Austria
- Expected future supply structure for the year 2010
- Derivation of demand curves:
  - The short term demand curve because of load shifting in the residential sector and
  - The aggregated long term demand curve because of investments in demand-side-measures for the commercial, public and residential sector
- Forecast of Austrian electricity demand (power demand) without any DSM-programs till 2010
- Experiences with dynamic tariffs (Real-Time-Pricing and Time-of-Use tariffs) are documented

1.3 Most important literature

The beginning of detailed investigations on demand-side-measures and load management can be backdated to the 1980ies. The most important technical and economical investigations were made in the US and Germany. At this time the trade mark “Demand-Side-Management” was defined in the US (see also “Demand-Side-Management”, EPRI Report Vol. I, Overview of key issues, Palo Alto 1984).

However, the formal framework of peak load pricing can be backdated to the late 1950ies. The model of Steiner (1957) and Williamson (1966) are the basis for modern peak load pricing. The theoretical framework for the implementation of Time-of-Use tariffs and Real-Time-Pricing was determined by Crew-Kleindorf (1979) who pointed out that on-peak prices should be higher than off-peak prices.

The gathered information of experiments performed in the 1980ies and 1990ies under the important boundary of regulation are very useful as an empirical basis for this work. In this context following literature is important: "Arbeitsgemeinschaft Tarifstudie Saarland, Frauenhofer-Institut für Systemtechnik und Innovationsforschung, Infratest Sozialforschung, Sinus*: Die Tarifstudie Saarland* – Endbericht, März1992*", „Zeitvariable lineare Stromtarife – eine empirische Untersuchung im Versorgungsgebiet der Berliner Kraft- und Licht (BEWAG)-Aktiengesellschaft,* Berlin, Juni 1993*" and „Der Wiesbadener Modellversuch – Linearer Stromtarif mit zwei Zeitzonen*, Abschlußbericht, Wiesbaden, März 1994".

From the mid 1990ies to early 2000 demand-side-measures and load management were not a big issue. However, the California energy crisis has led to a renaissance of DSM-programs. The reasons of the California energy crisis and the impact on Europe are discussed in Haas/Fereidoon/Sioshansi/Auer (2001). Now, in contrast to the investigations in the 1980ies and early 1990ies the impact of demand-side-measures on market prices are the most interesting issue (see also Faruqui (2001), Lam (2000), Auer/Tragner/Haas (2000)).

A missing demand curve – e.g. determined by demand-side-measures - seems a very important factor on strategic prices set by suppliers. Haas (2003) shows how important it is to give consumers the possibility to react to price signals.

1.4 Organization of work

Chapter 2 describes the demand curve in principle and shows the general construction of the demand curves considered in this work. Furthermore, the *"Rebound Effect"* is shortly discussed. Because of the *"Rebound Effect"* the electricity consumption increases with increasing energy efficiency.

Chapter 3 describes the development of the basic model. The different scenarios: congested lines between Austria and its neighboring countries and non congested lines are developed. Also, preliminary results derived from the models are discussed.

Chapter 4 describes the current spot market trend as well as the international experiences with dynamic tariffs. Additionally, a short discussion about different customer clusters is performed. However, the most important part in this chapter is the development of the aggregated long term demand curve for the commercial, public and residential sector. Furthermore, the current Austrian supply curve has been developed.

Chapter 5 includes the power demand forecast without any DSM-measures for Austria till 2010, the on-peak price forecast for winter months till 2010 and the expected supply curve in the year 2010.

Chapter 6 describes the implementation of the developed models in the programming language Visual Basic 6. Additionally, also the most important algorithm are described.

In contrast to chapter 6 chapter 7 describes the operation of the software tool "NESoDSM". The most important features of the program are shown.

In chapter 8 sensitivity analyses for on-peak hours are performed with simulating a low price, medium price and high price scenario. These scenarios lead to the important conclusions for chapter 9.

Finally, Chapter 9 summarizes the most important conclusions of this work.

2 Impact parameters on electricity demand in liberalized markets

2.1 General point of view

In practice, the generation of a demand curve is more complicated than the derivation of a supply curve. It is very difficult to quantify the amount of demand and the regarding costs. Because in general no empirical data on the demand curve are available. Hence, the determination of the aggregated Austrian demand curve is one of the most difficult parts of this thesis. The detailed derivation of the Austrian demand curve is the major object of chapter 4.5 and 4.7.

In general consumer demand depends on:

- The country (region, climate)
- Time (demand is not fixed in time)
- Electricity price (above given parameters do also influence more or less the price, price depends on marginal costs of generation)
- Income
- …

Historical analyses show following results (at least for periods with continuous increasing price):

- Demand decreases with increasing price, i.e. consumers of the residential, commercial and industry sector react on changes in price. The reaction is defined by the price elasticity.
- The reduction in electricity demand can be caused by two reasons:
  - Reduction in service demand (private consume – residential sector)
  - Higher efficiency due to demand-side-measures
- The price elasticity decreases with time and income.
- The price elasticity is asymmetric. In general the price elasticity gets less with decreasing price[4] compared to increasing price. The asymmetric of price elasticity can be explained by the lack of incentive to save energy in periods with decreasing price and the fact that already implemented DS-measures will not be reversed.
- The price elasticity depends on absolute price level.

$$Price\ elasticity\ \alpha = \frac{\frac{dQ}{Q}}{\frac{dP}{P}} \qquad \textbf{(2.1)}$$

dQ *Change in demand*
Q *Absolute demand*
dP *Change of price*
P *Absolute price*

[4] In the case of decreasing prices evidence is given that no significant price elasticity exists (see also chapter 5.1.3.3).

2.2 The Rebound Effect

Most of investigations performed on efficiency increasing measures do not consider consumers' behavior and therefore calculated demand reductions are mostly higher than real reductions. Hence, a short discussion of the so called Rebound Effect is given to show the effect of consumers' behavior on demand reduction. A more comprehensive discussion of the Rebound Effect is given in Appendix A.1.

The Rebound Effect is based on the assumption that the consumer uses a service instead of electricity (kWh). This approach is in contrast to most economical and technical investigations.

$$\textit{Service } s = \eta \times e \qquad \textbf{(2.2)}$$

η *Efficiency of the energy (electricity) usage*
e *Energy (Electricity) [kWh]*

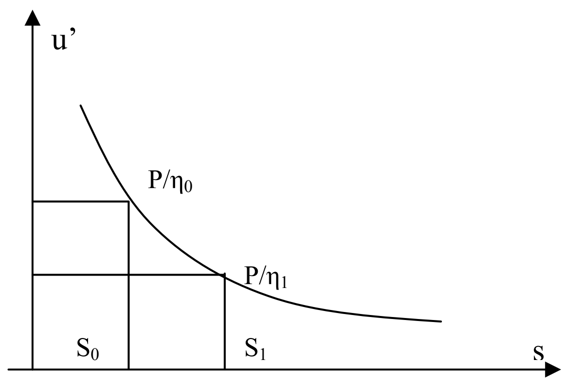
The consumer is mainly interested in a certain service and benefit like room temperature or a certain mileage performance of a car.

$$u = u(s) = u(e\eta) \qquad \textbf{(2.3)}$$

u *Benefit of the usage of service s*

The major claim is that demand-side- measures, e.g. an increase in energy efficiency may not necessarily lead to a proportional decrease in demand of electricity. The increase in energy efficiency leads to an increase in service demand (e.g. room temperature) as defined by (2.3)

$$u' = \frac{p}{\eta} \qquad \textbf{(2.4)}$$



With the assumption of a constant price and due to the consumption of service instead of energy and the conditions for the function u the service (s) increases with higher efficiency. A very illustrative example is a diesel-car versus gasoline-car regarding mileage performance (service). The best reason for buying a diesel-car is seen in its high mileage performance. Therefore, people with a low mileage requirement normally buy a cheaper (inefficient) gasoline car.

Figure 2.1: The influence of higher efficiency ($\eta_1 > \eta_0$) to the service demand with constant price

Increase in efficiency raises service demand. But, in addition to this "direct" Rebound Effect, which is always linked to the same service (room temperature, mileage performance), also a "Cross Rebound Effect" exists. That means an increase in efficiency for service A may lead to an increase in service B because of the limited Income (M).

Because of (2.4) two advantages according to the increase of consumer efficiency exist. The consumers gain because of:

- Reduction in „fuel" costs due to the lower consumption[5] of electricity or energy and
- The increase in service.

However, because of the considered efficiency increasing measures in this work the Rebound Effect has only a minor relevance on demand reduction.

2.3 Principle derivation of the demand curve[6]

In the same way as the supply curve is separated in a short term and long term curve also a division in short term and long term demand curve is used.
The short term demand curve reflects reactions to price changes without any investment in DS-measures.

In contrast to the short term demand curve the long term demand curve represents all reactions to price changes with investments in DS-measures.

2.3.1 Definition of the term Demand-Side-Management (DSM)

The term Demand-side-Management (DSM) is a trade mark and includes following measures:

- Efficiency increasing measures (high efficiency bulb, efficiency increase in heating, systems, low energy house,…). The term efficiency increasing measures is equivalent to the term demand-side-measures.
  The efficiency measures leads to a real energy reduction during a certain period (e.g. year) and due to the reduction in energy consumption to a CO_2 reduction[7].
- Load management measures (Time-of-Use tariffs[8], Real-Time-Pricing, Interruptible loads, Distributed generation and µ-grids (see also /14/), internet controllable loads,…)
  In contrast to efficiency measures load management measures are merely load shift measures because the shifted on-peak power (or energy) is consumed during off-peak hours. These measures are used to manage lacks in supply during peak hours. No CO_2 reduction is achieved.

This definition of DSM is mainly driven by investigations made in the US. In Europe a different definition of DSM exists which is not used in this work.

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[5] A necessary and sufficient condition for a decreasing electricity consumption due to higher efficiency requires an inelastic service demand with –u'/(u''s) negative.
[6] At this point I want to thank my colleague Dr. Claus Huber for his contributions and ideas.
[7] But, only if no one else consumes the reduced energy. This means the energy supply has also to decrease due to the increase in efficiency.
[8] Time-of-Use tariffs and Real-Time-Pricing result in efficiency increasing measures. Without any price signal no incentive for the customer exists.

2.3.2 Short term demand curve

Naturally, the short term demand curve is very steep. Therefore, in all further investigations with the simulation tool "NESoDSM[9]" the short term demand curve is neglected (see also chapter 3). That means that the short term demand curve is assumed to be fully inelastic. The steep short term demand curve for the residential sector is empirically shown in chapter 4.5.

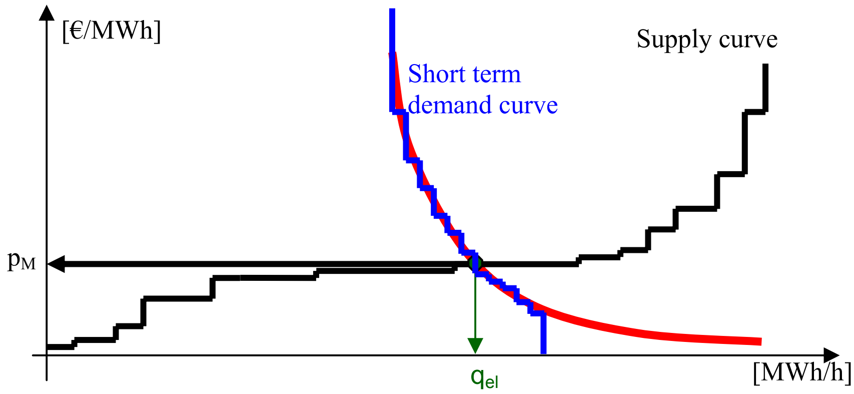

Figure 2.2: Modeling of short term demand curve

p_M Market price
q_{el} Electricity demand

2.3.3 Long term demand curve

The generation of the general long term demand curve is very easy. For each measure costs are assumed (reduction costs) for the implementation and the reduction potential. Once the relevant measures for each sector (household, commercial, industry and public) are found a merit order list of all measures can be created. As shown in Figure 2.3 the merit order list of the reduction potential can be subtracted from the actual demand and the resulting curve is the demand curve.
Each measure with reduction costs below the assumed market price is assumed to be already achieved. All DS-measures above the assumed market price are not achieved because reduction costs higher than the market price. It is imperative for this approach that the consumers are able to see the market price or an indicator of the market price (e.g. Time-of-Use tariff). An information flow between utilities and customers is absolutely necessary. The lack of information (e.g. frozen end user tariffs in California) may destroy a liberalized market (see also /22/).

[9] National Economical Simulation of Demand-Side-Measures

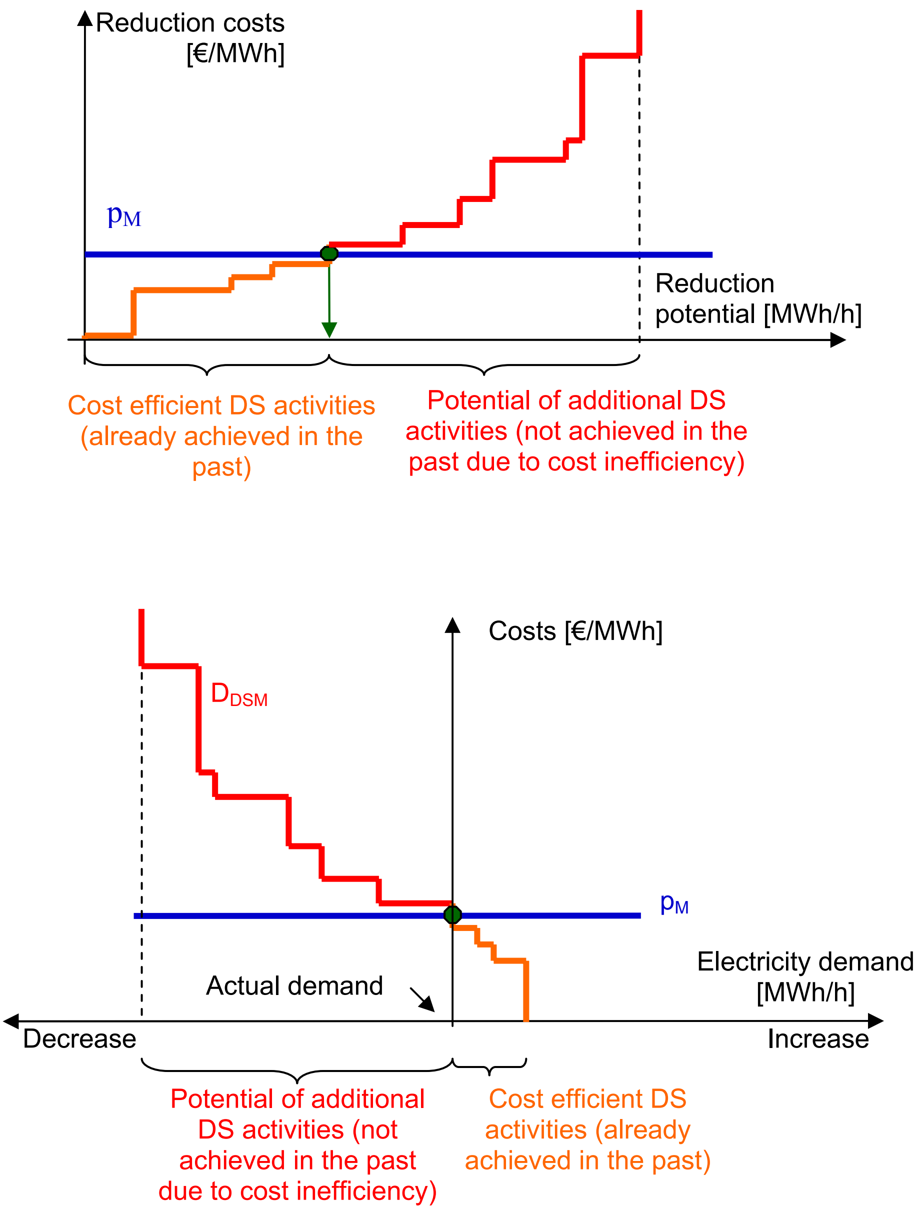

Figure 2.3: Derivation of the long term demand curve

With following abbreviations:
p_m Market price
DS Demand-side
D_{DSM} Demand curve resulting of demand-side-measures (long term demand curve)

As mentioned before the generation of the long term demand curve in principle is quite easy. But, due to missing empirical data/investigations and large numbers of DS-measures the detailed aggregated demand curve for Austria is very difficult to find. A comprehensive derivation of the long term demand curve for Austria is given in chapter 4.7.

2.3.4 Total demand curve

The short term and long term demand curve are summed up horizontally to the total demand curve (green curve). Without any additional incentive (e.g. subsidy) for DS-measures no change in demand can be obtained. This means all cost efficient DS-measures – with costs below the market price - are already achieved.

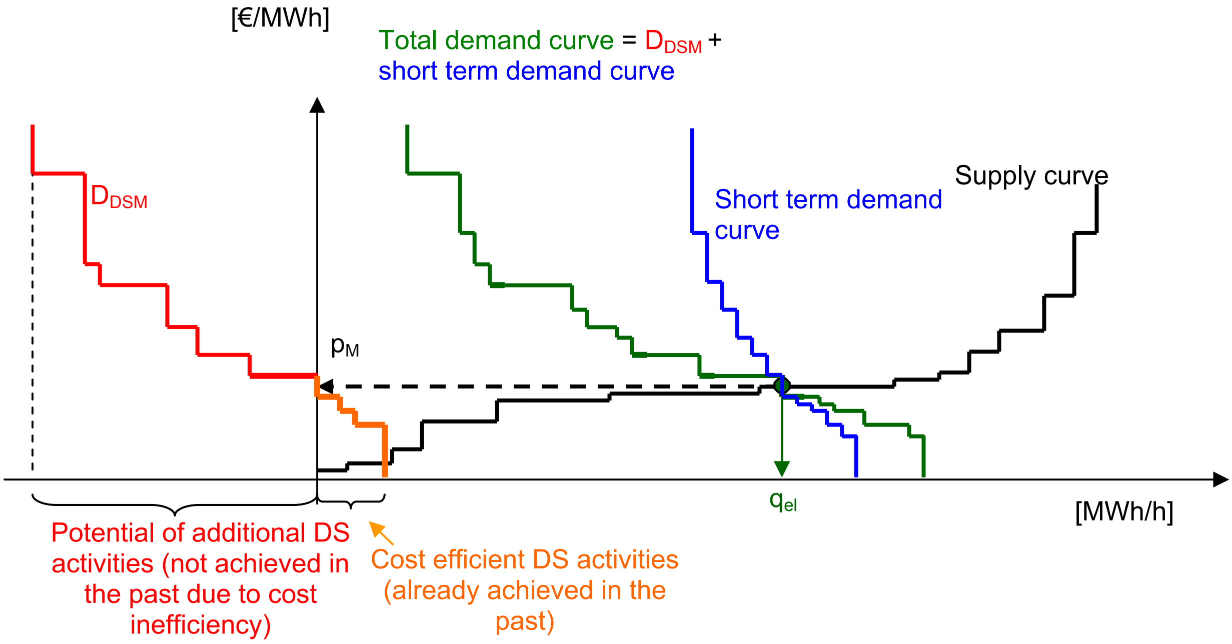

Figure 2.4: Creation of the total demand curve from the short and long term demand curve, without any additional incentives (e.g. subsidies) for DS-measures

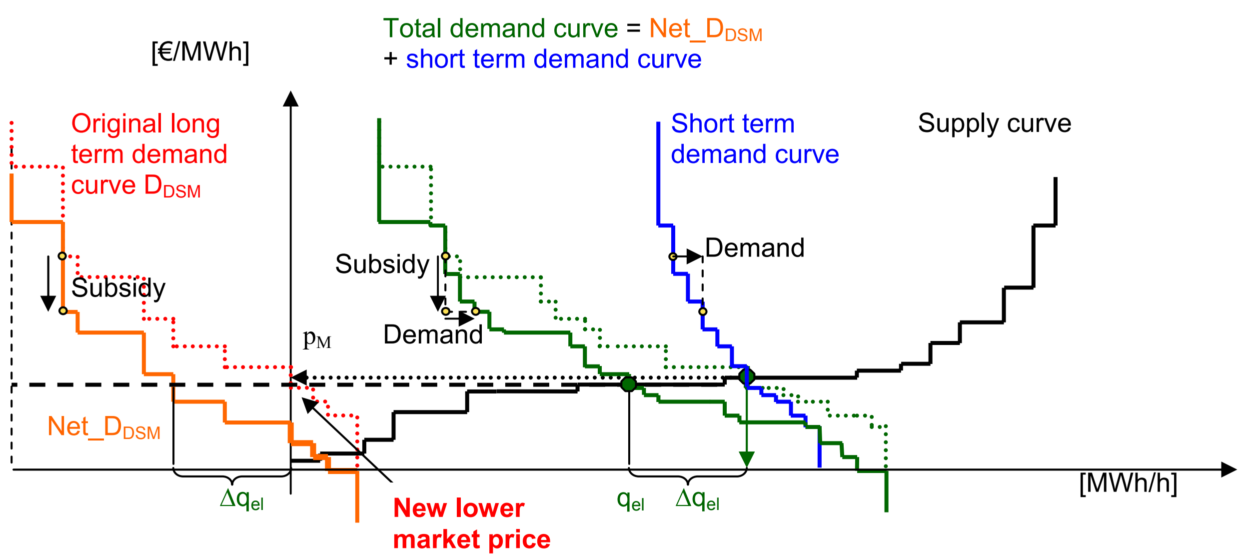

Figure 2.5: Creation of the total demand curve from the short and long term demand curve, with additional incentives[10] for DS-measures

[10] To make the illustration easier to understand the subsidies for all DS-measures are assumed to be equal.

The subsidy of the long term demand curve results in a change of the short term demand curve. Because, lower costs (prices) increase the short term consumption. Therefore, in the case of subsidies the horizontal addition of the two demand curves must be realized after subtracting the subsidy from the original long term demand curve (D_{DSM}).

Because of the subsidy new DS-measures are implemented resulting in a decline of energy consumption which leads to a decrease in market price! In the former monopoly system with flat tariffs and regulated prices the price of electricity was mainly fixed by the supply.
According to this consideration demand can influence the market price. Now, supply and demand are responsible for the market price.

2.3.4.1 The importance of the market price

The important parameter of this approach is the market price. A higher market price supports the introduction of new DS-measures.
Therefore, two possible strategies for the government or regulator exist:

- Do nothing and wait until the price is high enough for new DS-measures. However, this approach is in contrast to the main reason for the liberalization of the electricity sector to get low electricity prices for everyone.
- Give subsidies for DS-measures in order to make DS-measures cheaper than the market price. However, this means that subsidies are paid by the community.

3 Formal framework

3.1 General point of view

In this chapter the basic formal framework for this work is presented.

The basic economical relationships in Austria between Demand-Side-measures (DS-measures) and costs for customers, costs for society, change in consumer surplus, change in producer surplus, load reduction as well as new national market price because of demand response for any hour will be shown.

The major goal of this framework is to model the costs and benefits of load reducing measures. Furthermore, the simple model estimates the effects of load reducing DSM-measures on the whole electricity system for different scenarios of decreasing generation and transmission capacities.

An important influencing factor of the model is the liberalization of the electricity market in Austria in 1999. The possibility to buy electricity at different market places and the increase in transmission congestion between these places (countries) will influence the model enormously.

The economical models shown in this chapter are implemented in the software tool "NESoDSM"[11]. With these models and the software tool as well as the empirical data gathered in this work representative examples for on-peak hours during winter months are simulated in chapter 8.

The two developed models use an international spot market price indicator as a reference market price. Because of transmission congestion and different supply structures in different countries no unique European spot market exists. But, due to the closelyness of Germany which results in the same electricity price levels as in Austria (see also chapter 4.2.6) Germany is used as the international spot market price reference for this work.

Depending on transmission congestion between the European spot market (Germany) and Austria two basic models are considered:

- National spot market price = international spot market price: That means no transmission congestion and transaction costs exist between these two market places. No barriers exist.
  This approximation provides a very simple and robust model to estimate quickly any situation with no transmission congestion.
  The Austrian customers invest in on-peak reducing DS-measures and because of the missing barriers between the countries and the fixed market price[12] the in Austria reduced on-peak load is exported by the utilities to Europe leading to CO_2 emission reductions somewhere else in Europe.

- National wholesale price ≠ international reference price: Because of the costs for electricity transmission the national price differs from the international price.

[11] National Economical Simulation of Demand-Side-Measures
[12] The Austrian demand is assumed to be too less to change the European market price. See also chapter 3.2.1.

Hence, that means the national market price and the regarding tariff[13] as well as the electricity supply in Austria can be only influenced by barriers between networks. These barriers can be congestions in transmission networks, transaction costs for electricity trading or political introduced transmission tariffs between the countries.

3.2 Formal framework in detail

3.2.1 Assumptions used for the formal framework

In order to design a robust and fairly simple model some assumptions are necessary:

- The international electricity price is not influenced by the Austrian supply and demand.
- The short term demand curve is not taken into account, because it is assumed to be fully inelastic.
- Demand-side-measurers which are a shift (s) measure are considered as CO_2 neutral: It is assumed that the shifted load produces the same amount CO_2 as the original load.
- Money from taxes paid by all consumers is dedicated to a certain pool, which is used to support DS-measures (Electricity producers do not pay anything for DS-measures).
- Transmission costs are considered to be the same for imports and exports.
- Short term imports from the European day ahead market (spot market) are marginal
  → National demand ≈ (National demand + imports from international spot market):
  This assumption is made because of following reflections: The Austrian supply curve differs from the most European supply curves because of its storage plants. Approximately 30% of the total installed capacities in Austria are covered by hydro storage plants. These cheap storage[14] plants are used to deliver electricity during on-peak hours to the markets[15]. But, the transmission of electricity inside of Austria may be cheaper than the transmission to Europe (congestion and transaction costs!). Therefore, it is assumed that it is cheaper to sell electricity from the storage plants to the Austrian spot market. The imports from the European spot market are marginal during on-peak hours.
- No imports (long term & short term) between L_2 and L_1:
  Long term contracts are settled below L_2 (= new demand with DS-measures) and imports from the spot market are settled above L_1 (= demand without DSM).
  Long term contracts in winter months are assumed to be slightly cheaper than the regarding Austrian thermal power plants. A reason for the lower price is the longer planning horizon for the seller of a long term contract. A fixed quantity for a certain future time period reduces the uncertainty regarding to the income for the seller. Of course in the long run the price for the long term contract will approach the price level of the thermal electricity produced in Austria.
- (In any case consumers need to see market prices otherwise there is no information flow and no demand response).

[13] Real-Time-Pricing and Time-of-Use tariffs

[14] The costs for electricity production from storage plants are very low. Because of the high age of the storage plants no fixed costs for loans are considered in the marginal costs. Only the variable costs have to be considered. But, the short term marginal costs are very low. Therefore, in this work the costs for electricity production from storage plants are neglected. But, price and cost are not the same. Storage plants are used to supply electricity during on-peak hours. Therefore, the reference spot market price determines the price for one kWh electricity produced by storage plants.

[15] Beside the possibility to sell the electricity short term to the spot market also the possibility exists to sell electricity via long term contracts to a certain utility.

3.2.2 Definitions

P	European spot market price [€/MWh] for model 1. Price without transmission costs
P_E	International electricity price without transmission costs for model 2
C_T	Costs for the electricity transmission. C_T = f(transmission congestion, time, opportunity costs)
P_T	Electricity price with transmission costs for model 2. This price is the entire price for the Austrian utilities
L_1	Original demand (load) without DSM
L_2	National demand (load) with DS-measures
L_2’	National demand (load) with DS-measures for model 2 – case 2b
ΔPS	Change in the producer surplus because of DS-measures compared to the case without DS-measures
ΔCS	Change in the consumer surplus because of DS-measures compared to the case without DS-measures

3.2.3 Model 1 with exogenous fixed market price[16]

In the following the developed model is described in more detail.

The inelastic original demand curve was replaced by the
- long term demand curve because of investments in DS-measures and
- a new short term demand curve. This new short term demand curve is assumed to be fully inelastic as described in chapter 2.3.2.

With this assumption consumers can react on price signals from the market. If the price is high long enough the consumers will invest in DS-measures to reduce the electricity bill or regain the loss in service as a result of the short term demand curve.
The reduction of the load is linked to certain measures and costs. Practicable DSM-measures are:
- Introduction of new technologies for the load management (e-commerce, Power Line Carrier (PLC), Global System for Mobile communication (GSM), and so on).
- Application of standards to increase the energy efficiency.
- Application of interruptible appliances. These appliances can be controlled by the Internet and the supplier. If the price is high the appliance is switched off automatically. Such appliances are washing machines, driers, freezers (only for a short time), heating systems, air conditions, and so on.
- Distributed generation linked to interruptible loads.
- Switch from electricity to another energy sources (gas, oil,..).

However, consumers will only invest in DS-measures if they see the real electricity price in kind of Time-of-Use (TOU) tariffs or Real-Time-Pricing (RTP). Without any indicator for the actual energy price no sensitive exists to invest in DS-measures.

[16] In this formal framework national market price is equal international market price. Therefore, no differentiation between national and international market price is used.

All these described measures result in an elastic long term demand curve. However, before the new long term demand curve can be inserted in the model the supply curve has to be fixed horizontally. The European spot market price must be equal to the marginal power plant in Austria. Each power plant above P is more expensive than the international reference price. From an economic point of view it is cheaper to buy electricity at the spot market than to produce it in Austria.
With the assumption that the marginal power plant does run with full power the European spot market price must intersect with the supply curve in the step from the marginal power plant to the next plant in L_1. The European spot market price and the original load without DSM (L_1) fix the horizontal position of the supply curve and determine the available capacity of all theoretical available power plants (see figure below).

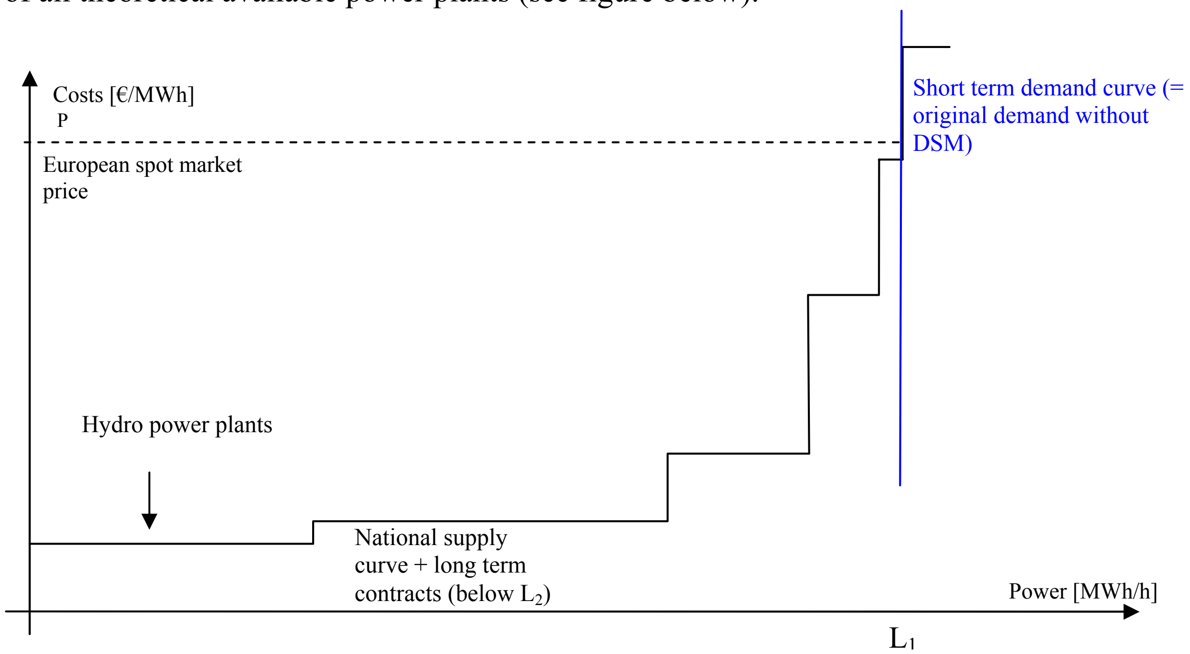

Figure 3.1: Determination of model 1, step 1. National supply curve and original demand curve without DSM (= new short term demand curve)

The next step is to insert the long term demand curve in the model. All DS-measures which are cheaper than the market price are assumed to be used by the consumers. All achieved measures must be located on the right side of the intersection point between P and the original demand without DSM (see Figure 3.2).
All DS-measures which are on the left side of the intersection point between P and the original demand without DSM (blue line in Figure 3.1) are too expensive to get achieved[17]. The costs for the intersection are higher than the market price. The saving of energy is more expensive than the consumption of the electricity. Therefore, no one is interested in additional energy savings.
This model assumes that if the costs for the implementation of a DS-measure are marginal lower than the market price the consumers will invest in this measure. This approach neglects the imperfect information flow and transaction costs for the new appliance. Not every

[17] Note, market prices without taxes are shown in the model. No tariffs are directly shown in the model. But, the customers get tariffs charged (TOU tariffs or RTP) and if a DS-measure is cheaper than the charged tariff it will be achieved. As a result of such a design the tariffs have to be converted to market prices. In practice the conversion factor is a function of the customer cluster (households, commercial, industry, and public), the region, yearly consumed electricity, volatility of electricity consumption, load factor and time. A detailed description of the customer clusters is given in chapter 4.4. The conversion of the tariffs to market prices is shown in chapter 4.7.3.

consumer has the full information about innovative products on the market. An example for such imperfect information flow is the high efficiency bulb. In chapter 4.7.2.1 the attractive application price for high efficiency bulbs is calculated. The calculation shows that each consumer in Austria must use high efficiency bulbs. But, in practice the number of used high efficiency bulbs is quite low. The reason for this behavior is that most of the consumers neglect the ten times higher lifetime of high efficiency bulbs compared to ordinary bulbs. Consideration of this imperfect information results to an attractive application price higher than the actual[18] electricity price (see also chapter 4.7.2.1).

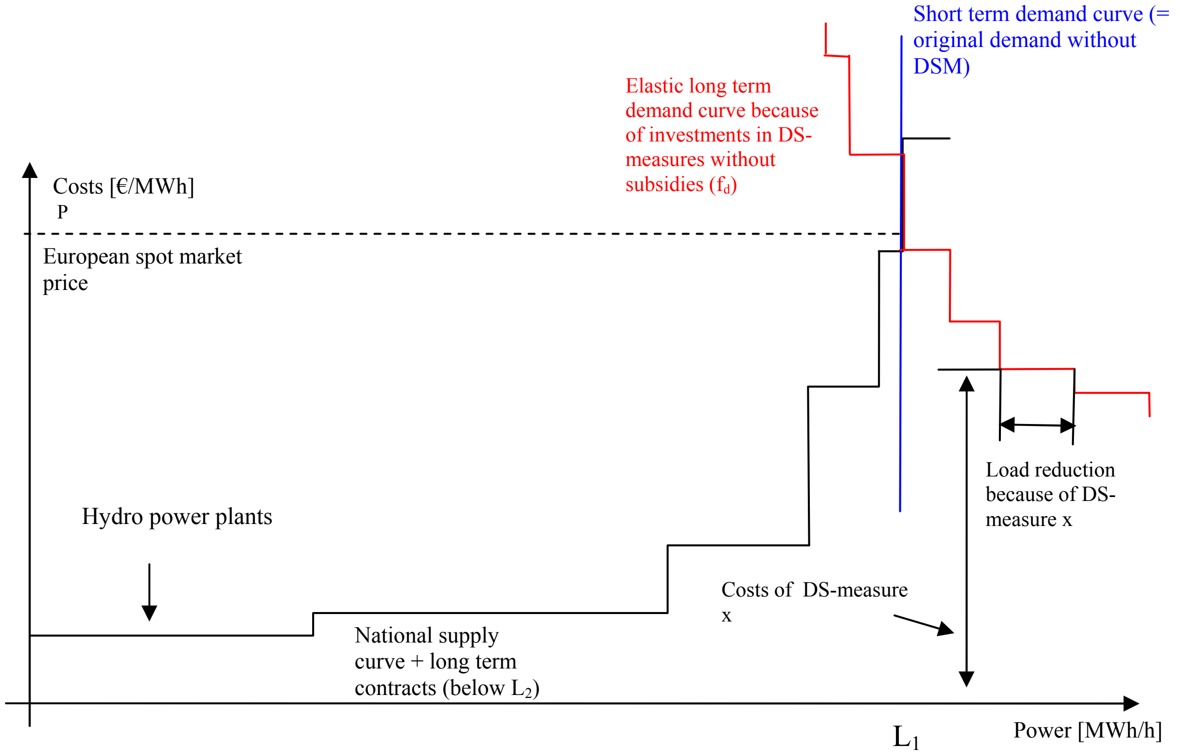

Figure 3.2: Determination of model 1, step 2. Insertion of the new long term demand curve

To get incentives to invest in DS-measures which are more expensive then the spot market price subsidies to the customers must be paid. All customers who are interested in DS-measures get money from customers who are not using TOU-tariffs (RTP or without interest in DSM-measures). That means all customers pay money in a pool and this money is dedicated to support DS-measures. Currently, in Austria an extra charge for small hydro power plants is in place. Such an extra charge for DS-measures can gather money for the necessary support of DS-measures.

The subsidies paid to the customers who are interested in DSM decreases the costs of DS-measures and the green demand curve in Figure 3.3 comes into being. Now some DS-measures are cheaper than the spot market price and the customers will invest in the regarding measures.
To show the creation of the model in a simple way equal subsidies for each measure are used. In practice different measures get different subsidies. But, different subsidies can change the merit order list of the demand curve. In some cases a new merit order list of the subsidized demand curve is necessary. This problem is discussed in chapter 6.1.3.1 in detail.

[18] In the year 2003

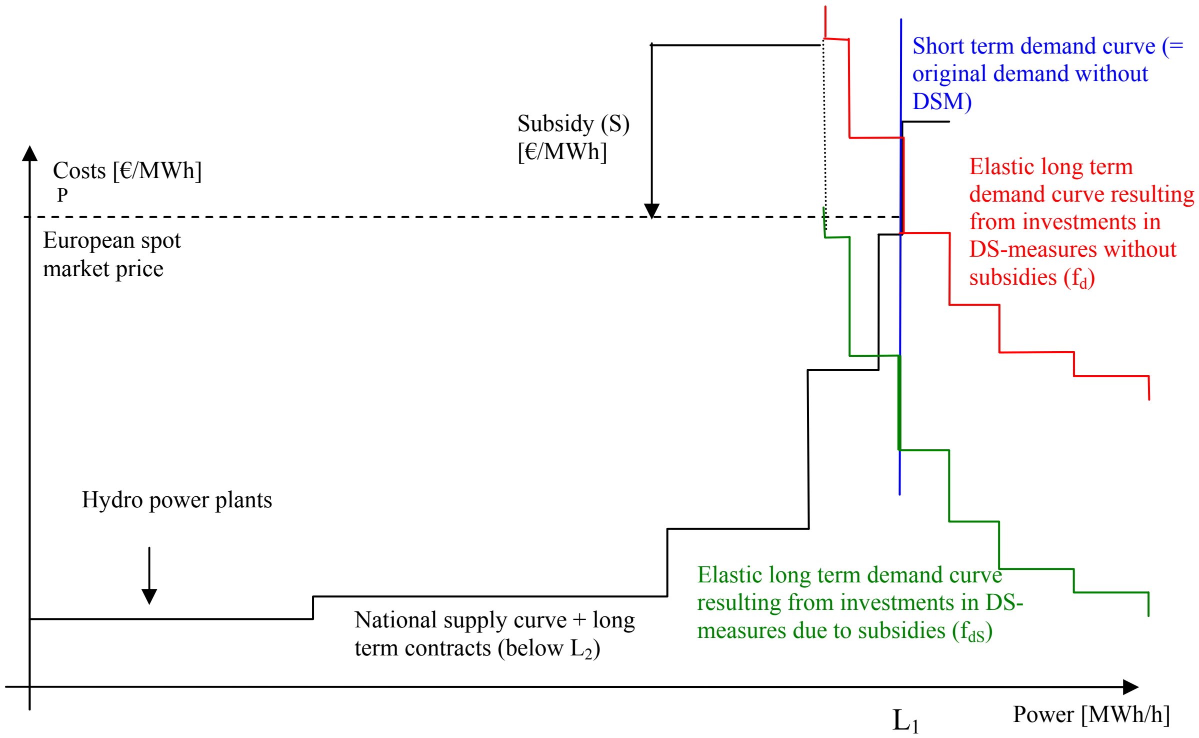

Figure 3.3: Determination of model 1, step 3. Creation of subsidized demand curve

The intersection point between the fixed market price P and the subsidized demand curve results in a new national load L_2. However, because of the assumption no transmission costs (C_T=0) and a fixed market price a certain amount (L_1-L_2) will be exported to Europe. The assumption C_T=0 means that no barriers between Austria and Germany exists and this results in the situation that utilities always identify the international market price as the national price.

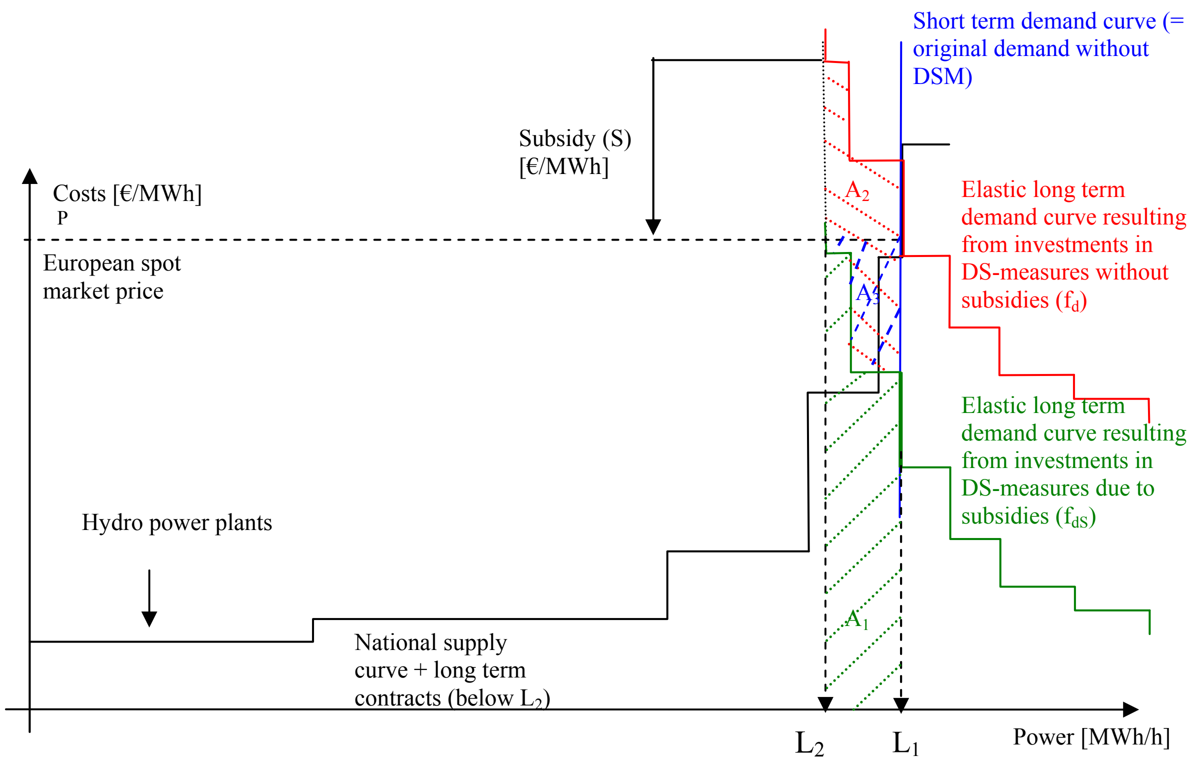

Figure 3.4: Determination of model 1, step 4. Economical values

A_1	The costs of consumers who are investing in DS-measures [€/h]
A_2	Subsidy [€/h]
A_3	„Gain" for customers who are investing in DS-measures because of subsidies and load reduction [€/h]
ΔCS_{NoDSM}	Change in consumer surplus for customers who are not interested in DSM [€/h]
ΔCS_{DSM}	Change in consumer surplus for customers who are investing in DS-measures [€/h]
ΔCS_{Total}	Change in consumer surplus for all customers [€/h]
α	Share of consumers investing in DS-measures [%][19]
f_d	Elastic long term demand curve resulting from investments in DS without subsidies
f_{dS}	Subsidized elastic long term demand curve
p	Reference price [€/MWh]
l	Load (Power) [MWh/h]

According to Figure 3.4 following economic values can be determined:

$$A_1 = \int_{L_2}^{L_1} f_{dS}(l)dl \quad \textbf{(3.1)}$$

[20]

$$A_2 = \int_{L_2}^{L_1} [f_d(l) - f_{dS}(l)]dl \quad \textbf{(3.2)}$$

$$A_3 = \int_{L_2}^{L_1} [p - f_{dS}(l)]dl \quad \textbf{(3.3)}$$

The calculation of A_1, A_2 and A_3 in practice is shown in chapter 6.1.4.

Due to the fact that the DS-measures get subsidized by one group of customers and the fact that A_3 is a part of A_2 (and therefore always less than A_2) the entire change in the consumer surplus must be negative.

$$\Delta CS_{NoDSM} = -A_2 \times (1 - \frac{\alpha}{100}) ... < 0 \quad \textbf{(3.4)}$$

$$\Delta CS_{DSM} = A_3 - A_2 \times \frac{\alpha}{100} \ldots > 0 \quad \textbf{(3.5)}$$

$$\Delta CS_{Total} = A_3 - A_2 \ldots < 0 \quad \textbf{(3.6)}$$

Because of the fixed market price and the export of the amount (L_1-L_2) to Europe no change in the producers' surplus results. The producers earn the same money as in the case without DSM.

$$\Delta PS = 0 \quad \textbf{(3.7)}$$

$$\begin{aligned}&\textit{Nationale economic}\\ &\textit{monetary gain} = \Delta CS_{Total} + \Delta PS ... < 0\end{aligned} \quad \textbf{(3.8)}$$

[19] The consideration of α is necessary due to the fact that <u>all</u> consumers pay money in a pool via taxes. Nevertheless, only a DSM interested consumer get money back from this pool.
[20] For a non steady step function a subdivision in steady sectors is necessary.

$$(A_1 + A_2) = \text{National economic expenditures for } DS \ldots > 0 \quad \textbf{(3.9)}$$

Without the consideration of external costs (e.g. for environmental damages) the national economic monetary gain resulting from DS-measures is always negative. The problem with such external costs is the estimation of these costs. What does it cost to save one tree or reduce one tonne of CO_2? This is a very difficult question.
One approach exists to internalize the "costs" of environmental damages. Starting with January 2005 emission trading is planned in Europe. Within this emission trading system each thermal power plant has only a restricted number of emission certificates. If the company exceeds the restricted number of CO_2 emissions penalty has to be paid by the supplier. This penalty might increase the costs of electricity production. Instead to transfer the penalty to Brussels the penalty can be used to support DSM directly. If the supplier recognizes that it may exceed the CO_2 restriction it can support DSM directly and handle in this way the danger of penalty. This procedure may turn the consumer surplus to positive values.

Nevertheless, this economic approach neglects the increase in jobs or income for companies which are involved in DSM. The higher demand in efficiency increasing measures because of subsidies (or high prices) results in the development of new innovative products. New market places for new products will appear, but nobody can estimate what the revenues of these new markets are.

3.2.3.1 Resume model 1

The Austrian market is assumed to be marginal compared with the European (or German) market. The Austrian supply and demand does not influence the international market price (condition of a perfect market).
This means that the amount (L_1-L_2) does not influence the German market. Because of the neglected transmission barriers between Austria and Germany no supply is reduced in Austria. The national reduced (shifted) load is exported to Europe leading to the situation that somewhere else in Europe the supply is reduced. Hence, Austrian consumers invest in DS-measures, but the regarding CO_2 reduction happens somewhere else in Europe. In other words Austrian customers subsidize CO_2 reductions in other European countries.

Therefore, in order to make DS-measures to a success for Austria it is necessary that:

a) DSM programs are in place in all other European countries or
b) Barriers between Austria and Europe are necessary to prevent the export of reduced load. Such barriers are natural transmission congestions, transaction costs or political barriers.

3.2.4 Model 2 (case 2a) with variable national market price[21]

Model 2 is characterized by transmission (and transaction) costs greater than zero (C_T>0). The transmission costs are considered to be equal for the import and export of electricity. As in model one the international market price is exogenous fixed and not influenced by the

[21] In this formal framework the international market price is exogenous fixed. But, because of transmission congestions or transaction costs the national market price is variable.

Austrian supply and demand. But, because of transmission costs the national spot market price is variable in the price band P_E-C_T.

Transmission costs for electricity increases the electricity price and Austrian utilities recognize the total electricity price $P_T=P_E+C_T$. Now, the total electricity price fixes the horizontal position of the supply curve. The total electricity price must intersect with the supply curve in the step of the marginal power plant to the next plant in L_1 as described in chapter 3.2.3. The insertion of the demand curve and subsidized demand curve happens in the same way as for model 1.

As emphasized in chapter 3.2.1 the imports from the short term day ahead market get neglected. This fact is also shown in Figure 3.5.

The most important difference to model 1 is that the intersection point between the supply and subsidized demand curve (green curve in Figure 3.5) determines the new national market price (see Figure 3.5). The new national market price for electricity is below the international electricity price. Due to the fact that the Austrian electricity price (P_N) plus transmission costs (C_T) are higher than the international electricity price (P_E) no foreign supplier has incentives to buy additional electricity (L_1-L_2) from Austria. The reduced or shifted load is not exported to Europe. This fact leads to a CO_2 reduction directly in Austria.
The reduced national market price results in a gain for all customers. A_4 indicates the benefit because of price reduction for all consumers, but the reduction in supply leads to a decrease in the producer surplus.

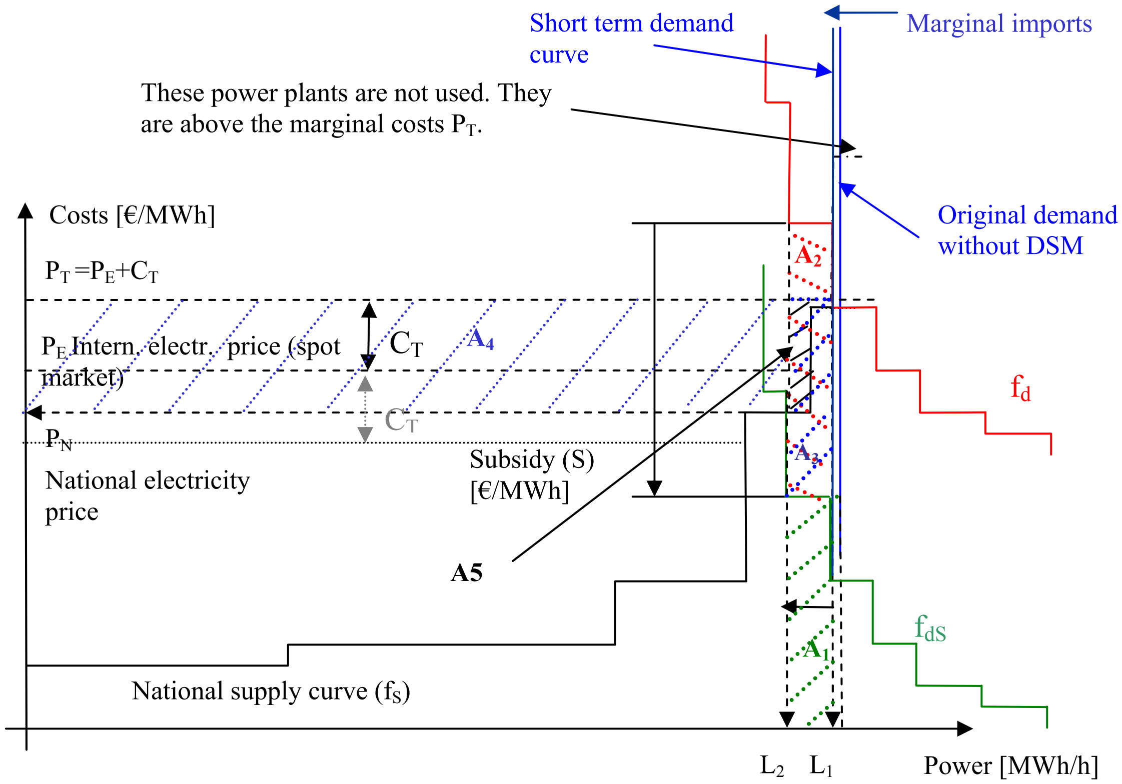

Figure 3.5: Determination of model 2 – case 2a

A_1	Costs for customers who are investing in DS-measures [€/h]
A_2	Subsidy [€/h]
A_3	„Gain“ for customers who are investing in DS-measures because of subsidies and load reduction [€/h]

A_4	„Gain" for all consumers because of national price reduction [€/h]
A_5	Loss in producer surplus because of load reduction
f_d	Elastic demand long term demand curve because of investments in DS-measures without subsidies
f_{dS}	Subsidized elastic long term demand curve
f_S	Supply curve
P_T	Total reference price $P_T=P_E+C_T$ [€/MWh]
P_N	New national wholesale price because of intersection point between supply and demand
l	Load (Power) [MWh/h]

From Figure 3.5 following economical values can be derived:

$$A_1 = \int_{L_2}^{L_1} f_{dS}(l)dl \quad \textbf{[22]} \qquad \textbf{(3.10)}$$

$$A_2 = \int_{L_2}^{L_1} [f_d(l) - f_{dS}(l)]dl \qquad \textbf{(3.11)}$$

$$A_3 = \int_{L_2}^{L_1} [P_T - f_{dS}(l)]dl \qquad \textbf{(3.12)}$$

$$A_4 = L_2 \times (P_T - P_N) \qquad \textbf{(3.13)}$$

$$A_5 = \int_{L_2}^{L_1} [P_T - f_S(l)]dl \qquad \textbf{(3.14)}$$

The calculation of A_1, A_2, A_3, A_4 and A_5 in practice is presented in chapter 6.1.4.

Depending on A_4 the consumer surplus for Austrian customers can be positive or negative:

$$\Delta CS_{Total} = A_4 - A_2 + A_3 \ldots (+ or -)! \quad \textbf{[23]} \qquad \textbf{(3.15)}$$

Due to the price reduction all customers gain A_4. The value A_4 plus the loss because of the reduction in load (A_5) results in a decrease of the producer surplus.

$$\Delta PS = -(A_4 + A_5)\ldots < 0 \qquad \textbf{(3.16)}$$

$$\begin{aligned} &National\ economic\ monetary\ gain = \\ &\Delta PS + \Delta CS = -A_2 - A_5 + A_3 \ldots < 0 \end{aligned} \qquad \textbf{(3.17)}$$

$$A_1 + A_2 = National\ economic\ expenditures\ for\ DS \ldots > 0 \qquad \textbf{(3.18)}$$

The consideration of transmission costs may result in a positive consumer surplus. The producer surplus is always negative. The negative producer surplus results in a negative national monetary gain (without any consideration of external costs). The expenditures for

[22] For a non steady step function a subdivision in steady sectors is necessary.

[23] A_4 is defined as "gain" for all consumers because of the price reduction. But, how can a customer without RTP or TOU tariffs see the actual market price and gain from the price reduction. If the price remains stable on the lower price level for a long period also the flat tariffs get corrected down. The consumers without any interest in DSM will see the benefits with a time delay if the price remains low long enough.

DS-measures are always greater than the monetary benefits from DS-measures. However, the money spent remains in Austria and reduces the load and supply and due to the reduction in national supply the CO_2 emissions are directly reduced in Austria.

If the calculated national market price (P_N) is less than P_E-C_T incentives for foreign utilities exist to buy electricity from Austria till the supply curve intersects with the price barrier P_E-C_T. That means if the national market price is cheaper than P_E-C_T the Austrian electricity price is less than the European electricity price and the foreign utilities would be interested in electricity from Austria. If the calculated national market price is less than P_E-C_T model 2 has to be modified. This modification is shown in the next chapter.

3.2.4.1 Extension of model 2 – case 2b

Regarding to model 2 - case 2a the intersection point between the supply curve and the subsidized demand curve results in the national market price P_N and the load $L_2$2a. The calculated national market price P_N is less than P_E-C_T. However, due to the incentive to export electricity the national market price raises exactly to P_E-C_T (dashed red lien in Figure 3.6).

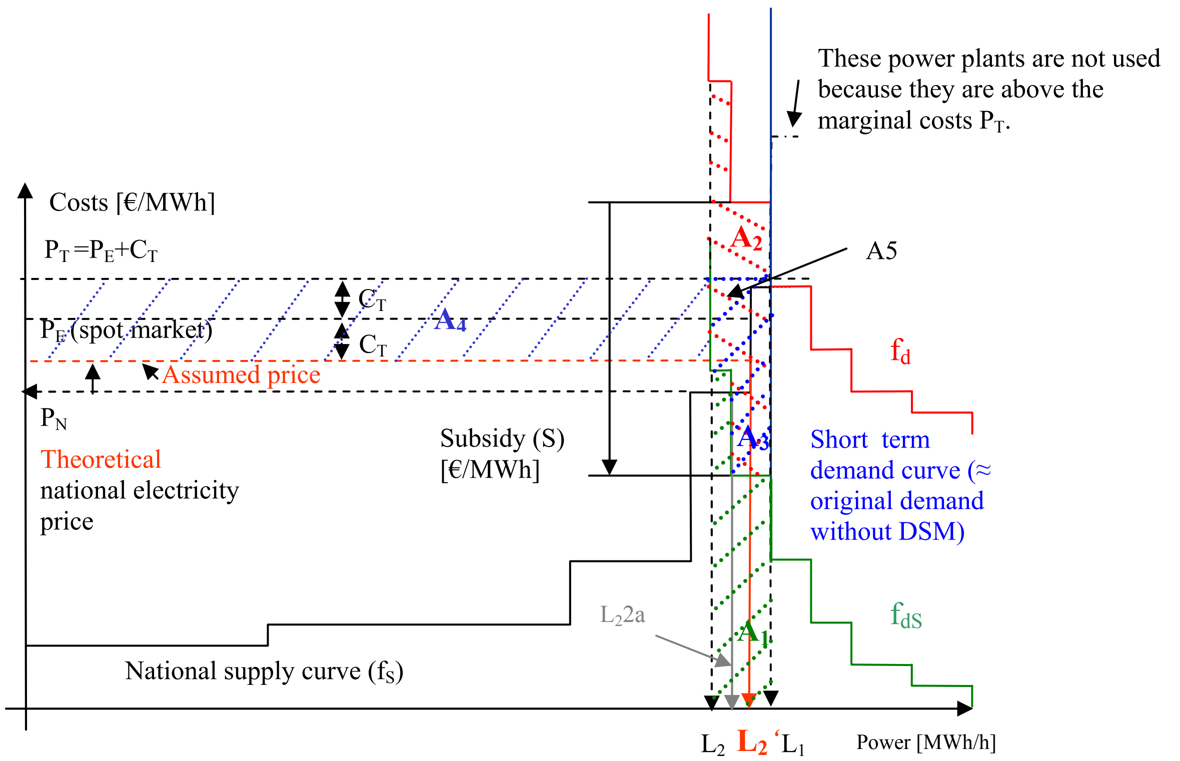

Figure 3.6: Determination of model 2 – case 2b

A_1, A_2, and A_3 are calculated in the same way as in chapter 3.2.4.

$$A_4 = L_2 \times 2C_T \tag{3.19}$$

The calculation of A_5 is approximately the same as for case 2a. Despite the sale of L_2'-L_2 to Europe due to transmission costs no major regain of A_5 takes place.

$$A_5 = \int_{L_2'}^{L_1} [P_T - f_S(l)]dl \qquad \textbf{(3.20)}$$

In contrast to model 2 – case 2a the intersection point between the assumed market price and the subsidized demand curve (green curve) determines the actual load reduction in Austria (see figure above). This intersection point leads to L_2. The assumed national market price results to a smaller A_4 compared to model 2 – case 2a. The Austrian utilities will export electricity until the intersection point between the supply curve and assumed national market price is reached. The regarding amount is labeled with L_2'. As a result of the higher national market price in model 2 – case 2b the amount L_2'-L_2 gets exported to Europe. This amount reduces the national CO_2 reduction.

The software tool "NESoDSM" developed in the course of this work is capable to switch between these two cases automatically.

3.3 Preliminary results derived from the formal framework

The intersection point between supply and demand curve (without subsidies) is always the optimum of the behavior of producers and consumers. The producer surplus <u>and</u> consumer surplus become a maximum.
„Artificial" deviation from this optimal point because of subsidies results in a debasement of at least one group. The intersection point is shifted from the optimal intersection point to a non optimal point (without consideration of external costs). As a result of this deviation the sum of the change in producer and consumer surplus is always negative ($\Delta PS+\Delta CS<0$).

For minor transmission costs ($C_T \approx 0$) a national demand reduction does not necessarily reduce the national peak electricity production. The load reduced in Austria is exported to Europe with no CO_2 reduction realized in Austria. Due to the export of the saved load and the fixed electricity price the producers make the same profit. The only benefit for customers who are using RTP or TOU tariffs is the reduction of their electricity bill as a result of their load reduction. All other customers have to pay the subsidies for the customers who are using RTP or TOU tariffs leading to a negative change in the consumer surplus.

For transmission costs greater than zero ($C_T>0$) the national market price is lower than the international market price. The electricity price decreases and as result of this decline the change in consumer surplus may be positive. The change in producer surplus is always negative. The load reduced in Austria changes directly the CO_2 emissions in Austria.

As a result of all these investigations the following preliminary results can be observed:

- <u>Natural barriers (e.g. transmission congestion or transaction costs) support a national DSM-program.</u> No money flow to Europe happens and the reduced (shifted) load in Austria reduces the Austrian supply directly.
- <u>High electricity prices support the increase of new DSM-programs.</u>

From a national point of view when transmission capacities become more and more restricted in near future (it is very expensive to invest in new grid capacities – environmental restrictions,...) national DSM will become more and more effective.

4 Empirical data

4.1 Trend of spot market prices

As emphasized in chapter 2.3.4 a high market price supports the implementation of DSM-measures in the market. Essentially for this view is the increasing gap between on-peak and off-peak prices. The higher increase in on-peak[24] prices compared to off-peak[25] prices shows impressive the increasing lack of supply capacities during peak hours (see also Figure 4.1).
Closer investigations of liberalized electricity markets showed that liberalization does not lead to problems (as in California) if only enough supply capacities exists. However, also in Europe the reserve capacities are getting short as indicated by most European spot market price trends.
This lack of capacities result in the situation that the European spot market prices get more and more volatile and the prices increase (see also chapter 4.2). Furthermore, major utilities in Europe (Edf/EnBW, E.On und RWE) have announced to close more than 10GW of supply capacity as soon as possible. Therefore, it is assumed that the wholesale prices will further increase in the future. A wholesale price forecast for on-peak hours as discussed in chapter 5.2 confirms the expectation of increasing spot market prices.

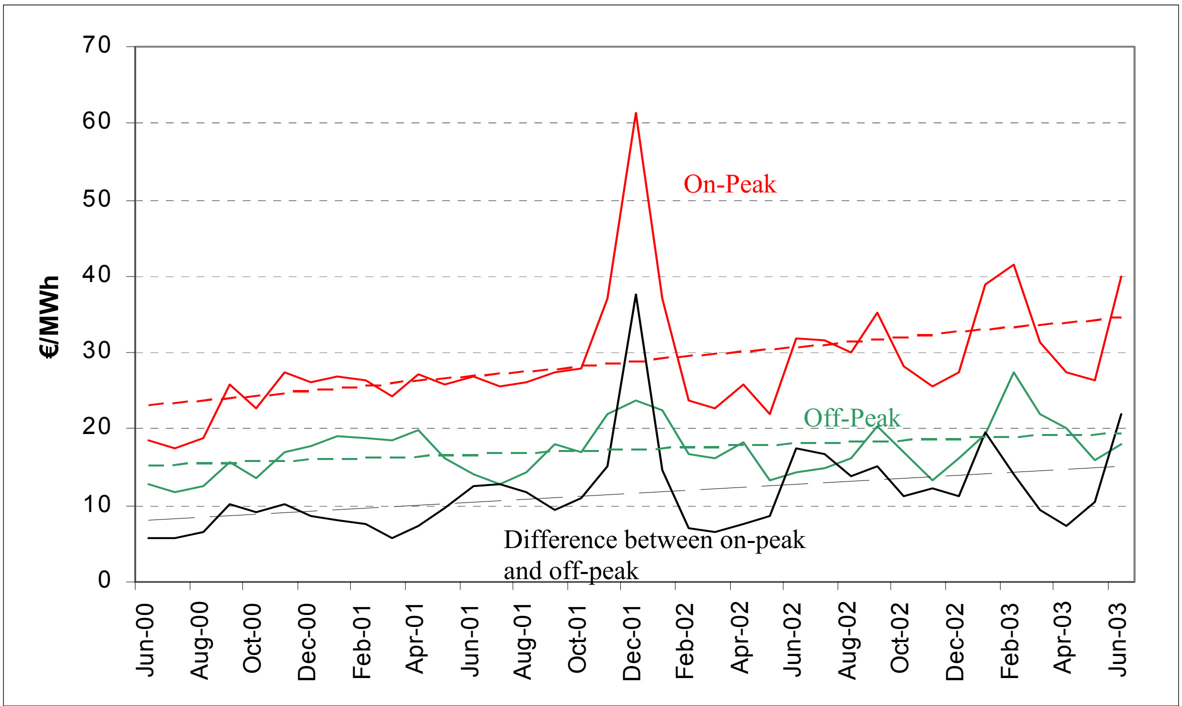

Figure 4.1: Trend of the average German spot market price (European Energy Exchange) from July 2000 to June 2003. Source: Own database

Table 4.1 shows the higher increase of average on-peak prices compared to average off-peak prices. Additionally also the increasing spread and volatility for the on-peak component can be observed.
These data confirm the expectation of increasing lack of supply (especially in on-peak hours) for the development at European electricity markets.

[24] On-peak times differ from spot market to spot market. For Germany the on-peak hours are defined from 08.00 hours to 20.00 hours.
[25] Off-peak hours for Germany: 20.00 hours to 08.00 hours.

Time period	Average off-peak prices	Spread[26] off-peak	Standard deviation (volatility) off-peak	Average on-peak prices	Spread on-peak	Standard deviation (volatility) on-peak
A: Jul00-Jun01	16.23	8.04	2.72	24.66	9.85	3.29
B: Jul01-Jun02	17.46	10.88	3.65	30.73	39.53	10.91
C: Jul02-Jun03	18.39	12.63	3.80	32.02	15.91	5.60
Increase A to B	1.23	2.84	0.93	6.07	29.68	7.62
Increase A to C	2.16	4.59	1.08	7.36	6.06	2.31

Table 4.1: Determination of characteristically price band values for the European Energy Exchange (EEX) in Leipzig from July 2000 to June 2003

4.2 Spot market database

4.2.1 General point of view

To get an overview about the European supply situation and the prices a database for spot market and future/forward prices was designed. The database was set up in Excel and can be updated easily and automatically with new data.

The database includes following countries:
- Germany: European Energy Exchange (EEX) in Leipzig
- Austria: Energy Exchange Austria (EXAA)
- England & Wales: Electricity Pool till February 2001, Automated Power Exchange (APX) from March 2001
- Spain: Electricity Pool managed by OMEL
- Denmark, Finland, Sweden and Norway: Nordpool (Elspot system price)
- Netherlands: Amsterdam Power Exchange (APX)

For each market following data are shown:
- Average monthly prices for on-peak/off-peak times or average values for base[27] times.
- Day courses for working days to show characteristic peaks during a day
- Overview of all markets

To illustrate the increasing prices in Europe some examples will be shown. All figures indicate the same situation: Raising prices (especially during peak hours[28]) and increasing price volatility in all[29] European spot markets.

[26] The fluctuation is defined as the difference between the maximum and minimum value.
[27] The base values include all hours of a day. In contrast the on-peak values include only the hours 07.00 to 19.00, e.g. for England and Wales. The off-peak hours are defined from 19.00 hours to 07.00 hours, e.g. for England and Wales.
[28] In this context the term peak hours is equivalent to the term on-peak hours.
[29] It has to be pointed out that there exists an exception. At the beginning of 2001 the electricity pool in England and Wales was restructured. Since this revision of the market the prices have been dropping steadily.

4.2.2 Germany

Figure 4.2 and Figure 4.3 illustrate the steadily increasing prices. Beginning with the year 2000, each following year has a higher price level as the year before.

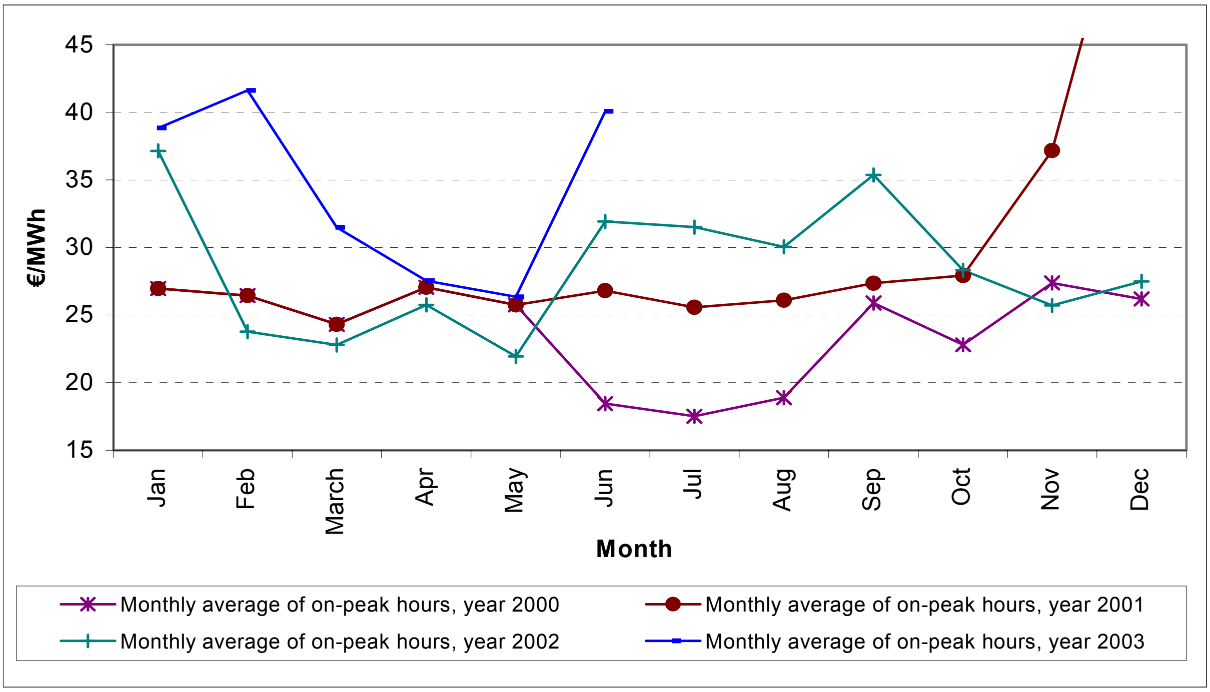

Figure 4.2: Trend of the monthly average EEX on-peak prices from May 2000 to June 2003. Source: Own database

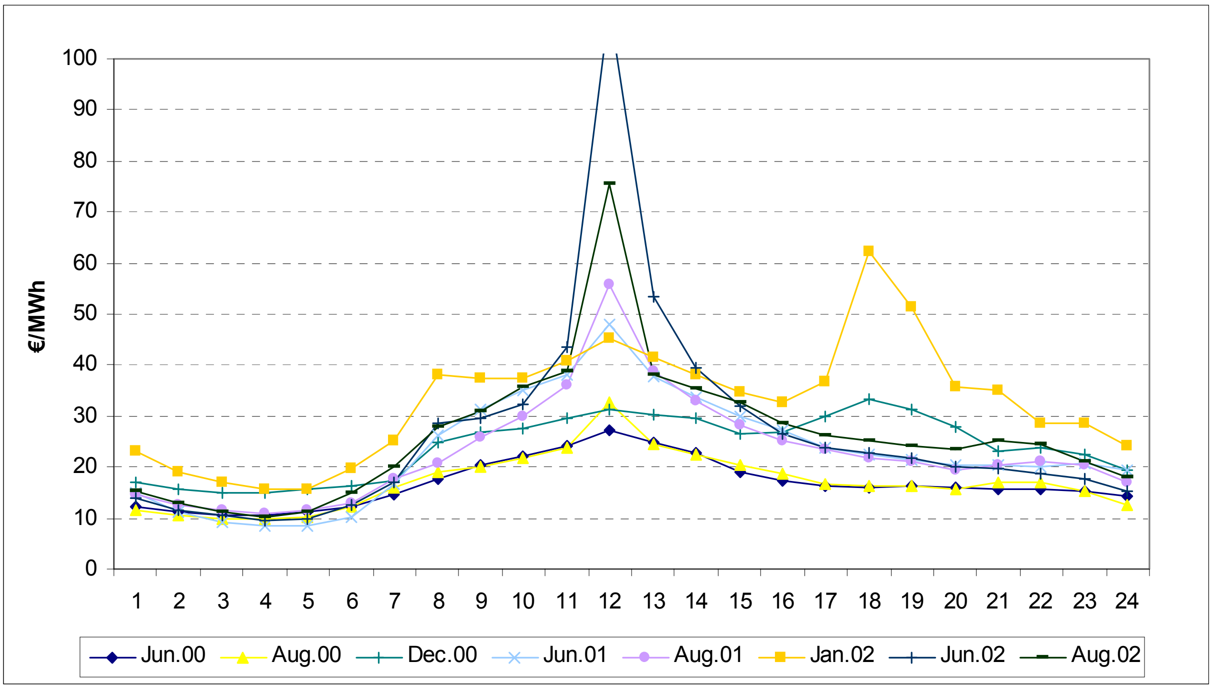

Figure 4.3: Examples for price curves[30] of the European Energy Exchange (EEX) in Leipzig for working days. Source: Own database

[30] Normally, more than one product is traded on a spot market. For example: Block market for on-peak hours or off-peak hours and the hourly market. The above shown daily curves for the EEX are based on the hourly market for working days.

Because of high electricity consumption during winter months[31] the most critical months during a year, regarding to lacks in supply, are winter months[32]. Two very important daily winter peaks[33] exist. One peak occurs at 12.00 hours and the other peak at 18.00 hours. Normally, the 18.00 hours peak is the higher peak in winter months. In Austria this 18.00 hours peak defines the yearly peak. Therefore, a prognosis for the yearly peak till 2010 is based on the 18.00 hours peak (see also chapter 5.1.2.2).

4.2.3 Austria

The Energy Exchange Austria (EXAA) has launched in March 2002 and since them prices and volatility have been raising steadily.

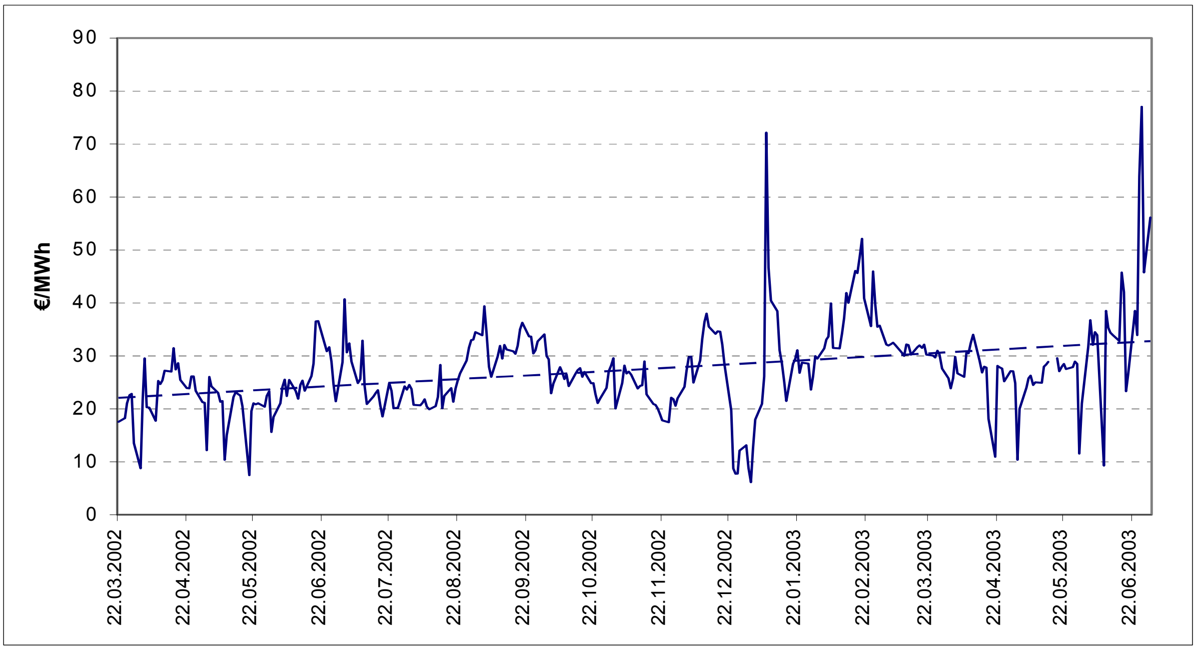

Figure 4.4: Spot market price trend for working days[34] at EXAA

4.2.4 Spain

In Spain the share of hydro power plants is about 38% of total installed capacity. Despite this large share the produced energy from hydro power plants is only in the range of 21% of the total produced energy during a year. The energy production from hydro power plants is restricted by the yearly rainfalls and therefore very volatile. Because of the large share of installed hydro power plants and the sparse rainfalls of the last years the supply from hydro plants decreases. The rainfalls in the first quarter of 2000 were only 5% of the average value. Due to this lack in production and increasing demand the wholesale prices have been increasing continuously.
However, the transmission capacities to Portugal and France are very restricted because Spain is based in an autarkic electricity system.

[31] In this context winter months are November, December and January.
[32] Because of sparse rainfalls in the summer 2003 similar lacks in supply occurred for July and August.
[33] In this context price and load peaks are equal. If the supply is restricted (especially during winter months) and the load peak approaches the reserve capacity, load peaks lead to price spikes.
[34] Monday to Friday

Because of these problems Spain has started very early in history with the integration of Demand-Side-Management methods in the system (for example Red Eléctrica (REE), see also /35/).

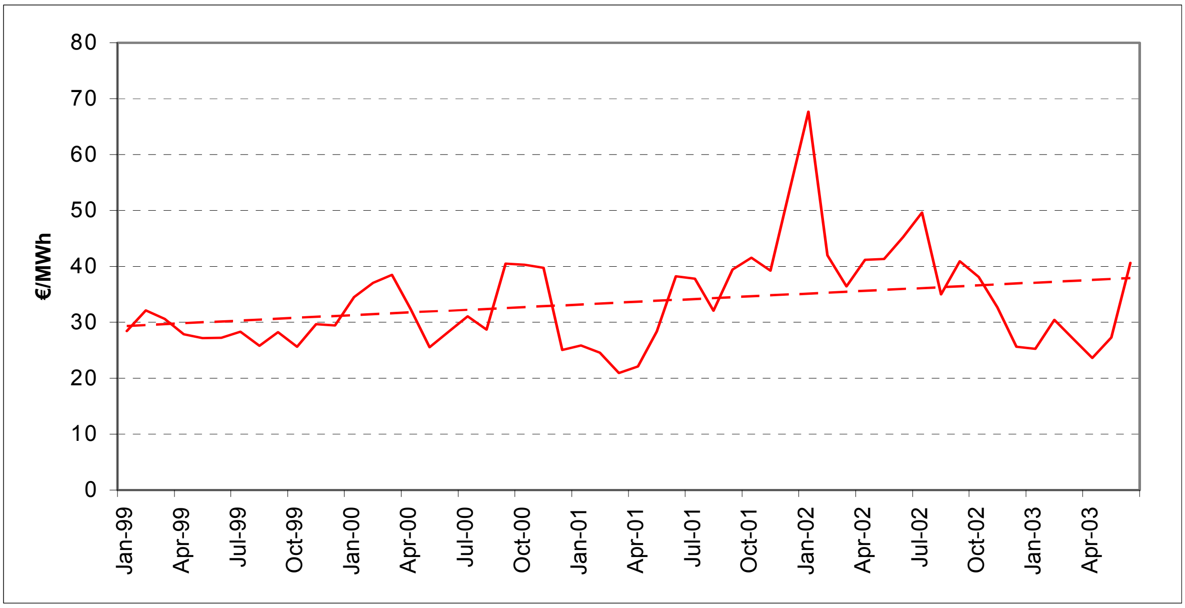

Figure 4.5: Average monthly final spot market prices[35] for Spain from January 1999 to June 2003

4.2.5 Netherlands

Compared to the other European markets the Amsterdam Power Exchange (APX) is distinguished by a different market system.

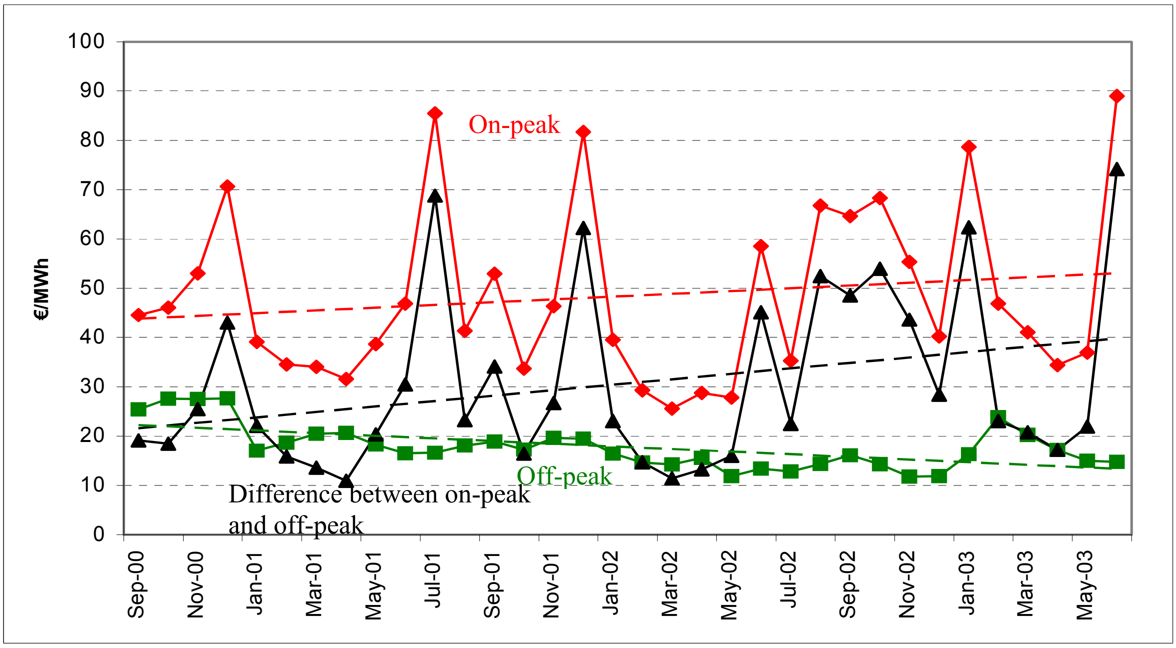

Figure 4.6: Trend of the Amsterdam Power Exchange (APX) on-peak[36] and off-peak[37] prices from September 2000 to June 2003

[35] For all days a week

The market price includes also the price for transmission congestion. In the Netherlands transmission congestion occur very frequently and therefore the prices are mostly higher than in other European countries.

4.2.6 Comparison between the German and Austrian market price

Without any transmission limitation between these two countries the two market prices should converge to the same price. Transmission of electricity is mainly limited by two factors:

- The available transmission capacities and
- The transaction costs of the transmission: Each transaction is accompanied with unpleasant activities and time. Therefore, a monetary threshold for transactions exists.

The comparison between the Austrian and German spot market prices leads to the average transmission and transaction costs between these two countries which can be observed from Figure 4.7.

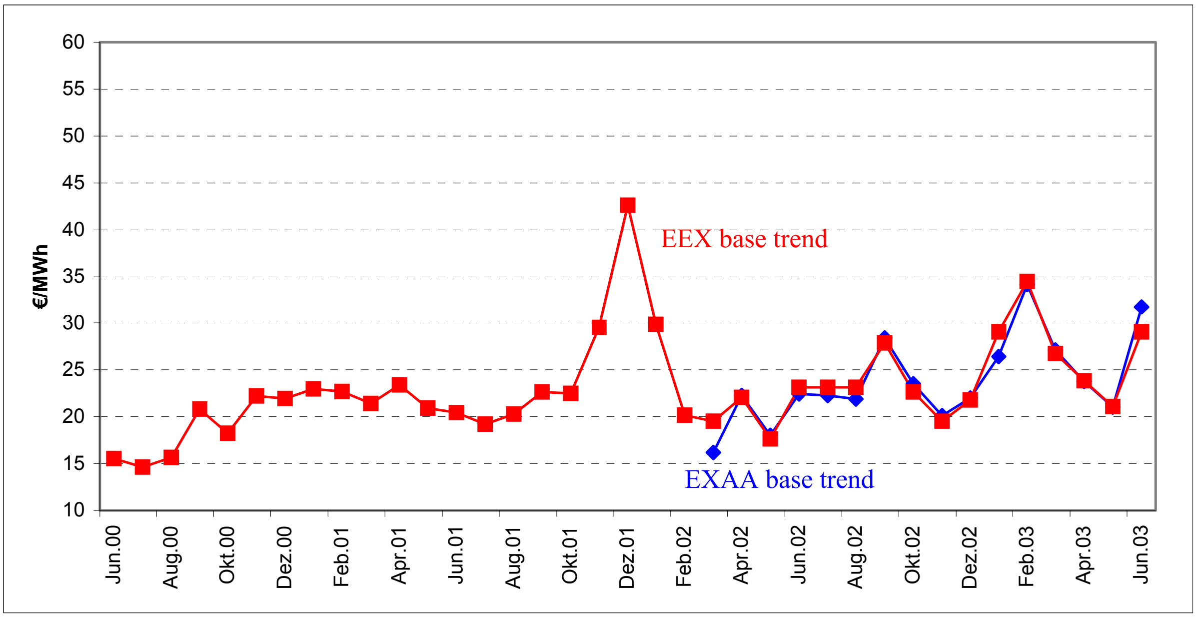

Figure 4.7: Comparison between the Austrian (EXAA) and German (EEX) spot market price for base hours[38]. Source: Own database

The comparison between the two market prices for more than one year leads to average transmission and transaction cost of 0.73€/MWh. Currently, extraordinary congestions between Austria and Germany are sparse and therefore the calculated value of 0.73€/MWh indicates mainly the constant European Transmission System Operators (ETSO) fee[39].

[36] On-peak: 07.00 hours to 23.00 hours
[37] Off-peak: 23.00 hours to 07.00 hours
[38] Base hours: 00.00 hours to 24.00 hours
[39] An order decided by the Austrian "Elektrizitäts-Control-Kommission" in April 2002 determines a "Cross-Border-Tarification" of 1€/MWh for each cross border electricity transmission (ETSO CBT mechanisms). Source: www.e-control.at

4.3 International experiences with dynamic tariffs[40]

4.3.1 General point of view

The basic idea for dynamic tariffs is to give consumers the possibility to react to price signals.

In principle two different dynamic tariffs exist:

- Real Time pricing (RTP) and
- Time-of-Use tariffs (TOU tariffs)

The real time pricing uses the actual hourly wholesale or spot market price as basis for the price signal. This is a very detailed and expensive approach (see also chapter 4.3.3). Therefore, at the moment real time pricing is only used for the industry sector.
The TOU tariff uses predefined high price and low price areas derived from historical spot market prices, but it does not reflect the actual spot market price. It reflects merely the expectation of the price development because of historical trends. Therefore, Time-of-Use tariffs are mainly used in the household and commercial sector. Detailed information on this topic can be found in /35/: *„Die Bedeutung von dynamischen Tarifmodellen und neuer Ansätzer des Demand-Side-Managements als Ergänzung zu Hedging-Maßnahmen in deregulierten Elektrizitätsmärkten“.*

This price information gives consumers the possibility to shift on-peak load to off-peak periods. If danger in lack of supply is given dynamic tariffs are a perfect and cheap solution to solve this problem. Hence, dynamic tariffs create an elastic demand curve. To give incentives to the utilities to build new power plants the dynamic tariffs should reflect the long term marginal costs during on-peak hours and the short term marginal costs during off-peak hours.
For a well working spot market it can be assumed that this price always reflects the marginal costs. Therefore, the ratio between the maximum tariff and the minimum tariff for a Time-of-Use tariff reflects the ratio between on-peak and off-peak price of the reference market. Because of the expected shortages in supply during peak hours in the future the on-peak prices will reflect more and more the long term marginal costs of supply.

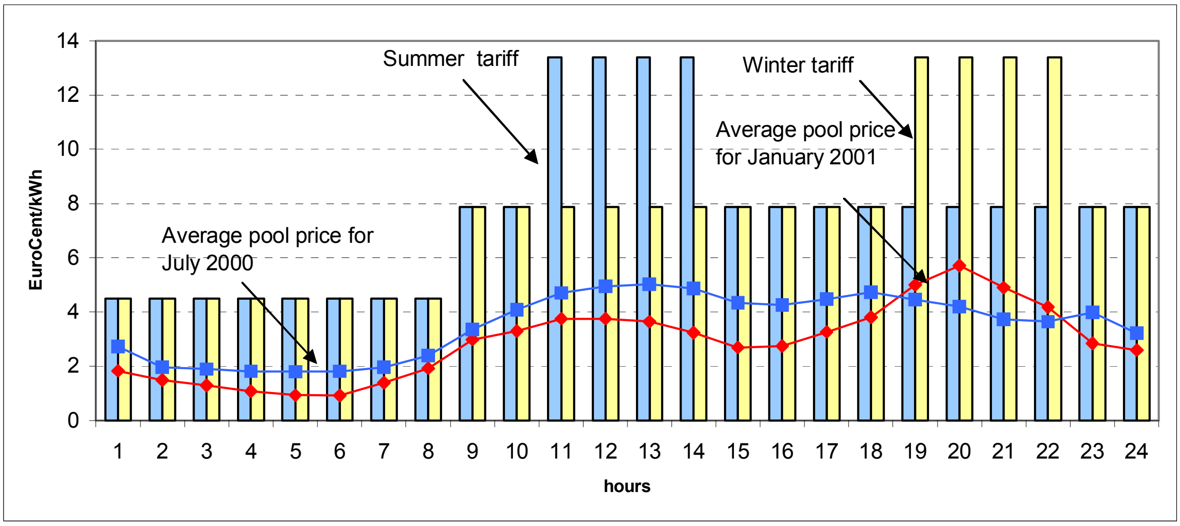

Figure 4.8: Triple Tarifa zone A (Madrid) from Iberdrola[41]

[40] Real Time Pricing and Time-of-Use Tariffs
[41] The tariffs do not include taxes and other charges (Standing Charge). The tariffs are valid for „Baja Tensión“ (= low voltage level).

Based on these results the following equation can be assumed:

$$\left(\frac{p_{\max}}{p_{\min}}\right)_{Spot\ market} \approx \left(\frac{p_{\max}}{p_{\min}}\right)_{Tariff} \quad \textbf{(4.1)}$$

The verification of (4.1) can be taken from /35/.

Additionally, also international information about Time-of-Use tariffs were collected (see also /35/):

- Great Britain: 24 different Time-of-Use tariffs for commercial and households from Yorkshire Electricity und London Electricity.
- Norway
- Spain
- British Columbia
- Australia

Tariff[42]	Period	Number of different price levels	P_{max}/p_{min}
Yorkshire, for business-region Yorkshire	December, January	4	3.71
	November, February	4	2.95
	March - October	1	1.00
	Weekends	2	1.16
London Electricity, for business	December, January	4	5.00
	November, February	4	3.30
	March	3	1.41
	April - October	2	1.16
	Weekends	2	1.16
Economy 7 tariff of London Electricity for business	Whole year	2	2.12
Evening & Weekend rate for business from London Electricity	Working days	2	2.12
	Weekends	1	1.00
Economy 7 tariff from London Electricity for region London, first 1,500kWh consumption per quarter	Whole year	2	2.34

Table 4.2: Examples for TOU tariffs in Great Britain

4.3.2 Achieved load shifting during on-peak hours

A lot of experiments with dynamic tariffs took place in the past. Most of the TOU experiments happened in the residential sector. Most of the Real-Time-Pricing investigations were carried out in the industry and commercial sector. For more details see /16/.

The creation of the short term demand curve in chapter 4.5 requires the average load size for each sector (household, commercial and industry). For this determination an average customer size (at least the load value at the 18.00 hours peak) is necessary. But, what is the average electricity consumption and average peak value for a company?[43]

[42] All tariff data without Value Added Taxes (VAT).

[43] In principle a second approach exists to solve the problem with standardized load profiles for commercial an industry customers. It is possible to disaggregate the power consumption for the critical time at 18.00 hours in

The different load profiles for households are similar and due to the resemblance standardized load profiles for the household sector do exist. Because of standardized load profiles and the expectation of major load shift potentials in the residential sector an average load shift curve for the household sector is created (see also Figure 4.9). Furthermore, no short term demand curve is considered in the model in this work (see also 2.3.2) and therefore only the residential short term demand curve is shown as an example. The average load shift curve was determined from Table 4.3 for German[44] household samples only[45].

Type	Name of study	Country	Details	P_{max}/p_{min}	Load reduction [%]
TOU	Saarland-zvlST	D	Households	2.18	6.50
TOU	Saarland-SESAM	D	Households[46]	2.18	8.70
TOU	BEWAG-T1	D	240 samples. Only households with more than 1,500kWh electricity consumption per year[47]	2.94	7.00
TOU	BEWAG-T2	D		3.82	9.00
TOU	Stw. München	D		1.88	1.20
TOU	ESW Wiebaden	D	1,300 households[48]	3.00	2.32
TOU	Imatra: w-sh HH-passive	FIN		9.26	10.00
TOU	NMPC	US		3.06	1.00
RTP	Paderborn	D	Industry	11.67	13.40
RTP	Eckernförde	D	1,000 households	6.00	11.54
RTP	NMPC	US	Industry	4.15	13.20
RTP	NMPC	US	Industry	2.78	3.90
RTP	SCE	US	Industry	2.89	2.00
RTP	PG&E: 1995	US	Industry	35.50	12.00

Table 4.3: Historical experiments with dynamic tariffs and achieved load shifting

The average load shift is characterized by a logarithmic function. Small numbers of p_{max}/p_{min} leads to relative large reductions in demand. If the price increases more and more the increase in reduction obtained is only moderate.

From Table 4.3 the average load reduction depending on p_{max}/p_{min} can be determined:

$$Load\ reduction = 3.87 \times \ln(\frac{p_{\max}}{p_{\min}}) + 4.08 \quad [\%] \tag{4.2}$$

Very problematic seems the few numbers of samples available for the derivation of the regression equation (see Figure 4.9).

winter months. With this disaggregated approach a percent share for the power consumption of each sector is obtained. Currently, the most disaggregated investigations are based on the yearly energy consumption, but the yearly energy consumption does not say much about the power consumption at a certain hour. Such a disaggregated investigation is planned for the near future to complete the short term demand curve by the commercial and industry sector. For a disaggregated investigation based on the power consumption for each sector see /40/.

[44] To eliminate different behavior in different countries only the German samples were used.

[45] Only for the German household samples with a load reduction greater than p_{max}/p_{min}.

[46] The household group "SESAM" was identified by the additional possibility to read the actual bill online. The "zvlSt" group could not read the actual bill online. The "zvlSt" household group got the bill at the end of a certain period (see also /3/)

[47] Because of the chosen sample 63% of all BEWAG household customers were represented (see also /42/).

[48] For more details see /11/.

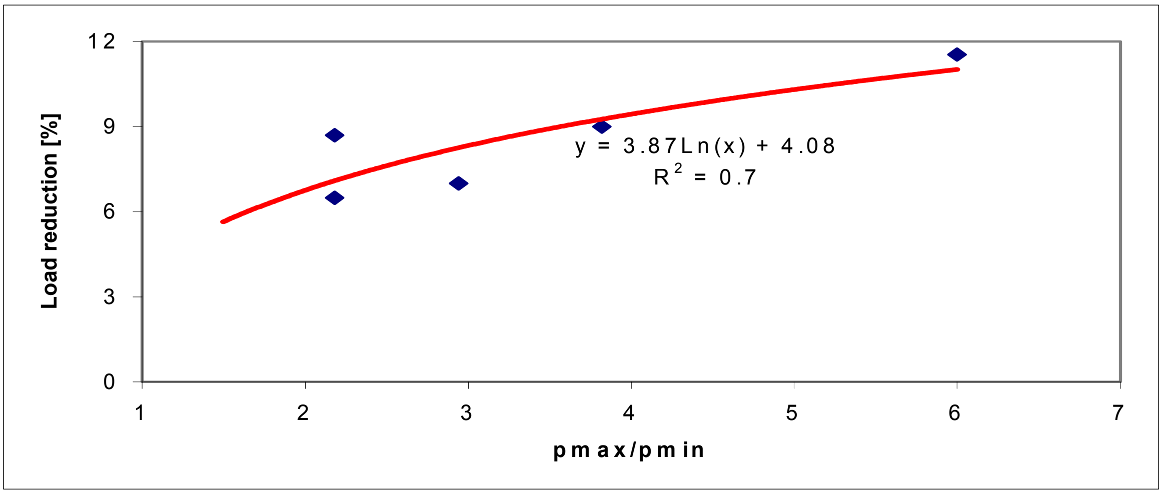

Figure 4.9: Average load shifting for the household sector derived from historical experiments. Source: Own calculation

4.3.3 Expected future development of dynamic tariffs

Historically, Real-Time-Pricing (RTP) was linked to the commercial and industrial sector only. Because of missing technologies (Internet, e-commerce) the implementation of the RTP was very expensive in the past.
Due to the expected developments in e-commerce and internet technologies a drop in prices for these technologies seem very realistically. RTP can be used in the residential sector. Washing machines, driers, dish washers, refrigerators, freezers, and heating systems will be linked via internet to the supplier and the customer can get the information about the actual electricity price (or tariff). Depending on the system used the household appliances can be switched off by the customer or automatically by the supplier. The concept of "smart homes" will be used. It is assumed that 20% of all household, business and public customers will implement RTP in the future.

Most of the investigations made in the residential sector were based on TOU-tariffs. But, the incentive to react to price signals is assumed to be equal for a TOU-tariff and for RTP. Therefore, the derived average load reduction, based on (4.2) which is mainly based on TOU-tariffs, can be used for the load reduction based on RTP.

4.4 Structural parameters for different consumer clusters in Austria

4.4.1 Definition of structural parameters

In the following three structural parameters are defined to classify the different customers in a three dimensional coordinate system. These three structural parameters are:

- Electricity consumption
- Load factor
- Load Volatility

- Electricity consumption:
  The easiest way to differentiate between customers is to use the daily consumed electricity in kWh.

- Load factor:
  The problem with the used electricity during a day is that no information about the load shape is given. What is the maximum power used a day? For a supplier the maximal consumed power during a day is very important. Therefore, in the following the load factor (L) is defined:

$$L = \frac{electricity}{power_{\max}} \tag{4.3}$$

L	load factor [h]
electricity	consumed electricity during a day [kWh]
$power_{max}$	maximal load during a day [kW]

- Load volatility:
  The load factor does not say anything about the frequency and the magnitude of the load spikes during a day. Therefore, the volatility is defined as the standard deviation of the hourly power based on an average value of zero.

$$s = \sqrt{\frac{1}{n-1}\sum_{i=1}^{n}\left(\frac{x_{i+1}-x_i}{x_i}\right)^2} \times 100\% \tag{4.4}$$

s	standard deviation [%]	n	number of hours (=24)
x_i	power in hour i	x_{i+1}	power in hour i+1

A detailed description can be gathered from /35/, *ÖNB-Jubiläumsfonds-Projektes Nr. 7895.*

4.4.2 Classification of different consumer clusters

Depending on the business the load shapes for commercial and industry are not fixed to a certain cube. All three structural parameters change depending on the size and undertaken business. The only sector which is linked to a certain cube is the residential sector. Without the consideration of electrical heating[49] the residential sector is always located in costumer group 6 (CG 6). The volatility is always higher than 20%, the load factor always higher than 12h and the electricity consumption always less than 30kWh a day.

Because of the already mentioned importance (see also chapter4.3.2) of the household sector a closer look to this sector is given.

[49] In Norway electrical heating systems are very common. Therefore, in Norway households are located in CG 1.

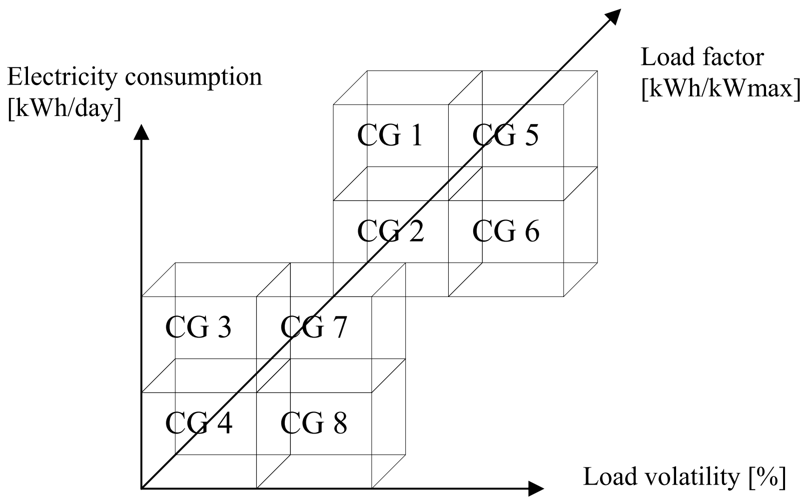

Figure 4.10: Classification of different consumer clusters

4.4.3 Residential sector[50]

In this work the standardized VDEW load shapes are also used in Austria. The VDEW load shapes are standardize to a yearly electricity consumption of 1,000kWh. To get the actual load shape the standardized load shapes have to be multiplied with K_H.

$$K_H = \frac{Yearly\,electricity\,consumption\,[kWh]}{1{,}000kWh} \quad \textbf{(4.5)}$$

There exists a standardized load shape for summer, winter and spring/autumn months. For each period shapes for working days, Saturdays and Sundays are given. The VDEW load shapes are defined for eleven different customer groups (mainly households, commercial, and agriculture). For the commercial sector seven different sub classes (G0 to G7), and for the agriculture sector three sub classes (L0 to L2) exist.

After multiplying the standardized load shape with K_H the residential sector load shape has to be multiplied with a polynomial 4th order to incorporate the change in the electricity consumption for light bulbs at the frontier of the three different shapes (winter, summer, and spring/autumn).[51]

Now the definition of an average household customer is necessary. The yearly electricity consumption of the residential sector with electrical heating is 13TWh[52]. The average consumption for electrical heating is in the range of 3TWh/year[53]. Division of the net electricity consumption of 10TWh by 3.32 million households[54] in Austria leads to 3,012kWh. Most of the Austrian utilities specify 3,500kWh as an average consumption.

[50] Without consideration of electrical heating systems.
[51] This procedure is only necessary for residential load shapes.
[52] The exact number for 1999 was 12.8TWh. Source: Betriebsstatistik 1999.
[53] See also /7/
[54] Source: Statistik Austria, www.statistik.at

Therefore, the average electricity consumption for an Austrian household is set to 3,500kWh/year.

With all these calculations a standard customer load shape for the residential sector with a yearly electricity consumption of 3,500kWh can be derived as shown in Figure 4.11.

The peak consumption for an average household is 800W in winter months. This value does not include the power used for electrical heating systems.

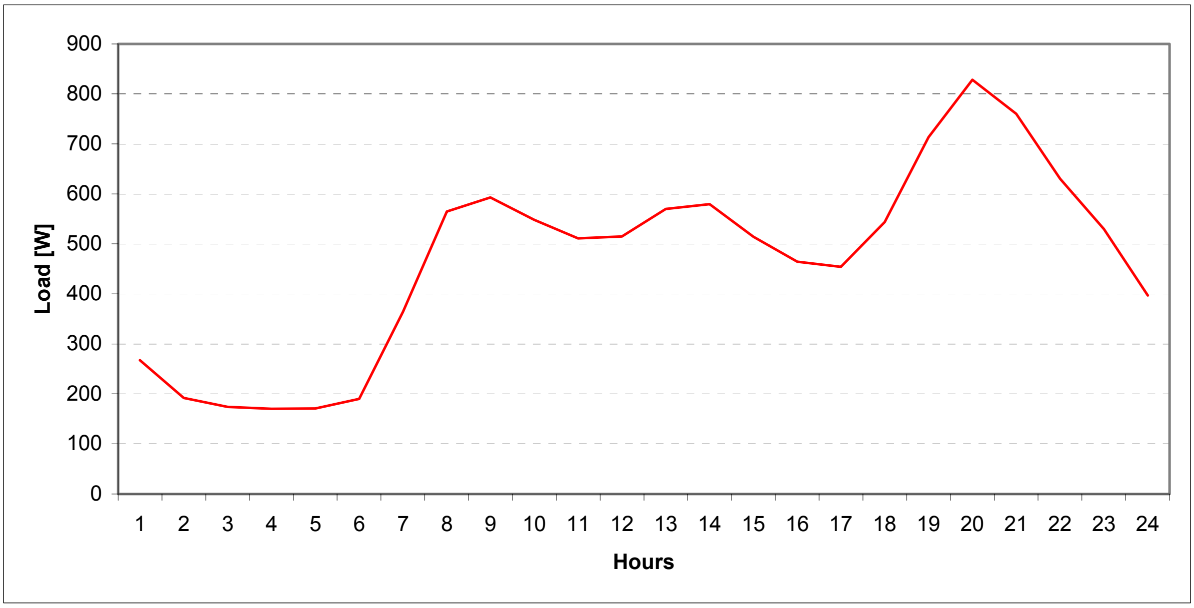

Figure 4.11: Standardized residential customer in Austria, without consideration of electrical heating and without DSM

4.5 Aggregated short term demand curve for the residential sector[55]

As emphasized in chapter 4.3.3 the future development of new e-commerce technologies will lead to a drop in costs for Real-Time-Pricing. Therefore, it is assumed that approximately 20% of all Austrian customers will use Real-Time-Pricing in the future. From investigations it is known that currently[56] approximately 20% of all household and business costumers in England & Wales use Time-of-Use tariffs (see also /35/). Therefore, the assumed 20% for the costumers who will use Real-Time-Pricing seems realistically.

In Figure 4.12 an aggregated demand curve for 20% of all Austrian average households for the 800W peak during winter months is shown. The average load shift derived from historical investigations is defined by the following equation (see also chapter 4.3.2):

[55] If the price remains on a high level for a long period the consumers will invest in DSM-measures to regain the loss in service. For example: If only once a year a very high price level occurs most of the consumers will shift the washing machine load from the high price level period. But, if the high price level remains on the high price for e.g. one month or occurs 30 times a year the consumers will invest in high efficiency devices. Note, the short term demand curve is mainly characterized by loss of service (in on-peak hours) to decrease the electricity consumption during high price levels.
[56] 2002

$$Load\ reduction = 3.87 \times \ln(\frac{p_{\max}}{p_{\min}}) + 4.08 \quad [\%] \qquad \textbf{(4.6)}$$

p_{max} maximal charged tariff during a day
p_{min} minimal charged tariff during a day

For the calculation of the demand depending on p_{max}/p_{min} a basic p_{min} has to be assumed. Because of (4.1) the off-peak spot market prices can be directly used instead of the off-peak tariff.
From the spot market database the average off-peak price is known. The future Austrian off-peak price is assumed to be 20€/MWh. This value is slightly higher than the average value of 17.23€/MWh[57] for the last 3 years. As emphasized in chapter 4.1 the off-peak prices will not increase in the same dimension as the on-peak prices. For some market places the average off-peak price is remaining constant (e.g. Netherlands). Therefore, only a slight increase for the off-peak price from 17.23€/MWh to 20€/MWh is considered.

With these assumptions and (4.6) the demand reduction for 664,000 average households depending on p_{max}/p_{min} for winter peak times can be calculated.

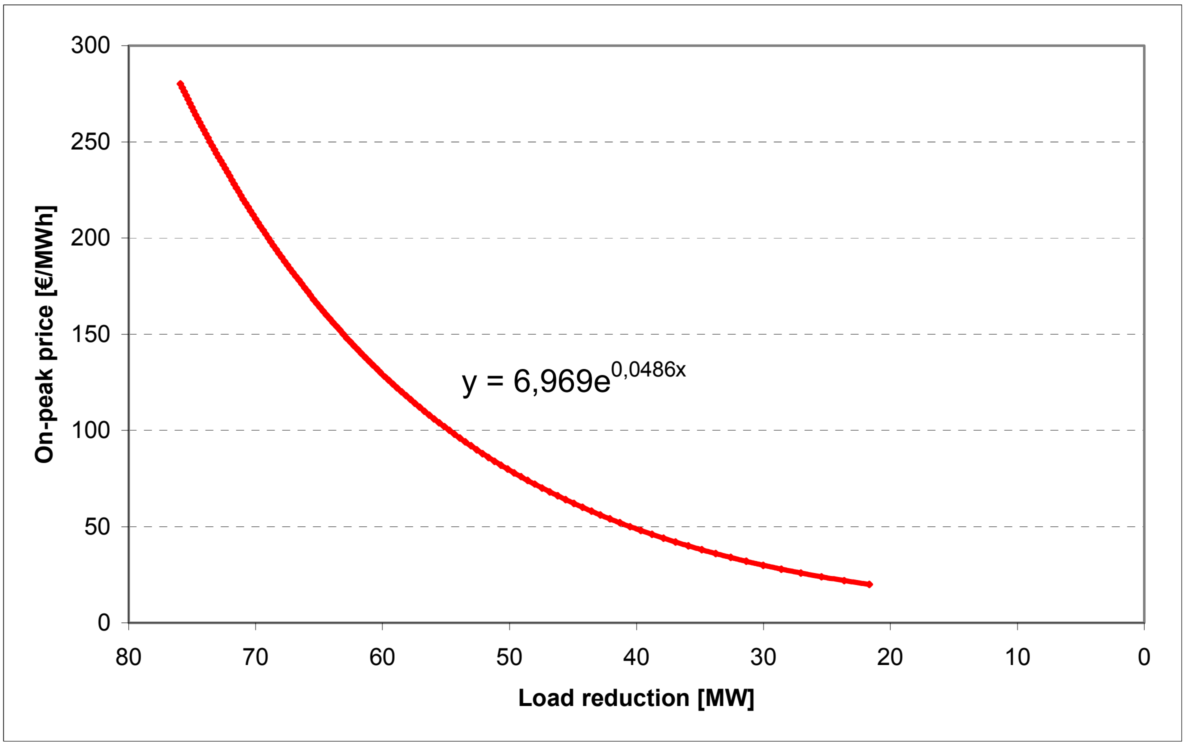

Figure 4.12: Aggregated short term demand reduction because of load shifting for 664,000 Austrian households during peak times (18.00 hours) in winter months

Because of loss in service the short term demand curve is very steep and the possible load reduction is rapidly limited (see Figure above).

[57] Average EEX off-peak price.

4.6 Structure of demand during winter months

4.6.1 General point of view

For the development of the long term demand curve it is necessary to know the theoretical and feasible reduction potential of the most energy intensive and inefficient applications. Therefore, it is necessary to identify applications with a high power demand and high theoretical reduction potential during on-peak hours in winter months.

In this context, five applications have been defined:

- Low temperature: Energy used for low temperature heating and water heating
- Process heat: for Electrical cooking, laundry, drying, dish-washing, and ironing.
- Stationary motors: Freezers, refrigerators and pumps
- Other motors and
- Light/EDP: TV, light bulbs, personal computer, and other minor devices.

All figures shown in this chapter are gathered from /40/: *VEO, Forschungsgemeinschaft der EVU – EFG, EFG – Projekt – Nr.: 4.12:* „Aufschlüsselung der Lastganglinien nach Endenergie-Anwendungen 1995“*, Forschungsprojekt im Rahmen des IRP-Save Projekts für Österreich, Graz, August 1997, Ausfertigung F.*

4.6.2 Aggregated demand for the industry sector

The industry sector has the biggest electricity demand in Austria. Approximately 36% of total electricity consumed per year is used by the industry sector. The aggregated load shape for all winter months is very homogenous and no marked evening spike can be observed. The total load at 18.00 hours is 2.47GW and is lower than the noon peak. 77% of the total load at 18.00 hours is contributed by stationary electrical motors with high efficiency. These stationary motors are components of the working process and therefore difficult to remove or improve. In order to increase the energy efficiency the whole manufacturing process has to be changed. This is not an easy and cheap task. In other words the industry sector may not react to price signals quickly with low costs.
The Light/EDP potential is minor compared to the commercial sector. Furthermore, during a day the Light/EDP part is very homogenous and therefore, it is assumed that they are a part of the manufacturing process, which is not easy to change.
Companies with huge electricity consumptions tend to be more interested in electricity bill reduction than small companies from the commercial sector. Therefore, it is assumed that most of the energy efficiency increasing measures have been already achieved.

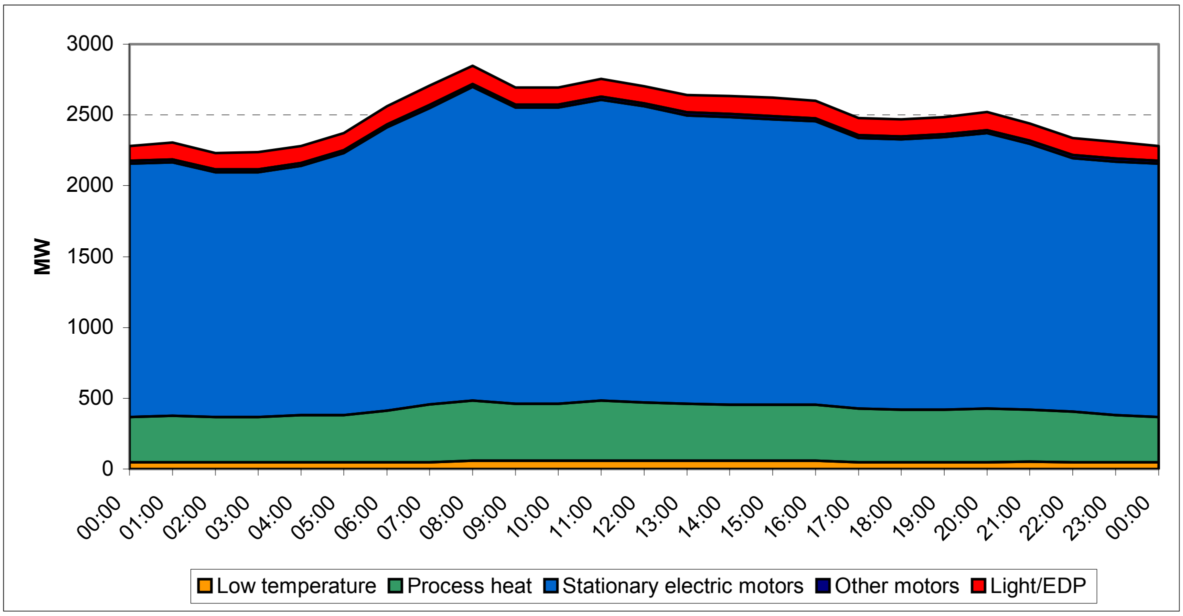

Figure 4.13: Aggregated load shape for the industry sector for January 18, 1995. Source: /40/

As a result of all these reflections no reduction potential for the industry sector is considered in this work.

4.6.3 Aggregated demand for the commercial sector

The following sectors have been considered in the aggregated load shape as shown in Figure 4.14:

- Joinery
- Locksmith's shop
- Car dealer
- Laundry
- Truck farm
- Bakery
- Printing office
- Butcher's shop
- Hairdresser
- Restaurants
- Hotels
- Trade
- Tourist trade
- Office
- Banks

As a result of the variety of considered sectors a major reduction potential in the commercial sector is expected. Especially, the light/EDP part is very promising. 36% of the evening peak at 18.00 hours is caused by light/EDP appliances. The cheapest and fastest reaction to price signals is expected for the light/EDP appliances. Regarding to stationary motors the same considerations are applied than for the industry sector (see chapter above). No cheap and fast reaction to price signals is expected for stationary motor appliances.

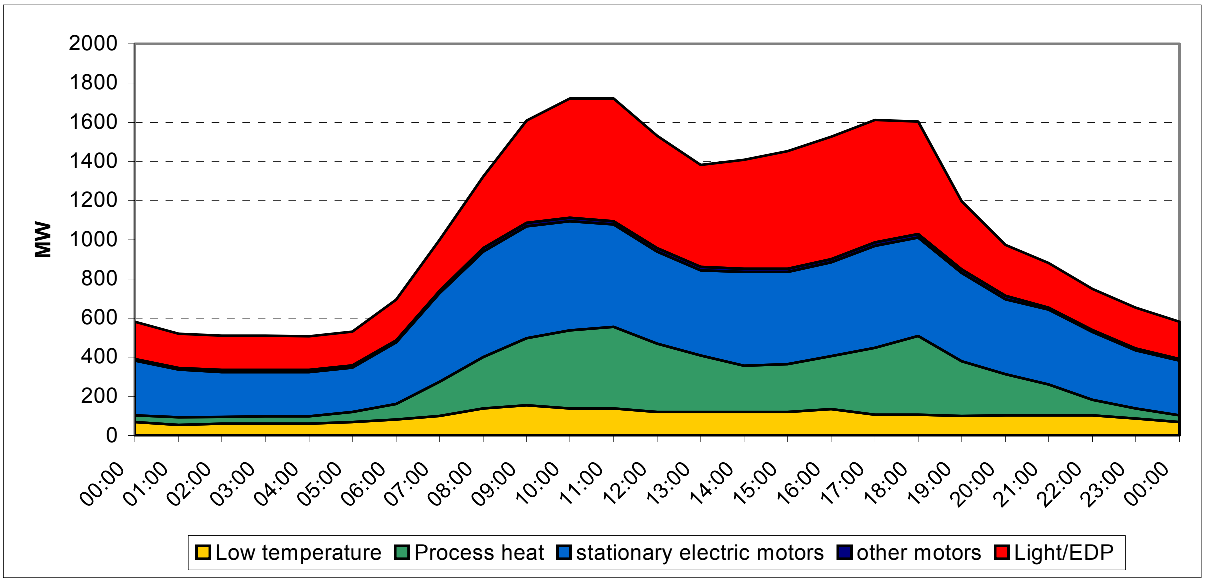

Figure 4.14: Aggregated load shape for the commercial sector for January 18, 1995. Source: /40/

For the heat appliances process no detailed information about the used appliances are available. Only the aggregated load for all appliances is available, therefore no estimation about the reduction potential for each appliance is possible. It is important to split the 573.91MW consumed by all light/EDP appliances at 18.00 hours into light appliances and EDP appliances. In Austria approximately 850,000[58] persons in the commercial sector use a personal computer at work. Assuming an average consumption of a PC with 200W and that the majority of the employees are still at work at 18.00 hours a load of 170MW for EDP appliances can be determined. As a result of the 170MW EDP load 403.91MW remain for light bulbs.

4.6.4 Aggregated demand for the public sector

Just as for the commercial sector the light/EDP appliances are the most power intensive applications with power demand at 18.00 hours of 518.52MW. With the assumption that 55% of all employees[59] in the public sector use personal computers the EDP load consists of 89.43MW. As a result of the 89.43MW electronic data processing load 429.09MW load remains for light bulbs.

[58]Year 2000, source: www.statistik.at.
[59] Estimated 813,000 employees in the public sector in 2000. Source: www.statistik.at.

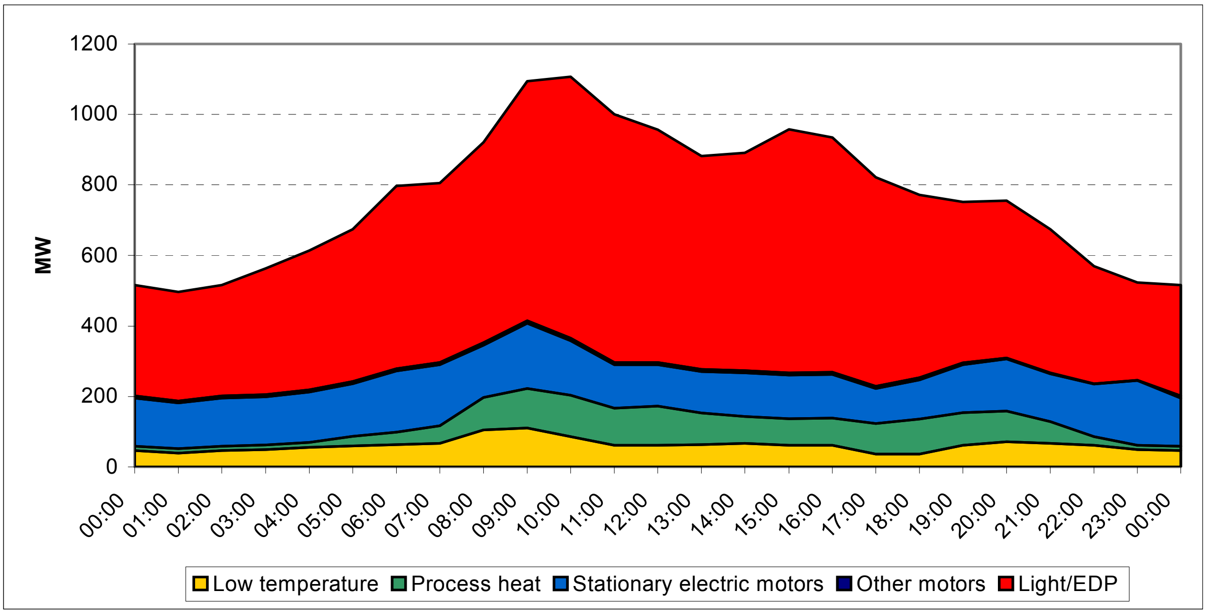

Figure 4.15: Aggregated load shape for the public sector for January 18, 1995. Source: /40/

4.6.5 Aggregated demand for the residential sector

The most energy intensive appliances for the residential sector are electrical heating and water heating devices (low temperature in Figure 4.16). The change of an electrical water heating system or an electrical heating system is a very difficult job. Because of structural boundaries of the building not every customer can change the heating or water heating system. Additionally, the change of the system is very cost intensive and for some old buildings no alternatives to electrical systems exists. Therefore, for all further investigations only the "light/EDP", "stationary motors" and "process heat" appliances are considered. The light/EDP devices contribute with 461.5MW to the 18.00 hours peak. From this value the television sets have to be subtracted. The yearly consumed electricity is 2% of the total electricity consumption of all households in Austria. With the assumption that all TVs are switched on during the on-peak hours for 2 hours each day the 2% energy percentage can be transformed to a 1% power value. Furthermore, the power demand for personal computers is assumed to be equal to the demand of all TVs. These assumptions result in a light load of 452.27MW and an EDP load of 4.6MW respectively.

In contrast to the stationary motor load from the industry and commercial sector the stationary motor load in the residential sector is mainly determined by refrigerators, freezers and pump loads. However, in this work only refrigerators and freezers are considered. The calculation of the refrigerator and freezer load is simple. Refrigerators and freezers are switched on for 8760 hours a year. Therefore, the entire yearly electricity consumption of 12,726.3GWh/year for the residential sector can be multiplied with the respective share for these appliances (refrigerator = 7% and freezer = 9%) and divided by 8760 hours. These calculations result in a freezer load of 130.75MW and refrigerator load of 101.7MW.

The process heat contributes with 307.69MW to the 18.00 hours peak and is mainly driven by electrical cooking systems, dish washers, washing machines and driers.

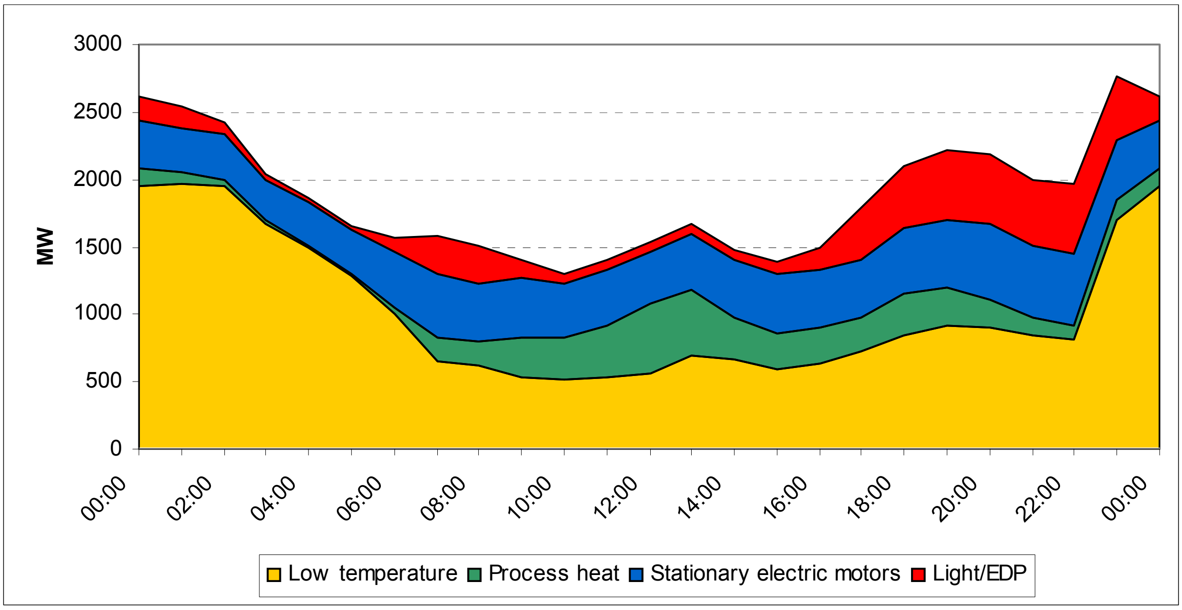

Figure 4.16: Aggregated load shape for the residential sector for January 18, 1995. Source: /40/

4.6.6 Overview of the most important appliances

Table 4.4 shows the most energy intensive applications considered in this work for the industry, commercial, public and residential sector and the respective load at 18.00hours. All specified applications can easily replaced by high efficiency devices. Therefore, no electrical heating systems or electrical water heating systems are considered as emphasized in chapter 4.6.5. The "X" in Table 4.4 indicates the minor relevance of the considered application for a certain sector.

Sector	Light/EDP [MW]		Stationary motors [MW]		Process heat [MW]	
	Light	EDP	Freezer	Refrigerator	Electrical cooking, dish washer, washing machine, and drier	
Industry	X	X	X	X	X	
Commercial	403.91	170	X	X	X	
Public	429.09	89.43	X	X	X	
Residential	452.27	4.6	130.75	101.7	307.69	
Sum	**1,285.27**	**264.03**	**130.75**	**101.7**	**307.69**	**2,089.44**

Table 4.4: Identification of the most energy intensive appliances and respective loads at 18.00 hours

4.7 Aggregated long term demand curve

4.7.1 General considerations

At this point a very simple long term demand curve for the critical winter months is developed. However, not all possible DS-measures are considered in this demand curve. Only a few simple measures are used to show the principle effects of the developed model.

As mentioned in chapter 2.3 two different DSM-measures exist:

- Efficiency increasing measures and
- Load shift measures

To derive the long term demand curve for the critical winter time at 18.00 hours the commercial, public and household sector have been considered. It is assumed that the industry sector has no major contribution to the reduction potentials at the 18.00 hours spike in winter months.

According to the efficiency increasing measures it needs to be pointed out that only damaged or old applications with paid off credits have been replaced. That means, no remaining investment costs for the broken or old application have to be considered.

4.7.2 Efficiency increasing measures

In principle four efficiency increasing measures for the commercial, public and household sector have been considered:

- Exchange of ordinary light bulbs with high efficiency light bulbs
- Exchange of class C freezers with class A freezers
- Exchange of class C refrigerators with class A refrigerators
- Exchange of class C washing machines with class A washing machines
- Exchange of 17"CRT monitors with 17" TFT monitors

The application of these efficient measures depend on the electricity tariff charged by the supplier, the investment costs for the new high efficient application as well as the energy consumption of the appliances[60]. Consumers estimate the following mathematical equation with an individual decision making process to get the application tariff (=attractive tariff).

$$\begin{aligned} & I_{Alternative} \times \alpha \times n + (OM_{Alternative} + p_{Electricty} \times q_{Alternative}) \times Lifetime = \\ & I_{Basic} \times \alpha \times n + (OM_{Basic} + p_{Electricty} \times q_{Basic}) \times Lifetime \end{aligned} \qquad \textbf{(4.7)}$$

$I_{Alternative}$	*Investment costs for high efficiency application [€]*
α	*Capital recovery factor (annuity) for high efficiency and inefficient application (the payback time is assumed to be equal for each application)*
$OM_{Alternative}$	*Operation and maintenance costs for high efficiency application [€/year]*
$q_{Alternative}$	*Electricity consumption of high efficient application [kWh/year]*
Lifetime	*Lifetime (the lifetime is assumed to be equal for each application) [years]*
$p_{Electricity}$	*Electricity tariff [€/kWh]*

[60] In practice not only the charged tariff and costs for the new and old application are important. The income of the customer as well as the personal preferences contribute to the decision making process. Eventhough they are neglected in this aggregated approach.

I_{Basic} *Investment costs for inefficient application [€]*
OM_{Basic} *Operation and maintenance costs for inefficient application [€/year]*
q_{Basic} *Electricity consumption of inefficient application [kWh/year]*

With the definition of the capital recovery factor (annuity):

$$\alpha = \frac{(1+i)^n \times i}{(1+i)^n - 1} \qquad \textbf{(4.8)}$$

i interest rate
n payback time (or deprecation time[61])

To find the attractive tariff for the high efficient device the total costs for the new high efficient alternative application have to be the same as the total costs for the basic inefficient application. Usually, the alternative applications are characterized by higher investment costs than the basic application. However, if the electricity price is high enough the lower consumption of the alternative application leads to a break even point in total costs.

$$\frac{(I_{Alternative} - I_{Basic}) \times n \times \alpha + (OM_{Alternative} - OM_{Basic}) \times Lifetime}{(q_{Basic} - q_{Alternative}) \times Lifetime} = p_{Electricty} \qquad \textbf{(4.9)}$$

The charged electricity tariff differs from the spot market price required for the model regarding to chapter 3. Therefore, the charged (attractive) tariff has to be converted into the spot market price by a certain factor depending on the consumer sector (commercial, public or residential) which is explained in more detail in chapter 4.7.3.

4.7.2.1 Exchange of ordinary light bulbs with high efficiency light bulbs

High efficient light bulbs use only 20% of the energy of ordinary light bulbs for the same service (light) output and their lifetime is ten times higher compared to ordinary bulbs (see also /13/). This higher lifetime for high efficient bulbs is very important for the service output. Consumers want to have the same service output from the alternative and basic application. This means, if the consumer decides to buy an ordinary light bulb he or she has to buy approximately ten ordinary light bulbs to get the same service output. Therefore, the investment costs for ordinary light bulbs have to be multiplied by ten. The consideration of operation and maintenance (OM) costs for light bulbs is not necessary and therefore the two OM terms can be neglected. Furthermore, bulbs are very cheap compared to the income of a household and therefore the annuity can be neglected. No consumer estimates the payback time (depreciation time) or interest rate of a light bulb. Because of this "short" payback time the annuity can be set to one.
Therefore, for light bulbs the above given equation can be simplified:

$$\frac{I_{Alternative} - I_{Basic} \times 10}{(q_{Basic} - q_{Alternative}) \times Lifetime_{Alternative}} = p_{Electricty} \qquad \textbf{(4.10)}$$

[61] Depreciation time is regulated by law. In contrast to the depreciation time payback time specifies the individual time for the repayment of a loan.

Service	Average investment costs for basic application without VAT [€]	Average investment costs[62] for alternative application without VAT [€][63]	Lifetime of alternative bulb [hours]	**Application tariff without VAT [€/MWh]**	Comment
100W	0.62	12.5	10,000	**8**	Alternative application: 20W high efficient bulb
60W	0.52	9.2	10,000	**8.2**	Alternative application: 11W high efficient bulb

Table 4.5: Necessary data for the derivation of the application tariff for high efficient light bulbs

The rational insertion point for high efficient light bulbs would be 8€/MWh. This value is far below the charged electricity tariffs. If the application price is so low this voices the question why no one is using high efficient light bulbs? The answer is very clear: Obviously, the consumers do not understand the function of high efficient light bulbs[64].

The reasons for this consumer behavior are less information about:

- The ten times higher lifetime of high efficient bulbs compared to ordinary bulbs. This means, the consumers neglect the factor ten in (4.10). To approximate the real decision making process the factor ten has to be neglected in the calculation.
- Consumers assume a lower lifetime in the range of ordinary light bulbs. This assumption leads to an anticipated lifetime in the range of 1,000 hours (which corresponds with a lifetime of approximately one to three years).

Therefore, consumers anticipate the same lifetime for both applications and compare only the investment costs and the energy costs on basis of the same lifetime.

This conclusion leads to a modified (real) decision making process:

$$\frac{I_{Alternative} - I_{Basic}}{(q_{Basic} - q_{Alternative}) \times Lifetime_{Basic}} = p_{Electricty} \qquad \textbf{(4.11)}$$

Service	Average investment costs for basic application without VAT [€]	Average investment costs[65] for alternative application without VAT [€][66]	Anticipated lifetime of alternative bulb [hours]	**Application tariff without VAT [€/MWh]**	Comment
100W	0.62	12.5	1,000[67]	**148.5**	Alternative application: 20W high efficient bulb
60W	0.52	9.2	1,000	**177.1**	Alternative application: 11W high efficient bulb

Table 4.6: Necessary data for the derivation of the application tariff for high efficient light bulbs with the modified decision making process based on (4.11)

[62] Inclusive deposit for disposal
[63] Source: http://www.eva.ac.at/stromspar/lampen.htm
[64] This is not the only reason. For locations with only short usage durations high efficiency bulbs are not suitable.
[65] Inclusive deposit for disposal
[66] Source: http://www.eva.ac.at/stromspar/lampen.htm
[67] 1,000 hours are approximately equal to a lifetime of one to three years.

4.7.2.2 Exchange of class C freezers[68] with class A freezers

Because of the huge variety of different freezers it would be very complex to collect all the different freezer types used in Austria. Therefore, it is necessary to define a "standard" size for a freezer. In this context a standard freezer is defined by a volume of 165 liters. In this chapter the application tariff for an approximately 165 liters class A freezer compared to a 165 liters class C freezer is calculated.

$$\frac{(I_{Alternative} - I_{Basic}) \times \alpha \times n}{(q_{Basic} - q_{Alternative}) \times Lifetime} = p_{Electricty} \tag{4.12}$$

Manufacturer	Volume [liter]	Investment costs without VAT [€]	Class	Electricity consumption per year [kWh/year]	Lifetime [years]	Payback time [years]	Interest rate per year [%]	Annuity (capital recovery factor)	**Application tariff without VAT [€/MWh]**
Candy	159	514.2	A	245	12	3	10	0.402	**114**
Ignis	165	332.48	C	405	12	3	10	0.402	**X**[69]

Table 4.7: Necessary data for the derivation of the application tariff for a "standard" class A freezer. Source: /13/

4.7.2.3 Exchange of class C refrigerators[70] with class A refrigerators

According to refrigerators the "standard" size is defined by a volume of 150 liters (see also /13/).
In this chapter the application tariff for a 150 liters class A refrigerator compared to an approximately 150 liters class C refrigerator is calculated.

Manu-facturer	Volume [liter]	Investment costs without VAT [€]	Class	Electricity consumption per year [kWh/year]	Lifetime [years]	Payback time [years]	Interest rate per year [%]	Annuity (capital recovery factor)	**Application tariff without VAT [€/MWh]**
Electro-lux	150	362.76	A	128	12	3	10	0.402	**100.5**
Ignis	154	253.75	C	237	12	3	10	0.402	**X**

Table 4.8: Necessary data for the derivation of the application tariff for a "standard" class A refrigerator. Source: /13/

4.7.2.4 Exchange of class C washing machines[71] with class A washing machines

In this work a standard washing machine is defined by a volume of 5kgs. In this chapter the application tariff for a 5kgs class A washing machine compared to a 5kgs class C washing machine is calculated. In Table 4.9 the necessary data for the calculation are shown.

[68] Only freezers without a refrigerator part are considered. This means, no combined refrigerators/freezers have been taken into account.
[69] Only for high efficient devices an application tariff can be calculated.
[70] Only devices without a freezer are considered.
[71] Only washing machines without a drier are considered.

To calculate the number of programs needed per year for an average household it is necessary to estimate the number of programs needed per week and person. The number of programs per person and week is estimated with two. Assuming 3 persons in an average household and multiplying this with 52 weeks a year an average number of programs per year of 312 is obtained.

$$Number\ of\ programs\ per\ year = 2\frac{programs}{person}\times 3\frac{persons}{household}\times 52 weeks\ per\ year = 312\frac{programs}{year} \quad \textbf{(4.13)}$$

$$\frac{(I_{Alternative}-I_{Basic})\times\alpha\times n}{(q_{Basic}-q_{Alternative})\times Lifetime}=\frac{(483.88-302.74)€\times 0.402\times 3}{(1.33-0.95)kWh/program\times 312\times 12 program}=0.1535€/kWh \quad \textbf{(4.14)}$$

Manu-facturer	Volume [kg]	Investment costs without VAT [€]	Class	Electricity consumption per program [kWh/ program]	Lifetime [years]	Payback time [years]	Interest rate per year [%]	Annuity (capital recovery factor)	**Application tariff without VAT [€/MWh]**
Privilieg	5	483.88	A	0.95	12	3	10	0.402	**153.5**
Privilieg	4.5	302.74	C	1.33[72]	12	3	10	0.402	**X**

Table 4.9: Necessary data for the derivation of the application tariff for a "standard" class A washing machine compared to a "standard" class C washing machine. Source: /13/

4.7.2.5 Replacement of an ordinary 17" color monitor (CRT) with a 17" TFT monitor

Because of the higher lifetime of a TFT monitor the I_{Basic} investment has to be modified.

$$\frac{I_{Alternative}-I_{Basic}\times 7/3}{(q_{Basic}-q_{Alternative})\times Operation\ hours_{Alternative}}=p_{Electricty} \quad \textbf{(4.15)}$$

The investment costs are not such high than for freezers, refrigerators or washing machines. Furthermore, the payback time is assumed to be very short for monitors. A payback time of one year would results in a capital recovery factor of 1.1. Therefore, the capital recovery factor is set to one.

Name	Average investment costs without VAT [€]	Average power consumption [W]	Lifetime [years]	Operation time [h/day]	Operation days [days/year]	Operation hours [h]	**Application tariff without VAT [€/MWh]**
17" CRT	110	110	3	8	230	5,520	**207**
17" TFT	417	50	7	8	230	12,880	**X**

Table 4.10: Necessary data for the derivation of the application tariff for a "standard" 17" TFT monitor to a "standard" 17" CRT monitor

[72] Originally, the electricity consumption is 1.2 kWh/program. However, because of the less volume capacity of the Privilieg washing machine compared to the standard size 5kgs the electricity consumption has to be modified by the factor 5/4.5. This transformation leads to 1.33kWh/program.

4.7.3 Transformation to spot market price levels

As a next step the application (= attractive) tariff is converted to the spot market level.

In general, the ratio between the spot market price and the charged tariff depends on the following parameters:

- Customer cluster (households, public, commercial, or industry)
- Structural parameters of the customers (electricity consumption, volatility, and load factor)
- Region (e.g. states)
- Time

It is obvious that not all of these parameters can be taken into account when calculating the conversion factor. Additionally, there exist huge differences between the household/commercial sector and the industry sector. Therefore, the household and commercial sectors are combined to one group. The differences between the states are neglected because in this work an Austrian model with an aggregated Austrian supply curve is designed. However, the uncertainties of the supply and demand curves restrict the accuracy of the model. Therefore, only an average ration is necessary because a higher quality of the conversion factor does not lead to more accurate results of the model.

It is necessary to determine the average ratio between the spot market price and the average tariff. From the spot market database (see also chapter 4.2) the average Austrian spot market price can be taken. The average Austrian spot market price is 24.15€/MWh.
With Table 4.11 the electricity expenditures for an ordinary household - with 3,500kWh yearly electricity consumption - can be calculated.

Components	Price for a consumption of 3,500kWh a year [€]	Comments
Energy tariff	108.5	
Network tariff	201.8	(usage, losses, metering)
Fees (without VAT)	161.64	(Sales tax, stranded costs, extra charge for small hydro, extra charge for combined heat and power,…)
Total	393.28	

Table 4.11: Tariff components for a typical household in Austria with a yearly electricity consumption of 3,500kWh without VAT. Source: http://www.e-control.at/

The average total tariff of a household is about 11.2 €c/kWh (without VAT). The average charged tariff and the average spot market price lead to a ratio between spot market price and charged tariff of 0.22. Based on this ratio a transformation of the application tariff to an application spot market price is possible.

Sector	Average transformation factor f_T
Household sector	**0.22**
Commercial sector	**0.22**
Public sector	**0.22**

Based on the gathered information about the commercial sector under liberalization the same transformation factor for the commercial sector can be assumed.

Table 4.12: Average transformation factors for the residential, commercial and public sector in Austria

DS-measure	Attractive spot market price (application price) [€/MWh]
20W high efficiency bulb instead of 100W bulb	32.7
11W high efficiency bulb instead of 60W bulb	39.0
Class A washing machine	33.8
Class A freezer	25.1
Class A refrigerator	22.1
17" TFT monitor	45.5

Table 4.13: Attractive spot market prices for the considered DS-measures in Austria

The average transformation factor for the public sector is also assumed to be in the range of the transformation factor for the residential sector. Of course, for some big public institutions the average transformation factor might be lower. Because of the lack of qualified data no precise estimation is possible. A lower transformation factor results in slightly lower application prices for the devices in question. However, the lower application prices because of the lower transformation factor can be increased because of inefficient management in this sector.

This consideration shows impressively the huge variety of influencing factors on the decision making process. Not only the investment costs, annuity, efficiency and energy costs are responsible for the decision to buy a new device but also transaction costs and personal preferences are important which is very difficult to take into account. Therefore, a differentiation between the three considered sectors does not necessarily lead to a higher precision of the model.

4.7.4 Total long term demand curve for the commercial, public and residential sector used for analyses

In chapter 4.6.6 the most energy intensive loads separated into devices and sectors have been presented. As emphasized in the previous chapters no significant load reduction during on-peak hours from the industrial sector is expected (see also chapter 4.6.2).
To calculate the theoretical reduction potential the increase in efficiency for each applied alternative device must be obtained. This increase in efficiency can be gathered from chapter 4.7.2. For example the exchange of a 100W bulb with a 20W high efficiency bulb leads to an increase of 80% in efficiency.
In this work two different light bulb types have been considered:

- A 100W light bulb which gets replaced by a 20W high efficiency bulb and
- A 60W light bulb which gets replaced by a 11W high efficiency bulb

To simplify the demand curve the usage of the 100W light bulb (and 20W high efficiency bulb) is restricted to the commercial and public sector only. Furthermore, it is assumed that the 60W bulb (and the 11W high efficiency bulb) is only used in the residential sector. No 60W bulbs are used in the commercial and public sector.
The multiplication of the total load with the reduction potential results in the theoretical reduction potential. This potential must be corrected by the share of customers using Real-Time-Pricing. The share of customers using RTP is assumed to be 20% as explained in chapter 4.3.3. The usage of a RTP-share results in the feasible reduction potential (see Table 4.14).

Sector	Appliances	Load [MW]	Reduction potential [%]	Theoretical reduction potential [MW]	Estimated equivalent total number of devices	Share of used RTP systems	Feasible reduction potential [MW]	Costs [€/ MWh]
Industry	X	X	X	X	X	X	X	X
Commer.	Light	403.91	80	323.13	4,039,100	20[73]	64,63	32.7
	EDP – monitors only	85	55	46.75	850,000		9.35	45.5
Public	Light	429.02	80	343.22	4,290,200		68.64	32.7
	EDP – monitors only	44.72	55	24.60	447,200		4.92	45.5
Resident.	Light	452.27	82	370.86	7,537,833		74.17	39
	EDP – monitors only	2.3	55	1.27	23,000		0.25	45.5
	Freezers	130.75	34	44.46	2,842,391		8.89	25.1
	Refrigerat.	101.7	46	46.78	~All households		9.36	22.1
	Process heat	307.69	60	184.61	307,690[74]		37.00	42
							264.834	

Table 4.14: Derivation of entire long term demand curve used in this work for on-peak hours (≈ 18.00 hours) during winter months

Regarding to the EDP appliances the energy consumption of monitors and personal computer has been considered. However, in the long term demand curve no efficiency increase for personal computers has been considered. With the approximation that 50% of the EDP load is produced by monitors the EDP load has to be divided by two to get the electricity consumption of 17” CRT monitors.

It is not possible to calculate the costs of process heat appliances in the same way as for the other appliances as shown in chapter 4.7.2 because the aggregated load of all process heat appliances is available. No detailed information about the load of washing machines, electrical cooking systems, dish washers and driers has been available. Because of this lack of information no approximation of the reduction potential of each application was possible.
Therefore, a different approach was chosen. From chapter 4.5 the short term demand curve for 20% of all household customers is known. This short term demand curve considers all measures which shift the load from on-peak hours to off-peak hours because of the fact that electrical cooking, dish washer, washing machine and drier appliances are typical shift applications. However, refrigerator or freezer load as well as the light appliances are not easy to shift.
The short term demand curve is characterized by loss in service at 18.00 hours. The load is shifted to an off-peak hour. If the price is high for a longer period the customers want to regain the loss in service and will invest in high efficiency devices. This means the regarding

[73] This approach requires that 20% of the considered appliances are changed in a simple way. The old inefficient appliances must be fully depreciated (or repaid) or damaged. No one changes an electrical cooking system which is only one year old. Therefore, it is assumed that the share of old or damaged devices is higher than 20%. Of course to evaluate this assumption a detailed investigation of the age of all considered appliances would be necessary. Such an investigation is planned for the near future.
[74] The regarding power is estimated to 1kW.

on-peak price for a certain load reduction in the short term demand curve quantifies the worth of a certain DS-measure. Therefore, this value quantifies also the costs for DS-measures for household customers in the long run.
The total load of 307.69MW for all process heat appliances has to be modified by the assumed reduction potential of 60%[75]. As a result of this multiplication the theoretical reduction potential of 184.61MW can be obtained. Furthermore, the theoretical reduction potential has to be modified by the share of customers using RTP. The corresponding on-peak price for the 37MW feasible reduction has to be taken from Figure 4.12 in chapter 4.5. The obtained on-peak price of 42€/MWh quantifies the average costs for the application of high efficiency electrical cooking systems[76], dish washers, washing machines and driers for average household costumers in Austria[77].

The Rebound Effect which is explained in chapter 2.2 can be neglected because it can be assumed that no major increase in service demand results for the considered DS-measures.

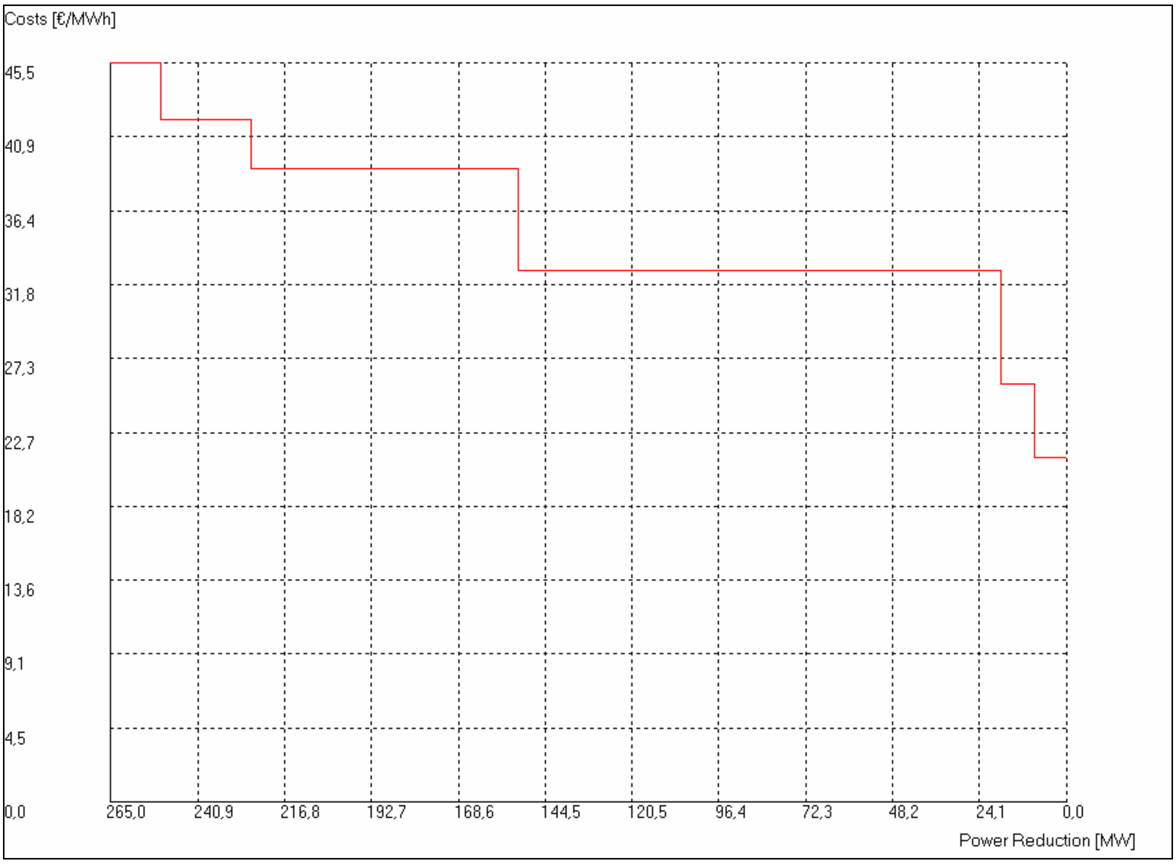

Figure 4.17: Entire long term demand curve[78] used in this work for on-peak hours during winter months - 20% of all customers using RTP

[75] Comparisons between alternative and basic applications for washing machines, dish washers, driers and electrical cooking systems results in an average reduction potential of 45%. See also /13/. This reduction potential does not include the switch from electricity to gas as the primary fuel. Therefore, the effective reduction potential must be higher. As a result of this reflection the effective reduction potential is estimated with 60%.
[76] From chapter 4.7.3 the attractive price for the insertion of a high efficiency washing machine is known. This value is 33.8€/MWh and lower than the average insertion price of 42€/MWh in this chapter. The 42€/MWh is higher because of the consideration of electrical cooking systems which are very difficult to replace. The price (tariff) must be high for a long period that the customers will react and replace the cooking system.
[77] The value of 42€/MWh includes also transaction costs compared to the application prices form chapter 4.7.3.
[78] Note: The shown demand curve is a hardcopy of the software tool "NESoDSM" with German comma settings

4.8 Actual Austrian supply structure

For the estimation of benefits and costs of DS-measures a national supply curve is a necessity. The bases for the determination of the supply curve are the "Brennstoffstatistik" 1995 and the "Betriebsstatistik" for 2001. Unfortunately, no detailed "Brennstoffstatistik" has been available since 1995. Therefore, it is necessary to use the 1995 edition and modify the data to match the aggregated statistic from the "2001 Betriebsstatistik".

Power plant type	Total power [MW]	
	Maximum power	Utility owned maximum power
Run-of-river plants	5,271.9	4,954.3
Storage power plants	6,395.6	6,143.1
Thermal power plants	6,422.2	5,250.8
Wind farms	95.0	68.6
	18,184.7	**16,417.1**

Table 4.15: Total installed capacity [MW] in Austria at the end of 2001. The calculated "Maximum power" values include also companies with their own power production. Source: /34/ and /43/

From the "Brennstoffstatistik" for 1995 the short run marginal costs for all thermal power plants can be calculated. Detailed data for all Austrian thermal power plants are shown in the appendix (chapter A.2).
In 1995 the installed capacity of utility[79] owned thermal power plants amounted to 4,984MW, whereas in 2001 this amount increased to 5,250.8MW. A comparison of these two values results in a difference of 266MW. The higher value in 2001 is mainly explained by the new thermal power plant "Donaustadt 3" and the shut down of "Korneuburg". After consideration of the new gas fired power plant "Donaustadt 3" and the removal of "Korneuburg" the total installed capacity of thermal power plants is approximately 5,250MW.

Most of the thermal power plants are very old and therefore no capital costs must be considered when calculating their marginal costs. Furthermore, due to the lack of information about the costs for operation and maintenance these costs are neglected. Hence, only the fuel costs contribute to the marginal costs.

For the calculation of marginal costs fuel costs must be estimated. These prices have been gathered from the International Energy Agency (IEA). The International Energy Agency provides an international statistic for oil, gas and steam coal prices paid by the utilities for electricity production. Unfortunately, the statistic for Austria is only available till 1995. As a result of this restriction estimations about the 2001 prices have been made with the result that the average 2001 prices are assumed to be approximately equal to the average prices of 1995.

The price for biogas, sewage gas and others is assumed to be determined by the gas price. Therefore, the price for other fuels was estimated to be equal to the gas price. However, this estimation has a minor effect on the supply curve, because only, few power plants use biogas as input factor for the electricity production. Hence, the effect of this assumption is marginal.

[79] The term utility indicates a company which is involved in production, transmission, and distribution. Since the liberalization this term is outdated. The more precise term in this context would be "producer".

Primary fuel	Price[80] [€/MWh]
Oil	8.26
Gas	11.86
Steam coal	7.53
Price others (e.g. biogas)	11.86

Table 4.16: Estimated average fuel prices for 2001 paid by Austrian utilities

The calculation of the short term average marginal costs for thermal power plants is very easy, because the "Brennstoffstatistik" for 1995 includes the yearly used primary energy for electricity production and the total electricity output per year.

$$C_{Marginal} = \frac{\sum_{i=oil}^{others} Price_{Fuel(i)} \times Input_{Energy(i)}}{Output_{Electricity}} \quad \textbf{(4.16)}$$

$C_{Marginal}$	Marginal costs short run [€/MWh]
$Price_{Fuel(i)}$	Fuel costs for primary energy (oil, gas, steam coal, and others) [€/MWh]
$Input_{Energy(i)}$	Yearly input of primary energy (oil, gas, steam coal and others) [MWh]
$Output_{Electricity}$	Yearly electricity output [€/MWh]
i	Fuel index. Oil, gas, steam coal, and others

Due to the high efficiency of combined heat and power plants (CHP) the production costs for electricity are lower than for ordinary thermal power plants. The calculation leads to low electricity costs for electricity produced by combined heat and power plants. In other words not only the sales from electricity determine the income of the regarding utility, but also, the revenues from the heat sales contribute to the coverage of fuel costs.
However, this approach is only valid for winter months, because of missing heat requirements in summer months the efficiency decreases and the costs for the electricity production increase.

During on-peak hours the intersection point between supply and demand curve is always in the sector of thermal[81] power plants (see also Figure 4.18). No run-of-river plants are located in the price range of thermal power plants. Due to the fact of marginal production costs and the fact that run-of-river plants are used to provide electricity 24 hours a day no influence with the intersection point between supply and demand during on-peak hours exist.
Therefore, it is not necessary to estimate the costs for electricity produced by run-of-river plants. According to storage power plants it can be observed that they are settled either slightly above the costs of thermal power plants or slightly below. For reasons of simplicity all storage power plants are considered to settle below the costs of thermal plants. Therefore, a huge block of water power plants is below the block of the thermal power plants block in Figure 4.18. Hence, only the installed capacity of all water plants is necessary to complete the supply curve.

[80] Without VAT
[81] Currently, the supply of electricity from wind farms is neglected, but in 2010 these farms will contribute up to 1,500MW to the supply. The average production costs for wind farms are estimated with 6€c/kWh for 2010. Therefore, the intersection point between supply and demand will be in the sector of thermal power plants and wind farms.

Source: Brennstoffstatistik 1995			2001	Specific CO_2 emissions
Power plant	Utility	Maximum power	marginal costs short run	Electricity plus heat production
		MW	€/MWh	tCO_2/MWh
Donaustadt	Wienstrom	324	32.73	0.562
Leopoldau	Wienstrom	156	24.82	0.247
Simmering	Wienstrom	800[82]	27.74	0.330
Dürnrohr	EVN	352	21.09	0.701
Theis DT	EVN	412	30.50	0.545
Theis GT	EVN	140	41.98	0.745
FHKW Mödling	EVN	3	19.86	0.250
Riedersbach I	OKA	55	24.69	1.043
Riedersbach II	OKA	165	20.17	0.893
Timelkam II	OKA	60	27.97	1.053
Timelkamm GT	OKA	106	39.98	0.979
FHKW Graz	STEWEAG	57	35.78	0.246
MHKW Knittelfeld	STEWEAG	2	26.58	0.236
FHKW Mellach	STEWEAG	246	20.22	0.572
Neudorf / Werndorf	STEWEAG	110	30.41	0.479
Pernegg	STEWEAG	100	26.78	0.903
MHKW Rottenmann	STEWEAG	3	16.22	0.352
Dürnrohr	VK	405	21.00	0.718
Korneu II	VK	285	28.51	0.506
St. Andrä 2	DK	124	23.07	0.841
Voitsberg 3	DK	330	20.87	0.962
Zeltweg	DK	137	21.62	0.981
FHKW Kirchdorf	FHKW Kirchdorf	12	18.68	0.259
FHKW Klagenfurt	STW. Klagenfurt	28	20.93	0.379
FHKW Linz Mitte	ESG Linz	70	29.94	0.479
FHKW Linz Süd	ESG Linz	116	22.65	0.325
HKW Salzburg Mitte	STW. Salzburg	18	27.35	0.445
HKW Salzburg West	STW. Salzburg	3	15.20	0.241
HKW Salzburg Nord	STW. Salzburg	14	10.59	0.314
FHKW St. Pölten Nord	STW. ST. Pölten	14	15.11	0.264
FHKW St. Pölten Süd	STW. ST. Pölten	5	16.37	0.278
FHKW Wels	EW Wels	15	29.99	0.304
Donaustadt 3	Wienstrom	350	29.96	0.560

Table 4.17: Estimated marginal short run costs for thermal power plants. Source: "Brennstoffstatistik 1995" and own calculations

[82] The installed capacity is 999MW, but because of environmental aspects only 800MW are allowed to be online.

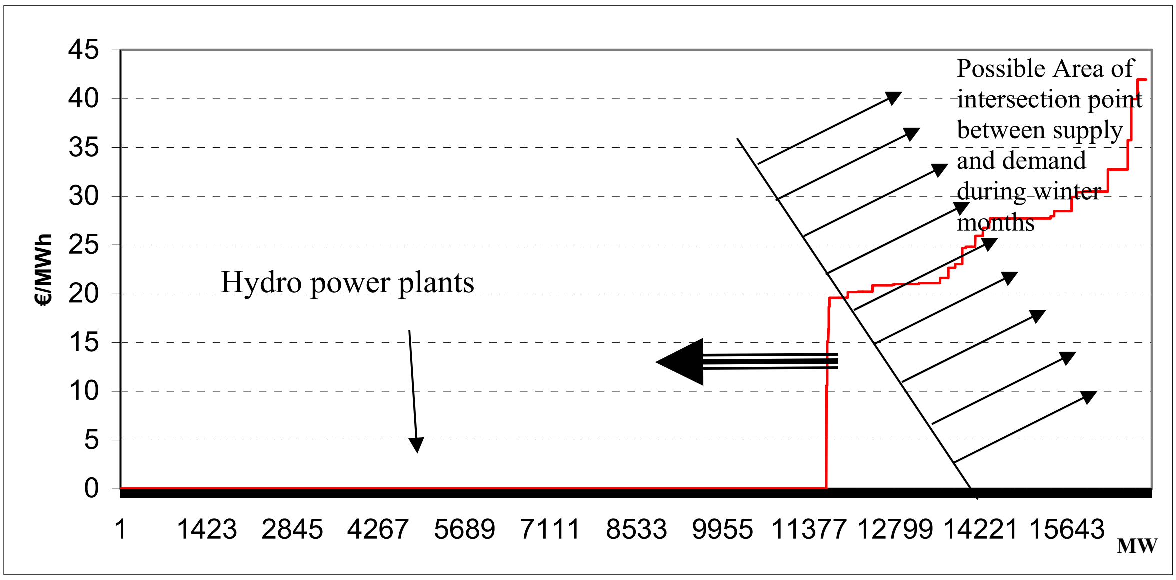

Figure 4.18: Theoretical supply curve for Austria in 2001. Source: Betriebsstatistik, Brennstoffstatistik and own calculations

This theoretical supply curve can not be used in the model because the supply curve must be shifted left because of the less water availability during winter months. It is assumed that all thermal plants operate with full capacity because of the lack of water during winter months.

The left shifting of the theoretical supply curve is carried out by the software tool "NESoDSM".

5 Scenarios for future development of major impact parameters

5.1 Forecast of electricity demand in Austria without any DSM till 2010

5.1.1 Introduction

The goal of this chapter is to develop a forecast for the electricity demand, especially for the yearly peak, till 2010. The influence of the most important parameters (temperature, gross domestic product) is investigated under the important condition of deregulation of the electricity market.
The prognosis is made on a monthly basis for each third Wednesday each month. The analysis is focused on the total electricity supply[83]. Because of the lack of sufficient power plants in the future the peak hours 12.00 hours and 18.00 hours are especially important for DSM-measures and therefore, a special focus on these hours is necessary. Additionally, also the forecast for the yearly peak till 2010 is shown.
With a linear regression of the most important parameters the future development in demand was forecasted based on historical files from 1980 to 2000[84]. The most important parameters are electricity price[85], income, change in structure and climatic parameters. In order to consider the change in the economy in the late 80's the analysis is based on the historical files from 1990 to 2000, only.

5.1.2 Historical trend

5.1.2.1 General point of view

For the analysis the power values for each third Wednesday from January 1980 to December 2000 are used.[86] Because of the fact that data for the year 1998[87] has been deleted this year has been excluded from all further investigations. The forecast considers only the inland electricity consumption without taking into account the power demand for pumped hydro power. Additionally, this approach is based on the schedule that during peak hours pumped hydro power does not effect the analysis because during peak hours pumped hydro power plants are not operating in the pumped mode. These power plants produce power during peak hours and therefore they are considered as consumers and not producers.
Because of a change in the data structure in 1998 the consumption of the Austrian Federal Train (OBB) is also considered in the inland electricity consumption of the public electricity supply (öffentliche E-Versorgung). Since this year the consumption of the OBB is part of the inland electricity consumption and no detailed information about the OBB is available.
That means it was not possible to subtract the consumption of the OBB after 1998 from the inland electricity supply. For that reason the consumption of the OBB was added to the inland consumption of the public supply for all years before 1998.

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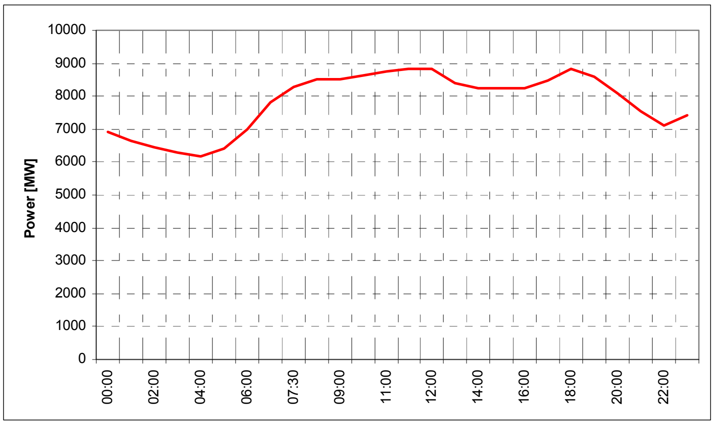
[83] This value of demand includes losses and the internal consumption of power plants.
[84] Unfortunately, only detail data until 2000 are available.
[85] The following analysis shows that an energy price [€/MWh] is not suitable to describe changes in power [MW].
[86] In principle investigations on the basis of the years 1980 to 2000 were made. However, these analyses have shown that forecasts on the basis of the years 1980 to 2000 will lead to unnatural high forecast values. Therefore, the investigation is limited to files from 1990 to 2000.
[87] Because of data deletion only information for summer and winter months is available. The investigation is based on each third Wednesday for each month, whereas data for each month would be appropriate.

The inland consumption of the total electricity supply (gesamte E-Versorgung) includes also the consumption of the OBB.

5.1.2.2 Total electricity supply

To generate a forecast of the peak hours it is necessary to identify the peak hours in the load curve. As can be seen from Figure 5.1 the hours 12.00 and 18.00 are the hours with the highest electricity consumption during a day. However, the yearly peak may not necessarily always appear at 12.00 hours or 18.00 hours.



A comparison of the power values for each third Wednesday each month from 1980 to 2000 shows that the yearly peak occurs mostly at 18.00 hours mostly during the months November, December or January.

Figure 5.1: Load profile of 20 January 1999, total electricity supply

The difference between the peak values at 18.00 hours and the actual yearly peak is marginal. For this reason the peak values at 18.00 hours are used to describe the yearly peak. This approach guarantees a homogenous model[88] to forecast the yearly peak.

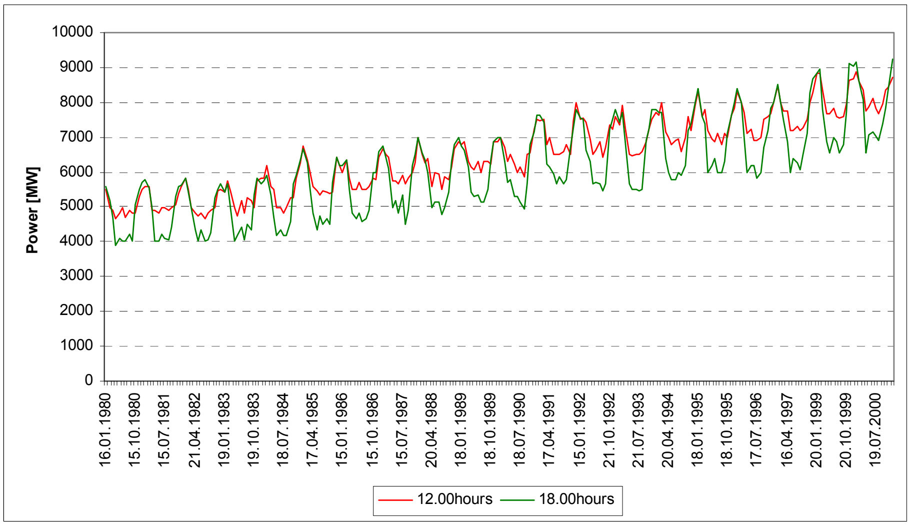


Figure 5.2: Historical trend for Austrian electricity load (total electricity supply) from 1980 to 2000 for 12.00 hours and 18.00 hours

[88] The problem with the actual yearly peaks is that the peaks occur at different times during a year. But, different times stand for different structures of the mathematical model. An analysis was made on basis of the actual yearly peaks and as expected the ex post forecast was of poor quality. The different peak times lead to poor R^2 values.

The seasonal fluctuation for the evening value (18.00 hours) is bigger compared to the seasonal fluctuation for the noon value (12.00 hours). This fact is shown in Figure 5.2. The maximum values increased from 1980 to 2000 for the hour 12.00 around 56% and for the hour 18.00 around 65%.

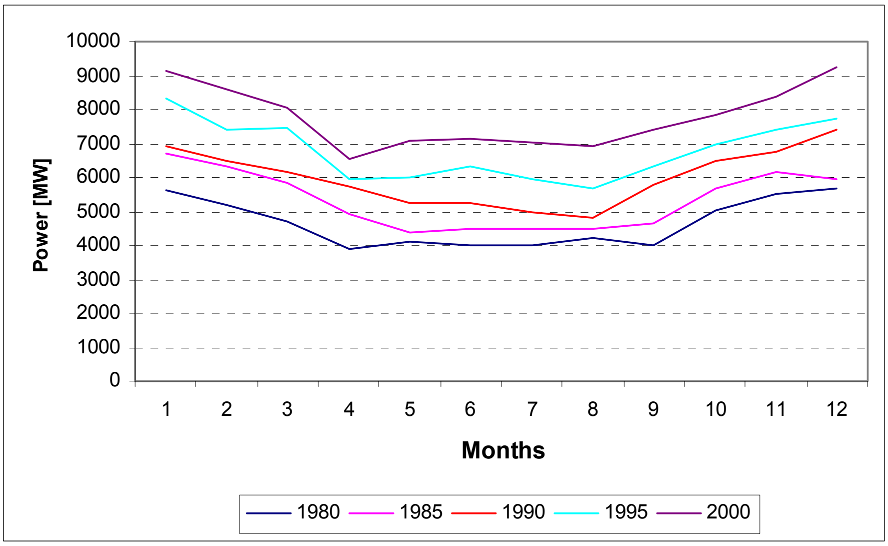


Figure 5.3: Seasonal trend for the demand in hour 18.00 for the total electricity supply

5.1.3 Discussion of the parameters influencing load

As shown in the historical analyses the gross domestic product (GDP) – a criterion for the income - climate data and the price are the most influencing parameters on the power demand (see also Ramanathan /33/). The analyses show that the most important parameter of the demand is the GDP. Therefore, it is very important to estimate carefully the future development of the GDP. To estimate the influence of the climate on the power demand the daily average temperature of the Austrian state capitols are used. Besides the GDP and the temperature also changes[89] in price influence the power demand. Based on these observations in the following chapters the GDP, the daily average temperature and the (energy) price are discussed.

[89] Mainly the increasing price influence the power demand.

5.1.3.1 Gross domestic product (GDP)

The historical files and forecast of the GDP are gathered from the Austrian Wirtschaftsförderungsinstitut (WIFO).

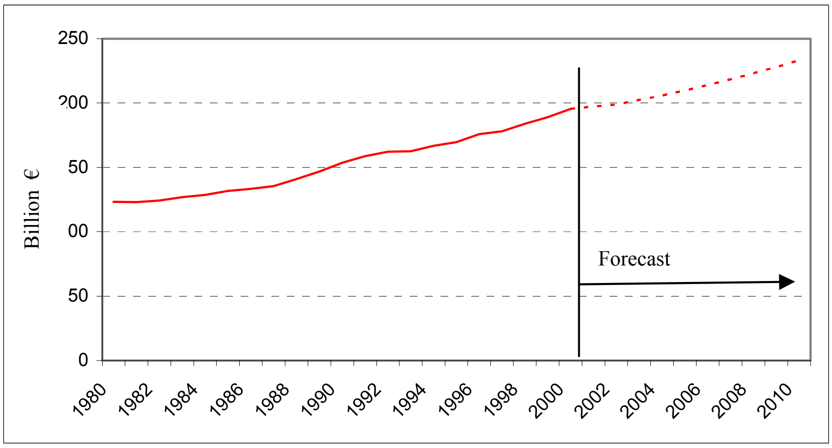


Figure 5.4. Trend of the real GDP from 1980 to 2010

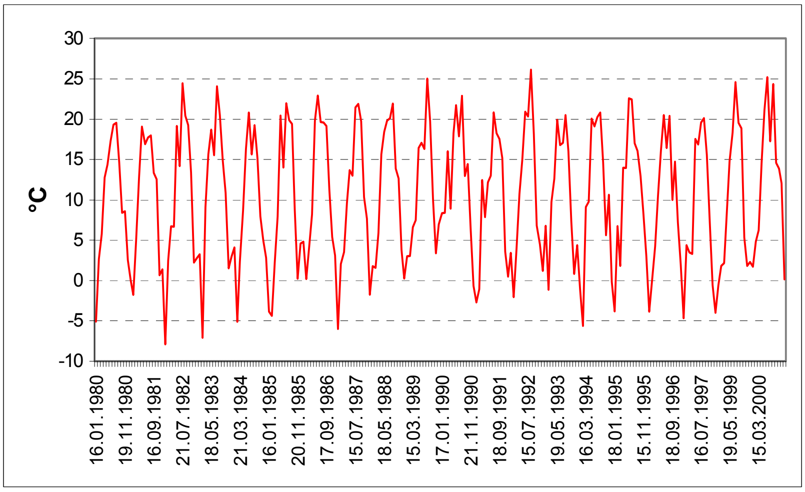
Year	Yearly growth compared to the year before	Real GDP [Billion €]
1980	2.91	123.39
1981	-0.26	123.07
1982	1.08	124.40
1983	2.01	126.90
1984	1.36	128.63
1985	2.44	131.77
1986	1.18	133.32
1987	1.67	135.54
1988	4.01	140.98
1989	4.08	146.74
1990	4.61	153.51
1991	3.44	158.78
1992	2.04	162.03
1993	0.37	162.63
1994	2.55	166.78
1995	1.72	169.65
1996	3.57	175.71
1997	1.36	178.09
1998	3.24	183.85
1999	2.85	189.09
2000	3.28	195.30
2001	1.00	197.26
2002	0.78	198.79
2003	1.80	202.37
2004	1.76	205.92
2005	1.87	209.78
2006	1.98	213.92
2007	2.08	218.37
2008	2.17	223.10
2009	2.23	228.09
2010	2.29	233.32

Table 5.1: Growth of the real GDP. Source: WIFO

5.1.3.2 Daily average temperature

a) Historical temperatures

As indicator for the temperature the person weighted daily average temperature of the Austrian state capitols have been used.



The graph shown in Figure 5.5 is similar to the graph of the power demand in Figure 5.2. As can be observed a good inverse correlation between the power demand and temperature is given, which means that low temperatures increase the power demand, whereas high temperatures decrease the power demand.

Figure 5.5: Person weighted daily average temperature of the Austrian state capitols for each third Wednesday of each month

Because of the obvious good negative correlation between temperature and power demand a high negative t- statistic value in the linear regression for the daily average temperature can be expected.

b) Daily average temperature

Unfortunately, a prognosis of the person weighted average temperature till 2010 is not possible.

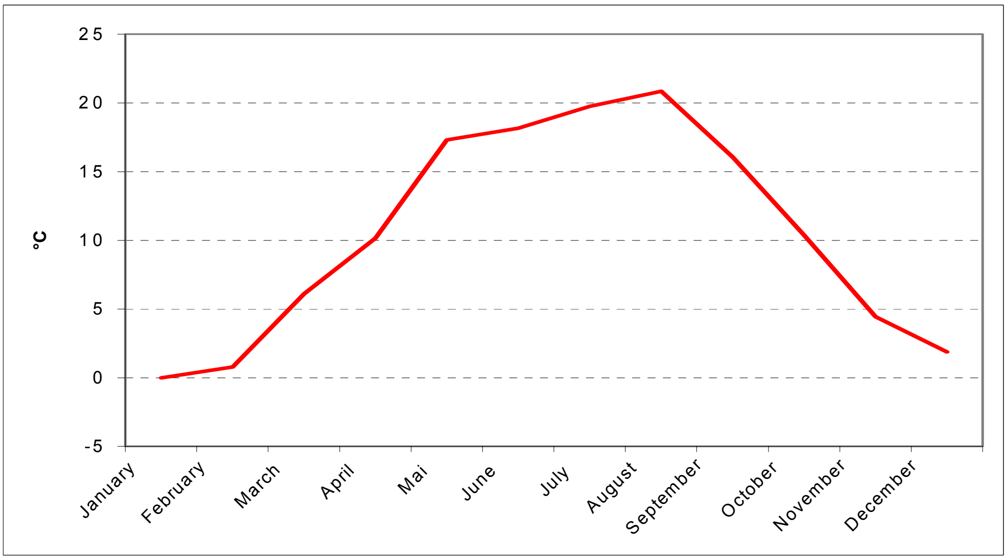


Figure 5.6: Average person weighted day temperature for every third Wednesday of the years 1980 to 2000

Month	Daily average temperature [°C]
January	-0.01
February	0.79
March	6.11
April	10.16
Mai	17.30
June	18.17
July	19.75
August	20.87
September	16.06
October	10.37
November	4.44
December	1.87

Therefore, the values of each third Wednesday for the last 20 years (1980 to 2000) are used to calculate an average temperature value for each month. These monthly average values are used as forecast for the average temperatures of each third Wednesday. The monthly average temperatures for the Austrian state capitols are always greater than zero, with the exception of January.

Table 5.2: Forecast of the daily average day temperature for the third Wednesdays from 2001 to 2010

5.1.3.3 Power price

At his point it is very important to differentiate between energy price and power price. In principle, yearly energy prices[90] are used in this analysis. Nevertheless, in this forecast the power is modeled, i.e. it is assumed that the energy price [€/MWh] is an indicator for the power price [€/MW]. The power price can be indicated by a constant energy price charged by the utility 365 days a year and 24 hours a day. In the past only in the industrial sector real power prices were charged and the yearly peak at 18.00 hours is mainly driven by the household sector. Whereas in the household sector no power price have been charged for the last 20 years and no Time-of-Use tariffs have been used either. Therefore, no significant historical files on power prices are available for this important sector. Furthermore, from Figure 5.7 it is evident that the real prices dropped steadily from 1980 to 2000. This development is supported by a prognosis from the WIFO which indicates also dropping prices in the future.

Therefore, these dropping prices are very important in the linear regression analysis. From investigations in the past it is known that during periods of dropping prices no significant price elasticity exists. In other words no influence of the energy price to the power consumption in the future is expected. Regression periods with dropping prices always lead to no plausible effects. Therefore, the energy price is not considered in this analysis.

[90] Source: Austrian Wirtschaftsförderungsinstitut (WIFO).

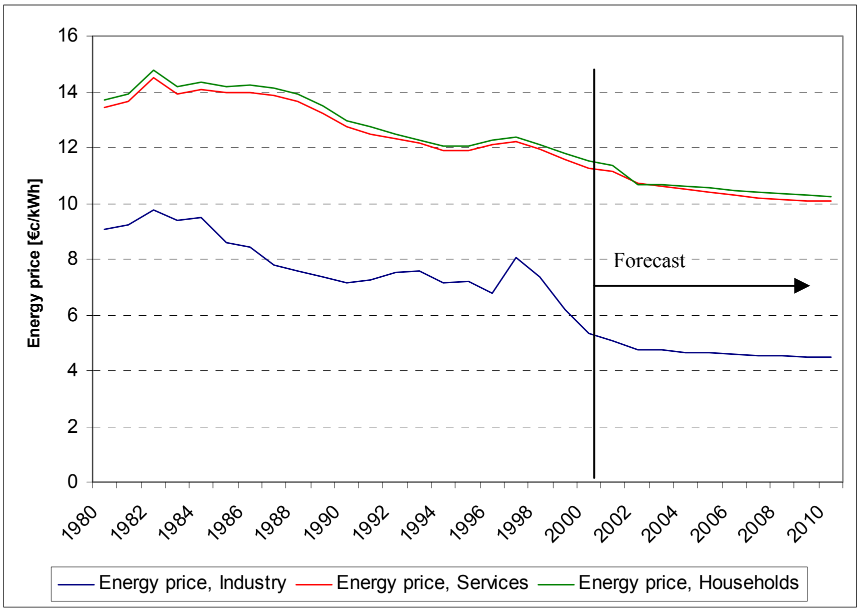


Figure 5.7: Electricity prices (energy prices) from 1980 to 2010[91]. Source: WIFO

5.1.4 Description of the used approach

The first step of a linear regression analysis is to find a mathematical connection between the observed historical values and the historical parameters (GDP, temperature, month,…). Once a model was found the mathematical linkage between the historical data and input data can be evaluated with help of the linear regression. The estimation is always done in that way that the sum of the square errors will be a minimum.
In general, the hypothesis about the mathematical function consists of following parts:

$$P = f(V_1, V_2, V_3, ...V_n, E_1, E_1, E_3, ...E_n, C_0, C_1, ..C_n) \quad \textbf{(5.1)}$$

$V_1, V_2, V_3, \ldots V_n$	Variables or parameters (temperature, GDP)
$E_1, E_2, E_3, \ldots E_n$	Exponents (elasticity)
$C_0, C_1, \ldots C_n$	Constants

To consider the different importance of the parameters a product approach of the influencing parameters and the exponents, as mentioned in most literature (e.g. Pindyck/Rubinfeld, Ramamathan), is used. Logarithmic calculus leads to the linear equation:

$$\ln(P) = C_o + E_1 \times \ln(V_1) +,...,+ E_n \times \ln(V_n) \quad \textbf{(5.2)}$$

Because of the fact that more observations than unknown variables exist an error ε_p has to be considered.

$$\ln(P) = C_o + E_1 \times \ln(V_1) +,...,+ E_n \times \ln(V_n) + \varepsilon_p \quad \textbf{(5.3)}$$

The unknown exponents and constants are calculated under the condition to minimize the sum of the square errors, i.e.

[91] 2% inflation per year was assumed for the years 2001 to 2010. But, the exact value of the inflation is only of minor importance in these investigations.

$$\sum_{p=1}^{N} \varepsilon_p{}^2 \rightarrow \min. \tag{5.4}$$

The value R^2 (also B) describes the quality of the estimation. It describes how good the assumed mathematical function describes the observed values under the condition minimizing the sum of the square errors. B is always in the range between zero and one.

$0<R^2<1$

If R^2 is near by one the historical observed values are well described by the mathematical approach. If R^2 is near by zero the mathematical function does not describe the observed values.

Very important for the assessment of the quality of the used approach is the t-statistic. The t-statistic indicates the importance of one selected parameter. The t-statistic is a statistical value which explains the importance of the selected parameters (temperature, GDP,…) in the regression model. The border for the importance is the value 1.96[92] (or -1.96 for negative exponents). If a t-test delivers a t-value greater than 1.96 (or less than -1.96) then the independent parameter (e.g. temperature or GDP) is important for the description of the mathematical model and the observed values.

Once a mathematical model with high t-values and B near by one has been found a forecast for the power demand on basis of the independent parameters (GDP, temperature) for future periods is possible.

5.1.4.1 Basic model to estimate future power demand

Based on historical documented investigations (see also Ramanathan, Pesaran, Pindyck/Rubinfeld) following product approach is used:

$$P = const \times Price^{\alpha} \times GDP^{\beta} \times \overline{Temp}^{\gamma} \times e^{\sum_{l=2}^{12} \sum_{i=2}^{12} S_{il} \times C_{il}} \times e^{\theta t} \tag{5.5}$$

P	Power
const	Constant
α	Price elasticity
β	Income elasticity
γ	Temperature elasticity
θ	Time trend
price	Real electricity price on yearly basis
GDP	Real gross doemestic product
Temp	Average person weighted day temperature of the Austrian state capitols
S_{il}	Monthly dummy
C_{il}	Monthly factor, $k_{il}=1$ for $i=l$, $i\neq l \rightarrow k_{il}=0$;

92 Precisely: The indicated value of 1.96 is only valid for infinite observations.

Logarithmic calculus leads to a linear problem as shown in (5.6) which can be solved with the linear regression approach:

$$\ln(P) = C + \alpha \times \ln(Price) + \beta \times \ln(GDP) + \gamma \times \ln(\overline{Temp}) + \sum_{l=2}^{12} \sum_{i=2}^{12} S_{il} \times C_{il} + \theta t \qquad \textbf{(5.6)}$$

with ln(const) = C.

The monthly factor and dummy create a specific monthly characteristic in the model. It is obvious that the factors have to begin in February (month 2) to avoid an insoluble problem. This means for the certain problem with twelve different months only eleven monthly factors are allowed.
The constant “const” is the only constant for January. January is the reference month in the model. In all other months the constant is modified by the monthly constant.

At this point it is possible to estimate the sign of the coefficients (factors):

i. β

   Normally, a higher income leads to a higher electricity consumption. Therefore, β is expected to be positive.

ii. Temperature

   Normally, colder days lead to higher heat load and higher electricity consumption. Therefore, γ is expected to be negative.

iii. Price

   In general a higher price leads to decrease in electricity consumption. Hence, a negative α can be expected. However, as emphasized in chapter 5.1.3.3 the price is from minor importance in the following analyses.

5.1.5 Final model[93]

With the above discussed parameters and the approach shown in chapter 5.1.4 estimations for the hours 12.00 and 18.00 have been made. Several estimations with different approaches for the mathematical function and different observation times have been performed. For the best model which is characterized by a high R^2 value, high t-values, important F-statistic, good DW-statistic, absence of auto correlation and absence of multicollinearity and heteroscedasticity the forecast on basis of the independent parameters (GDP and temperature, no price) can be carried out. The model with the best quality derived from the different estimations is shown in (5.7).

In Table 5.3 the results from the linear regression for the best model are shown. The analysis was made for the total electricity supply. The estimation delivers a positive income elasticity which is always less than one. Additionally, a positive direct influence of the GDP was found. As expected in chapter 5.1.4.1 the influence of the temperature on the price is indirect, i.e. lower temperatures lead to higher electricity consumptions. As Table 5.3 illustrates the most

[93] The final linear regression is based on historical data from 1990 to 2000.

important parameter in the analysis is the GDP. The t-statistic value for the GDP is always the highest value of all. The t-statistic value for the time trend is not significant. Therefore, the time trend is neglected in all further forecasts. The analyses show the known fact that the price is not significant during time periods with dropping prices. The energy price did not significantly influence the power demand. This effect is also assumed for the future because of the still decreasing prices and the WIFO price forecast which indicates dropping real prices till 2010.

Hence, the final model results in the following equation

$$\ln(P) = C + \beta \times \ln(GDP) + \gamma \times \ln(\overline{Temp}) + \sum_{l=2}^{12} \sum_{i=2}^{12} S_{il} \times C_{il} \qquad \textbf{(5.7)}$$

Case	C (t-statistic)	Income elasticity (β) (t-statistic)	Temperature (γ) (t-statistic)	B
12.00 hours, total electricity supply	11.1581 (10.67)	0.8988 (29.46)	-1.2109 (-6.61)	0.93
18.00 hours, total electricity supply	11.6280 (7.52)	0.9897 (21.95)	-1.3759 (-5.08)	0.94
Yearly peak	4.5218 (14.30)	0.8751 (14.23)	none	0.96

Table 5.3: Results from the linear regression for the best model[94]

As mentioned in Chapter 5.1.2.2 the prognosis for the yearly peak is based on the values for the hour 18.00. The linear regression for the yearly peak is based on the highest 18.00 hours value during a year. This means, that only one value per year is used which results in a different mathematical structure compared to the linear regression for the hours 12.00 and 18.00. The analysis for the two peak values at 12.00 hours and 18.00 hours uses twelve values a year for each time period. Therefore, these two different structures explain the different elasticities and constants.

5.1.6 Results of the ex-ante forecast

With the estimated constants, elasticity for the GDP (β), temperature elasticity (γ), the monthly dummies (S_{il}) and the prognosis for the GDP the forecast for the future power demand with the final model based on (5.7) was determined.

In Austria the yearly peak demand[95] will increase from 9.3GW in the year 2000 to 11GW in the year 2010 without any DSM-measures.

Figure 5.8 shows the historical and forecasted trend for the peak hours 12.00 hours and 18.00 hours for the total electricity supply from December 1990 to December 2010. It can be observed that the gap between the 12.00 hours peak and 18.00 hours peak will slightly increase, i.e the demand at 18.00 hours will have a slightly higher increase than the 12.00 hours peak demand. Additionally, also the seasonal fluctuations during a year will increase. Because of the usage of the average day temperatures as input data for the forecast the future trend looks more homogenous than the historical observed trend.

[94] Regression basis 1990 to 2000
[95] Total electricity supply

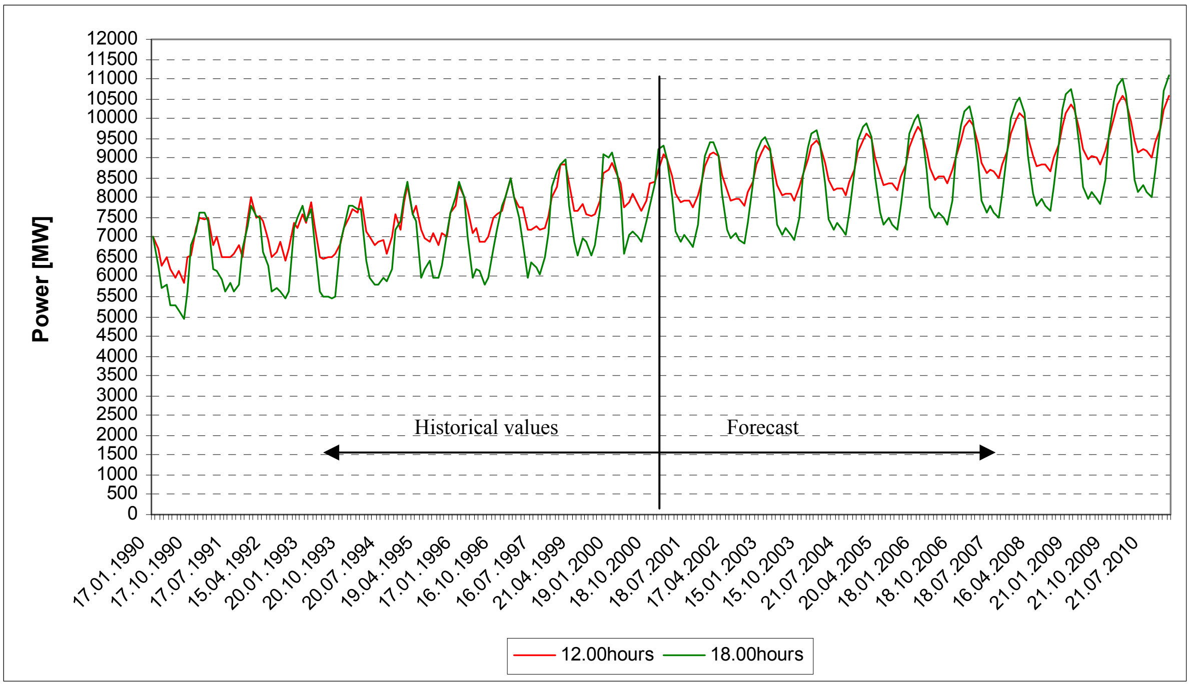


Figure 5.8: Trend of the peak load for 12.00 hours and 18.00 hours (third Wednesday) from 1990 to 2010[96]

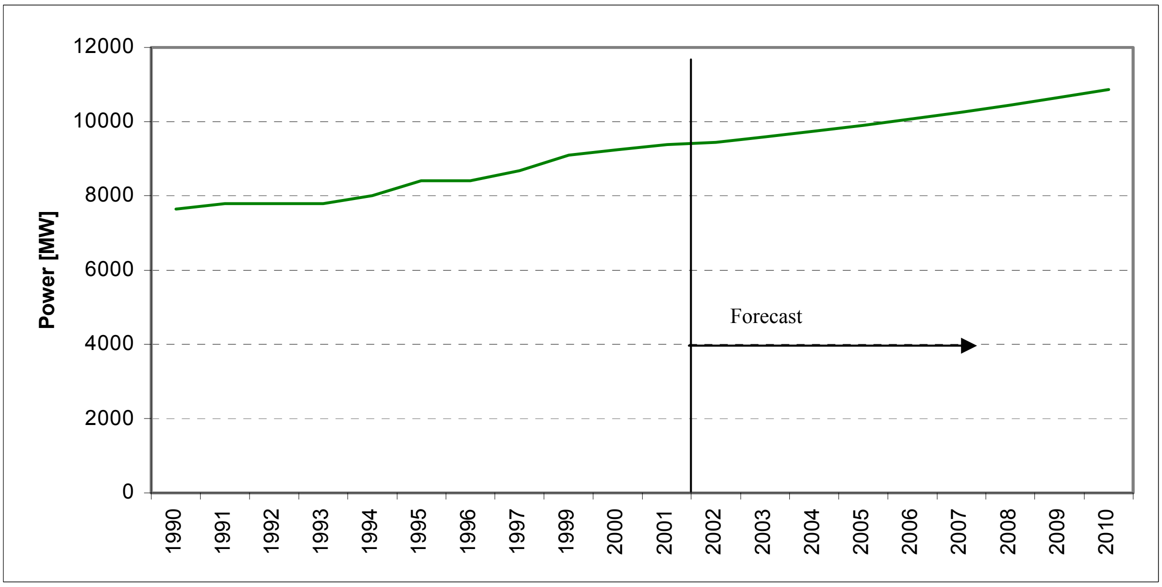


Figure 5.9: Trend for the yearly peak load [MW] from 1990 to 2010

As shown in Figure 5.9 the demand will be 10GW in the year 2006 with a further increase to 11GW till 2010. As a result of the expected lower economic growth (< 2%) in the years from 2001 to 2005 the yearly peak increases less compared to the years from 2006 to 2010 because the economic growth is expected to be higher than 2% for the latter five years.

[96] Total electricity supply

Year	Yearly peak [MW]
2001	9379
2002	9442
2003	9591
2004	9739
2005	9897
2006	10068
2007	10251
2008	10445
2009	10649
2010	10863

For the on-peak time 12.00 hours and 18.00 hours the same facts are valid. In the first five years the increase in power demand will be less than in the latter five years because of less expected economic growth for the first five years.

Table 5.4: Forecast for the yearly peak load from 2001 to 2010[97]

Time period	Increase[98] 12.00 hours [GW]	Increase[99] 18.00 hours [GW]	Increase yearly peak [GW]
1985 - 1980	1.23	1.19	1.19
1990 - 1985	1.04	1.05	1.15
1995 – 1990	1.19	1.2	1.10
2000 - 1995	1.07	1.09	1.10
2005 – 2000	1.08	1.08	1.07
2010 - 2005	1.10	1.11	1.10

Table 5.5: Rates of increase for the power demand from 1980 to 2010

5.2 Estimation of on-peak electricity price in winter months till 2010

The formal frameworks in chapter 3 developed require the exogenous international market price for a certain hour as basis for all calculations. Therefore, an estimation about the future market price must be performed.

The shown estimation is gathered from an internal study performed at the “Institut für Elektrische Anlagen und Energiewirtschaft” in the year 2000.

The most influencing parameters on future on-peak prices are:

- Degree of market opening
- Trend of gas and oil prices
- Efficiency trends of the utilities
- Increase in yearly demand
- Development of market concentration
- Extension of the European Union

The results for the scenario with increasing gas prices of 37% till 2010 are shown in Figure 5.10.

Equation (5.8) is used to determine the needed actual average on-peak prices for the comparison with the forecasted values.

[97] Total electricity supply
[98] Always the January value
[99] Always the January value

$$Value_{Year} = \frac{\sum_{m=November}^{January} \sum_{t=1}^{5} \sum_{i=9}^{20} P_{mti}}{Number} \quad \textbf{(5.8)}$$

$Value_{Year}$	Average price for winter months during peak hours[100]
m	Monthly index
t	Daily index (Monday to Friday)
i	Hourly index for peak hours (08.00 hours to 20.00 hours)

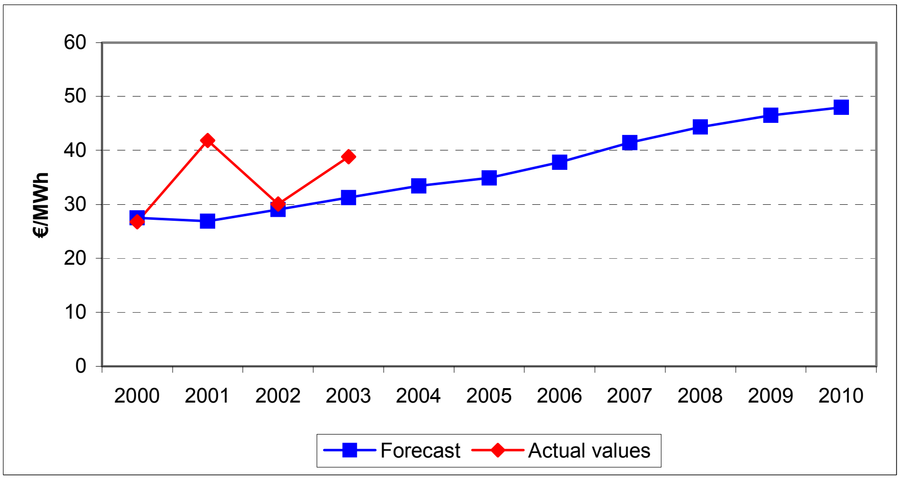


Figure 5.10: Trend of average on-peak prices during winter months till 2010. Source: Own calculations

Figure 5.10 shows the trend of the German wholesale price for on-peak hours[101] during winter months. The red line indicates the actual values of the reference market (EEX). Because of unexpected events (e.g. bankruptcy of ENRON) the value for 2001 is much higher than the calculated value for 2001. At the time of writing only the January value for 2003 was available, but the average value for January 2003 is also higher than the forecast value.

The wholesale price for peak hours during winter months will reach an average value of 48€/MWh till 2010. This increase is equivalent to a 66% raise in on-peak prices compared to 2002.

In this forecast no extraordinary scarcities in rainfalls are considered. Extraordinary lacks in rainfalls as in the months June and July 2003 will create additional price spikes much higher than the average values.

In chapter 5.1.3.3 a different forecast for the electricity price till 2010 is shown and was performed by WIFO and estimates the yearly average[102] electricity price. The yearly energy price regarding to WIFO remains stable on a low level. However, the forecast shown in this chapter is based on marginal costs[103] for the on-peak hours in winter months. Therefore, the two forecasts do not match.

[100] To obtain a uniform structure of the model also November, December and January are considered as winter months (see chapter 5.1.2.2.).

[101] On-peak hours: As mentioned earlier each market place has its own definition of on-peak hours. Because of the importance of the German market in Leipzig the EEX is used as reference for the Austrian market. On-peak hours at the EEX are from 08.00 hours to 20.00 hours.

[102] On basis of real energy prices

[103] Forecast of nominal values

5.3 *Expected future development of the supply curve till 2010*

As emphasized in chapter 4.8 the main drivers for the average marginal costs of thermal power plants are fuel costs. The forecast from the previous chapter for the on-peak hours for winter months shows an increase in average prices of 66%. This increase is mainly driven by the raise in fuel costs. The increase in gas and oil prices considered in the on-peak price forecast is 37.5% from the year 2000 to the year 2010. The steam coal price is considered to remain constant.

Primary fuel	Price [€/MWh]
Oil	11.36
Gas	16.30
Steam coal	7.53
Others (e.g. biogas)	16.30

In the model no change in the structure of thermal power plant is considered. It is assumed that no new power plants (except wind farms and hydro power plants) will be built till 2010.

Table 5.6: Estimated average fuel prices for the year 2010

The expected total installed capacity of wind farms of 1,500GW[104] in the year 2010 are not taken into account in the supply curve used in this work. The neglection of the wind farm capacity is explained by two facts:

- In this work the effects of DS-measures and not the effects of the new renewables are investigated and
- The total installed capacity is mostly not available: Because of the volatility of the wind the power production is as also very volatile. In the worst case no wind is available and therefore no energy is produced by these wind farms. Hence, the situation with no wind and lack of supply is the interesting case for DS-measures and therefore investigated in this work.

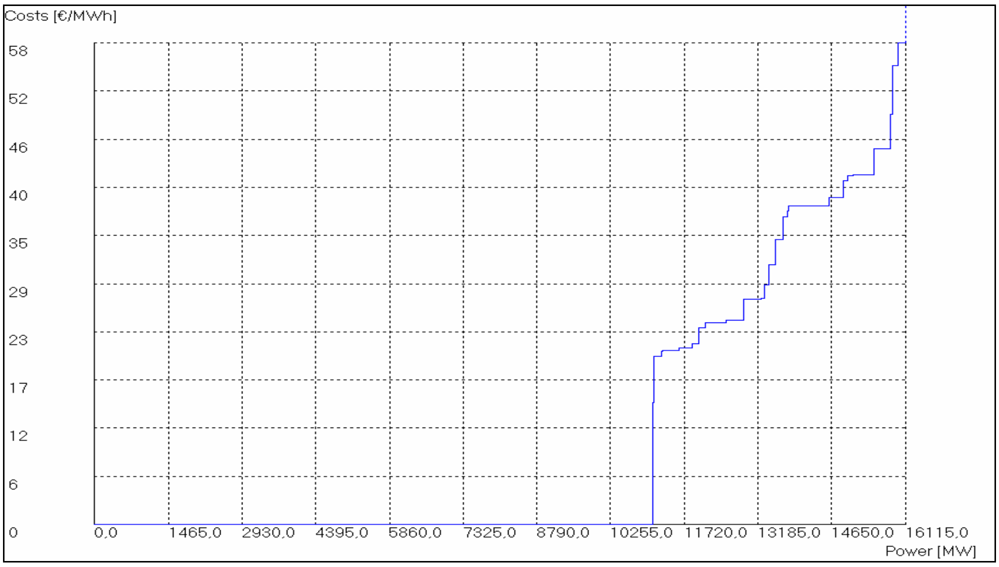


Figure 5.11: Theoretical supply curve[105] for Austria in 2010. The supply curve shown does not include the capacity of wind farms. Source: Own calculations[106]

[104] Source: /34/

[105] Note: The shown supply curve is a hardcopy of the software tool “NESoDSM” with German comma settings.

[106] In chapter 1.1 a figure is given which indicates decommissioned capacities for Austria of 365MW till the year 2010. These decommissioned plants are not considered in the investigations of the supply curve for 2010. A less capacity of 365MW would increase the lack in supply and support DSM-programs even more.

6 The computer model

The developed simulation tool calculates the in Chapter 3 derived economically and mathematically relations. All in chapter 3 described cases are examined now. The program is set up to import the necessary data from Excel. To obtain a user-friendly program the tool has been developed in Visual Basic 6 by the author of this work. Furthermore, regarding to future changes in the structure and enhancements the program has been developed in a very modular structure.

To minimize the time for the data import the program allows importing the necessary spot market price, national supply curve, elastic long term demand curve, transmission costs and subsidies from Excel. Because of the fact that the simulation tool calculates the economical parameters on an hourly basis the national supply curve and long term curve is required. Therefore, the data import tool from Excel is an important feature of the program.

In the next chapter a rough description of the simulation algorithm is given. Most of the description focus on model 1 ($C_T = 0$) only. Because of the complexity of the algorithm of model 2 only the differences to model 1 are explained. Therefore, no detailed algorithm for model 2 is shown.

6.1 Program structure

6.1.1 Overview

As a first step the data imported from Excel must be set up in a way that the simulation tool can work with it. The program does not save each point of the supply and demand curve on the hard disk because this process would waste storage and time. A "normal" Austrian supply curve consists of approximately 12,000 data points. Therefore, only the width of a certain price level [€/MWh] is saved (The program saves the data as blocks). This procedure reduces the necessary data point for a normal Austrian supply curve to 70 data points. However, in order to obtain a simple algorithm the supply and demand information must be transformed into a "continuous" form with 1MW steps.

num	power[MW]	costs[€/MWh]	CO2_emission[t/MWh]	type
1	4954	00.00	00.00	Run-of-River plants
2	6143	00.00	00.00	Storage power plants
3	14	10.59	00.31	HKW_Salzburg_Nord
4	14	15.11	00.26	HKW_St._Pölten_Nord
5	3	15.20	00.24	HKW_Salzburg_West
6	3	16.22	00.35	MHKW_Rottenmann
7	5	16.37	00.28	FHKW_St._Pölten_Süd
8	12	18.68	00.26	FHKW_Kirchdorf
9	350	19.61	00.56	Donaustadt_3
10	3	19.86	00.25	FHKW_Mödling
11	165	20.17	00.89	Riedersbach_II
12	246	20.22	00.57	FHKW_Mellach
13	330	20.87	00.96	Voitsberg_3
14	28	20.93	00.38	FHKW_Klagenfurt
.				
.				
.				

Table 6.1: Example for an Austrian supply curve saved on hard disk

The program considers two demand curves. The "original" demand curve without subsidies and the demand curve including subsidies. However, the consideration of variable subsidies in the demand curve leads to the problem that the merit order list of the demand curve may change. Therefore, a new merit order list for the demand curve considering subsidies must be obtained.

Next, the differentiation between the two basic models is made.

One of the most important procedure in the program is to find the intersection point between supply and demand. A detailed description for this procedure is given in chapter 6.1.3. After finding the intersection point between the demand curve (with subsidies) and supply curve the economical parameters can be calculated. For the model with transmission costs greater than zero ($C_T>0$) a sub case exists (see also chapter 3.2.4.1).

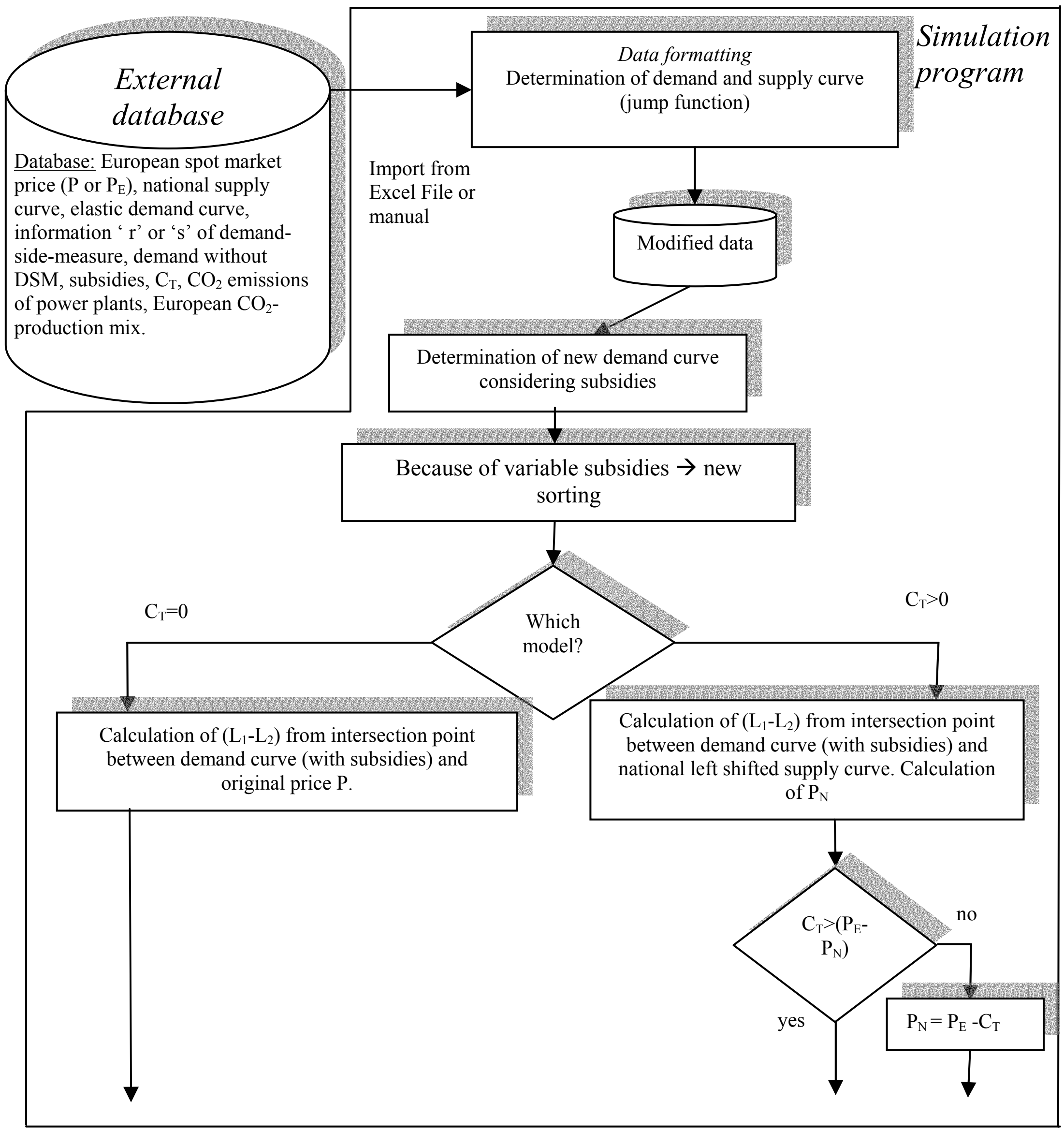


Figure 6.1: Principle structure of the simulation tool “NESoDSM”, part one

The next step is to calculate the DS-measures related reduction in CO_2 emissions. In principle the two basic models (C_T=0 and C_T>0) are very different concerning the calculation of the related CO_2 emissions.
For the first model (C_T =0) because of the export of power and reduction of demand elsewhere in Europe, no relation ship between a certain DS-measure and power plant can be observed.

Therefore, only an average European CO_2 factor for the calculation of the CO_2 reduction can be used. In the second model 2a ($C_T>0$ and $C_T>P_E-P_N$) a principle relationship[107] between a DS-measure and a not used power plant (and the respective CO_2 emission) in Austria is investigated. (For detailed information see chapter 6.1.6)

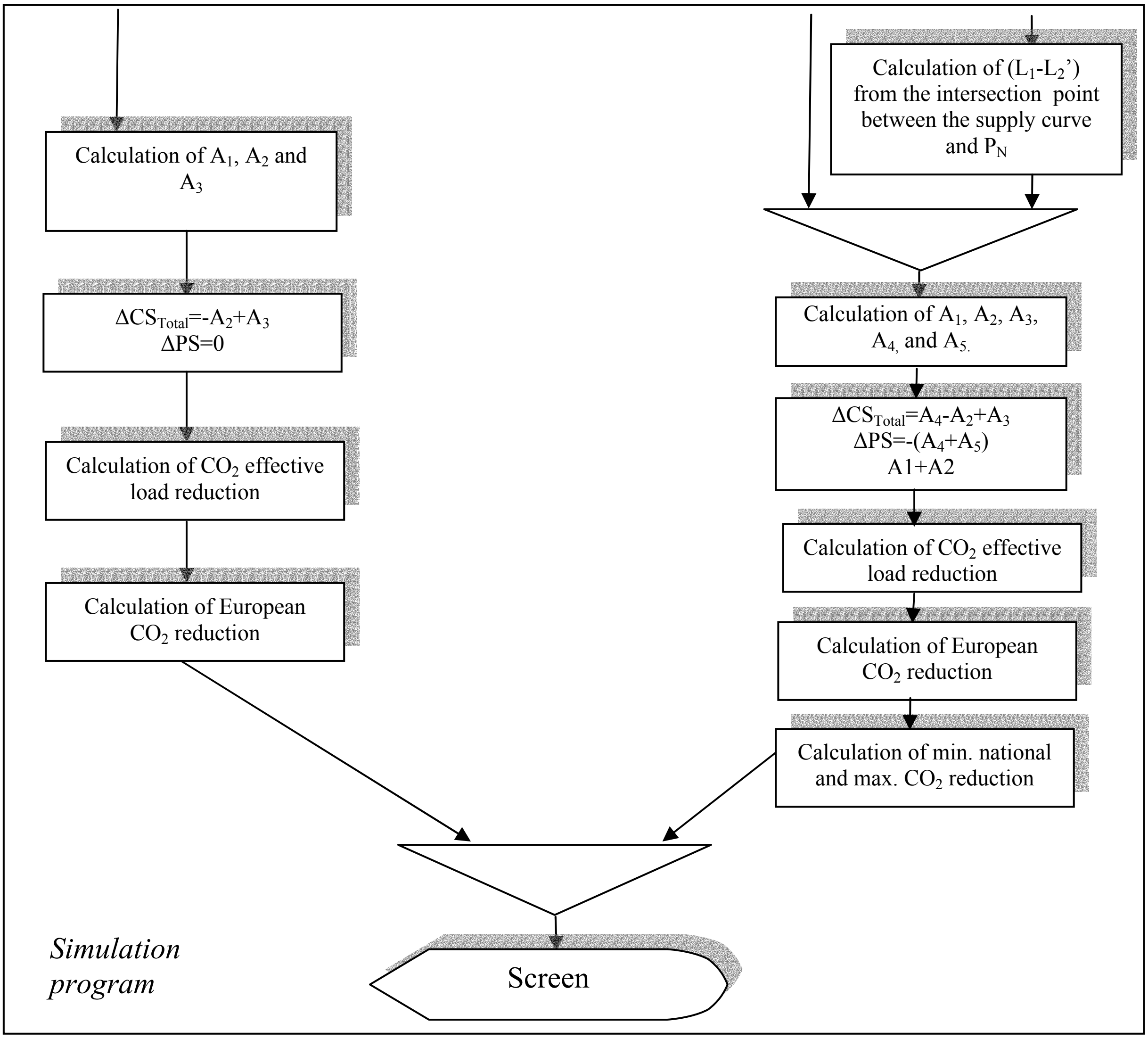


Figure 6.2: Principle structure of the simulation tool "NESoDSM", part two

[107] To find this relationship is not an easy process. In Principle more than on power plant can be used to decrease the CO_2 emissions. For example only 10MW DSM-measures reduce CO_2 emissions and e.g. two power plants with 50MW and different CO_2 emission rates are reduced. Which power plant is counted for the CO_2 reduction? Therefore, two different CO_2 reduction values are possible. See also chapter 6.1.6.2

6.1.2 Supply and demand structure used within the tool

As mentioned before the program does not store the full demand and supply curve on disk, only the capacity and the price levels are stored. However, inside the model the program needs a "continuous" demand and supply curve. The algorithm has to create a merit order list of different blocks and determines a supply and demand curve in one MW steps.
Therefore, three different arrays have to be defined to describe the supply and demand curves. Each array saves two values - a lower and upper value - for a certain index. The index indicates the power in one MW steps. If there is no step in the function the upper and lower point are equal. If there is a jump the upper value is greater than the lower value. This approach is very memory intensive but enables a simple algorithm.

Dim ArrayOriginalDemand(DemandIndex)(2) as double
Dim ArrayDemand(DemandIndex) (2) as double
Dim ArraySupply(SupplyIndex)(2) as double

DemandIndex	Number of step points (in one MW steps) necessary to describe the demand curve
SupplyIndex	Number of step points (in one MW steps) necessary to describe the supply curve (e.g. 12,000 for Austria)

	Index								
	1	2	3	4	5	6	7	8	9
Lower value	10	10	10	10	20	20	20	30	30
Upper value	10	10	10	20	20	20	30	30	30

Table 6.2: Example for a supply curve described in the program

For example, the supply curve jumps from 10€/MWh to 20€/MWh at 4MW (index = 4). A demand of 3.99MW leads to marginal costs of 10€/MWh and a demand of 4MW leads to marginal costs of 20€/MWh.

6.1.3 Calculation of intersection points between supply and demand

6.1.3.1 General point of view

The supply and demand curves used in this program are step functions. However, the utilization of step functions lead to the problem of finding a valid intersection point in the vertical part of the supply curve (in the jump) and the horizontal part of the demand curve. Such a intersection point does not fix the price and demand (= achieved DS-measure). To avoid this problem a definition of the valid intersection point is a necessity.

Firstly, a definition of the initial intersection point (L_1 and exogenous price) is necessary: As known from chapter 3 the exogenous spot market price and the original demand without DSM fix the demand curve without subsidies (red curve in Figure 6.3). This means that the supply curve has to be shifted left[108] in order to achieve an intersection point of demand and exogenous international price p ($P_T = P_E + C_T$ respectively).

[108] The supply curve is shifted only left. This means that the available capacity of the (hydro) power plants is reduced. If the supply curve does not match the original demand an error message is created and the user gets an order to insert additional capacity to match the original demand.

The initial intersection point between the original demand without DSM-measures (fully inelastic) and the supply curve is in the step of the supply (blue curve in Figure 6.3) and demand (red) curve. This means that the marginal power plant runs with full capacity and only one more unit of demand would lead to a jump to the next plant. Also, the marginal DS-measure is fully achieved.

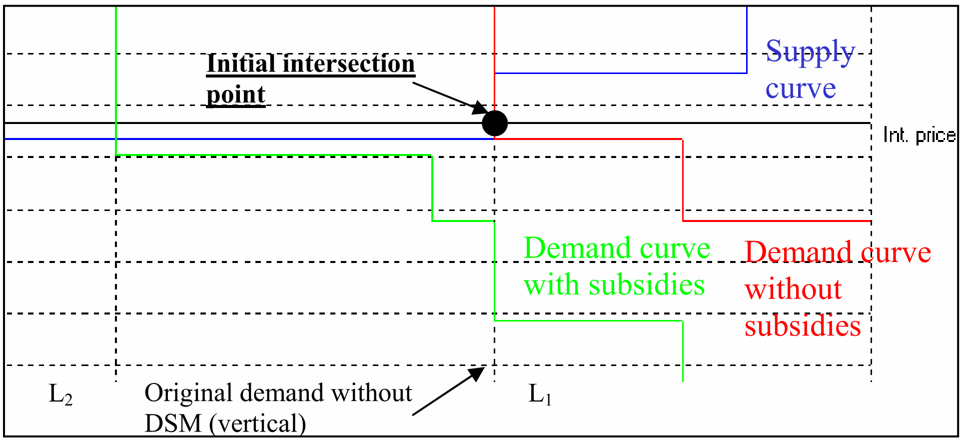


Figure 6.3: Definition of the initial intersection point between supply and demand

It needs to be pointed out concerning to the demand curve with subsidies (green) that after subtracting the subsidies from the original (red) elastic demand curve (generating the new demand curve) a demand-side-measure may not be fully achieved (see Figure 6.4). Therefore, initial shifting to the left of the elastic demand curve considering subsidies is necessary.

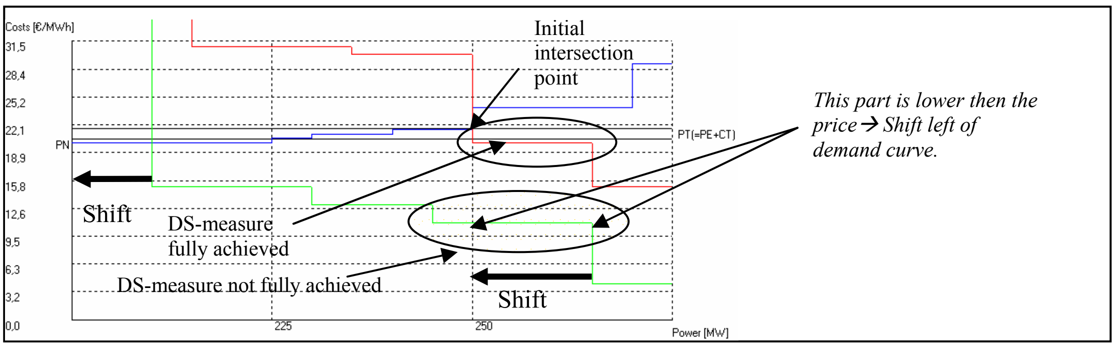


Figure 6.4: Possible initial shifting to the left of new demand curve with subsidies

Concerning to the new intersection point between supply (blue) and demand (green) the following assumption can be made: The new intersection point between demand with subsidies and supply is only allowed in the vertical part of the demand curve (green) and horizontal part of the supply curve (blue). In this point the marginal DS-measure is fully achieved and the marginal power plant runs only partly. However, this definition is only valid for model 1 and model 2a. For the extension (case 2b) of the second model with $C_T<P_E-P_N$, as described in chapter 3.2.4.1, the national market price has to be fixed to P_E-C_T. Therefore, the new intersection point is assumed to be in the step of the supply curve. This means that the marginal DS-measure is not fully achieved.

In the following the detailed algorithm to find the new intersection point for the model 1 ($C_T = 0$) is shown.

6.1.3.2 Model 1 (C_T=0)

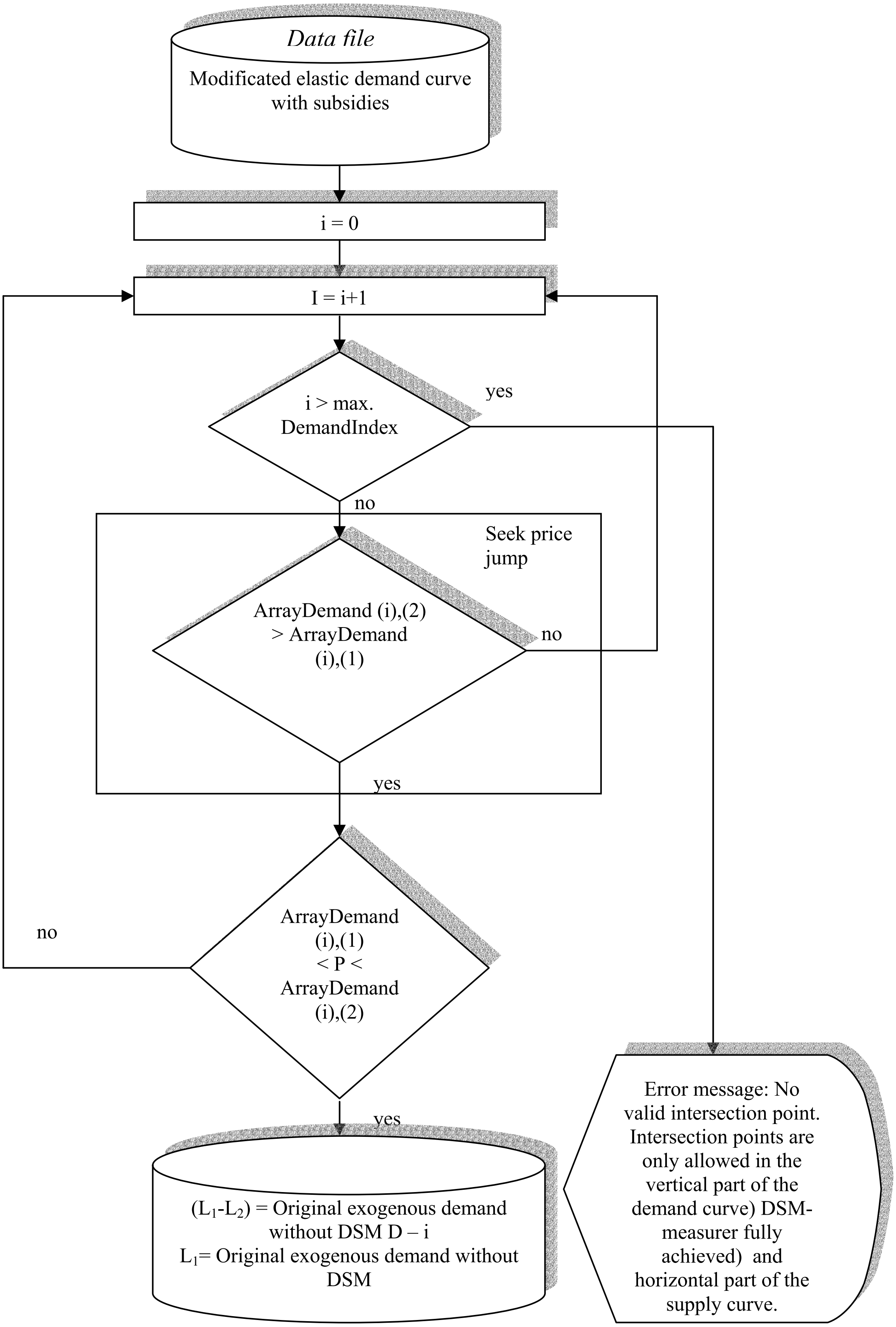


Figure 6.5: Algorithm to calculate the "fictive" demand reduction for model 1 (C_T = 0)

The calculation of the new intersection point for model 2 is not as simple like as model 1. The market price is not fixed to the exogenous price and secondly the model 2 is subdivided into case 2a and 2b. The algorithm calculates an intersection point and checks the new calculate price if the condition $C_T > P_E + P_N$ is violated. If the condition is violated a market price is assumed and with this new market price the load reduction is calculated (case 2b). The detailed algorithm for the gradual determination of the new intersection point for model 2 is shown in chapter A.3.

6.1.4 Calculation of economical parameters

6.1.4.1 National economics expenditures (A_1+A_2) for model 1 and model 2

The calculation of $A_1 + A_2$ is very simple. As already described in chapter 3.2.3 each point of the subsidized demand curve and the regarding subsidy between L_1 and L_2 is summed up to A_1+A_2 based on the utilization of the subsidized demand curve. Because of the different subsidies a new merit order list of the subsidized demand curve is necessary (see also chapter 6.1.3.1). Therefore, the DS-measures regarding to the original demand curve without subsidies may not be the same as the DS-measures actually used in the subsidized demand curve between L_1 and L_2.

$$A_1 + A_2 = \sum_{x=L_2}^{L_1} (subsidized\ demand\ curve_x + subsidy_x) \qquad \textbf{(6.1)}$$

The detailed algorithm is shown in chapter A.3. This procedure is also valid for model 2.

6.1.4.2 (A_1 + A_3) for model 1 and model 2

For model 1 (A_1 + A_3) can be easily calculated with the exogenous fixed market price and (L_1-L_2).

$$A_1 + A_3 = (L_1 - L_2) \times p \qquad \textbf{(6.2)}$$

For model 2 the multiplication has to be modified in that way that the price p has to be replaced by the total price $P_T = P_E + C_T$.

6.1.4.3 Subsidies per hour (A_2) model 1 and model 2

The area A_2 is the sum of all subsidies of all actually used DS-measures between L_2 and L_1. The detailed algorithm is shown in chapter A.3.

6.1.5 Gain from subsidies (A_3) for both models

From the calculations performed in the previous chapters (A_1+A_2), A_2, and (A_1+A_3) are already known. Therefore, A_1 and A_3 can be easily calculated:

$$\begin{aligned} c_1 &= A_1 + A_2 \\ c_2 &= A_2 \\ c_3 &= A_1 + A_3 \\ \Rightarrow A_3 &= c_3 - c_1 + c_2 \end{aligned} \quad \textbf{(6.3)}$$

c_1, c_2, c_3 already calculated in the program

6.1.5.1 A_4 and A_5 for model 2

- $\underline{A_4}$

The benefit of the price reduction (A_4) depends on L_2 and the difference (P_T-P_N) (see also chapter 3.2.4). Because of the assumed price for case 2b the calculation for case 2b is slightly different than for case 2a.

<u>case2a:</u>

$$A_4 = L_2 \times (P_T - P_N) \quad \textbf{(6.4)}$$

<u>case2b:</u>

$$A_4 = L_2 \times (2C_T) \quad \textbf{(6.5)}$$

- $\underline{A_5}$

The algorithm for the calculation of A_5 is shown in appendix A.3.

6.1.5.2 Change in Consumer and producer surplus

With the determined areas A_1 to A_5 the change in producer and consumer surplus with respect to the equations in chapter 3.2 can be obtained.

6.1.6 Calculation of CO_2 reduction

6.1.6.1 Model 1 ($C_T = 0$)

As emphasized in chapter 3.2.3 the reduced Austrian load is exported to Europe. Assuming that the entire European demand is fixed, elsewhere in Europe the supply has to be reduced. However, no one knows which power plant has to reduce its production and no information about the CO_2 emissions of the regarding power plant exists. Therefore, only an average European emission rate can be assumed.

Additionally, also, the structure of the DS-measure is important. If the DSM-measures used in Austria are only shift measures no CO_2 reduction is achieved, because the shifted load is consumed during off-peak hours unfortunately. But the off-peak power plants and their CO_2 emissions are unknown. Therefore, the average emission rate for off-peak hours is assumed to be equal to the average emission rate during on-peak hours.
The average CO_2 reduction is calculated with all reduction DSM-measures between the new demand (L_2), the original exogenous demand (L_1) and the average European CO_2 emission rate [tCO_2/MWh].

$$\Delta CO_{2\,Europe} = \overline{EmissionRate}_{CO_2 Europe} \times \sum_{x=1}^{n} P_{DSM\,x} \times i_x \times j_x \quad [tCO_2 / h]$$
$$i_x = 1 \; for \; 'r', \; i_x = 0 \; for \; 's'; \;\; j_x = 1 \; for \; P_{DSM\,x} \; between \; L_2 \; and \; L_1 \qquad \textbf{(6.6)}$$
$$(r = load\,reduction, \; s = load\,shifting)$$
$$n \ldots total \; number \; of DSM - measures$$

6.1.6.2 Model 2 – case 2a (C_T>0 and C_T<P_E-P_N)

As a first step the CO_2 effective load reduction has to be calculated. In this case only DSM-measures which are "load reduction" measures between L_2 and L_1 are considered for a CO_2 reduction.

$$\Delta P_{CO2\,Effective} = \sum_{x=1}^{n} P_{DSM_x} \times i_x \times j_x \quad [MW]$$
$$i_x = 1 \; for \; 'r', i_x = 0 \; for \; 's'; \; j_x = 1 \; for \; P_{DSM\,x} \; between \; L_2 \; and \; L_1, \; j = 0 \; for \; all \; others$$
$$P_{DSM_x} \ldots Load \; reduction \; caused \; by \; DSM - measure \; x \qquad \textbf{(6.7)}$$
$$n \ldots total \; number \; of \; DSM - measures$$
$$(r = load\,reduction, \; s = load\,shifting)$$

Because of existing transmission costs the load reduction is not exported to Europe and the Austrian supply is decreased. For each power plant the CO_2 emissions are stored in the project database. With the CO_2 effective load reduction the Austrian CO_2 reduction can be calculated. However, one problem exists. Which DSM-measure eliminates which power plant? This problem is very difficult to solve because no linkage between a certain DSM-measure and power plants exists. Therefore, two extreme values for the Austrian CO_2 reduction are possible.

- Maximum CO_2 reduction

  A merit order list depending on the CO_2 emission of all reduced power plants was set up. Starting with the plant with the highest emission rate the Austrian CO_2 reduction has been calculated. For each power plant the emission rate is multiplied with the capacity of the plant. All these products are summed up till the CO_2 effective load is reached.

$$\Delta CO_{2\max} = \sum_{j=1}^{k} \max.sorted[CO_2 Emissions_j] \times P_{Plant_j} \; [tCO_2 / h]$$
$$k = f(\Delta P_{C02Eeffective})$$
$$\max.sorted[CO_2 Emissions_j] \ldots power\ plants\ merit\ order\ depending$$
$$on\ CO_2\ emissions \tag{6.8}$$
$$P_{Plant_j} \ldots power\ of\ power\ plant\ j$$
$$P_{Plant_{j=x}} = Modificated\ power\ of\ plant\ j = x$$
$$CO_2 Emissions_j \ldots CO_2\ emissions\ of\ plant\ j\ [tCO_2 / MWh]$$

As emphasized in chapter 6.1.3.1 the new intersection point is always in the vertical part of the demand curve and the horizontal part of the supply curve (for model 1 and model 2a). The marginal power plant does not operate with full power. Therefore, the marginal power ($P_{Plantj=x}$) plant capacity has to be modified.

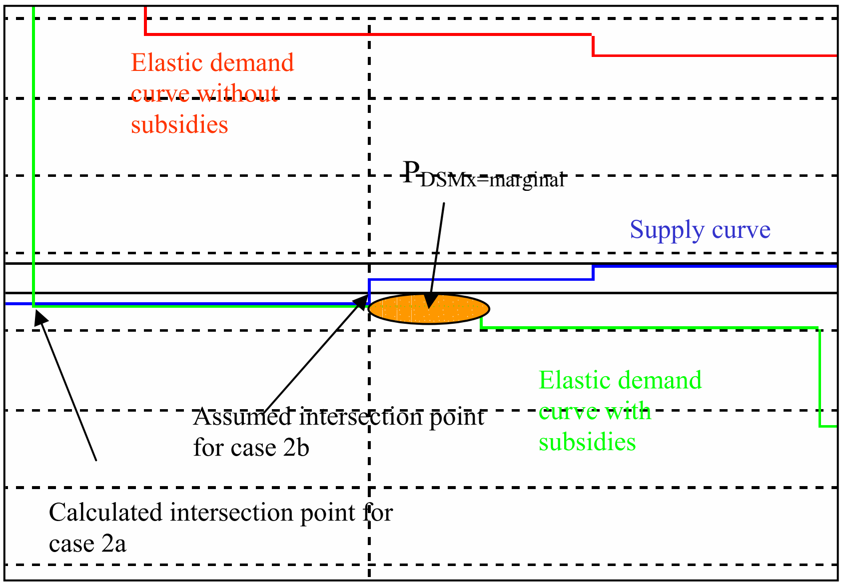
- Minimum CO_2 reduction

A merit order list depending on the CO_2 emission of all reduced power plants was set up. Starting with the plant with lowest emission rate the Austrian CO_2 reduction is calculated. For each power plant the emission rate is multiplied with the capacity of the plant. All these products are summed up till the CO_2 effective load is reached.

$$\Delta CO_{2\max} = \sum_{j=1}^{k} \min.sorted[CO_2 Emissions_j] \times P_{Plant_j} \; [tCO_2 / h]$$
$$k = f(\Delta P_{C0_{2Effective}})$$
$$\min.sorted[CO_2 Emissions_j] \ldots power\ plants\ invers\ merit\ order$$
$$depending\ on\ CO_2\ emissions \tag{6.9}$$
$$P_{Plant_j} \ldots power\ of\ power\ plant\ j$$
$$P_{Plant_{j=x}} = modificated\ power\ of\ plant\ j = x$$
$$COEmissions_j \ldots CO_2\ emissions\ of\ plant\ j\ [tCO_2 / MWh]$$

6.1.6.3 Model 2 - case 2b (C_T>0 and P_N=P_E-C_T)

For the extended model 2b the new assumed intersection point is always in the vertical part of the supply curve and in the horizontal part of the demand curve. Therefore, the new marginal demand-side-measure is not fully achieved. Therefore, a modification of the load reduction ($P_{DSMx=marginal}$) for the marginal DS-measure is necessary.



Nevertheless no modification of the new marginal power plant is necessary ($P_{Plantj=x}$).

Figure 6.6: Assumed new intersection point for model 2b and not fully achieved marginal DS-measure

6.2 Boundaries of the shown algorithm

The algorithm is not able to recognize combined heat and power (CHP) plants. However, an imperative for the heat production is the electricity production. The CHP-plant must run to produce "waste" heat for heating systems. Perhaps, the algorithm eliminates a CHP-power plant because of DS-measures. But, due to the heat boundary it must run. Because of this restriction the calculated CO_2 reduction is higher than the real CO_2 reduction.

7 The software tool "NESoDSM"

7.1 General point of view

The Software tool "NESoDSM" was developed in Visual Basic 6 and is supported by the operating system WinNT4, Win2000 and WinXP. The tool supports most of the Microsoft defined standards, like shortcuts (e.g. STRG + S for Save, STRG + C for copy, STRG + O for open project, and…) and help files. A short outline about the most important features which are necessary in order to operate the program in the following chapters are described.

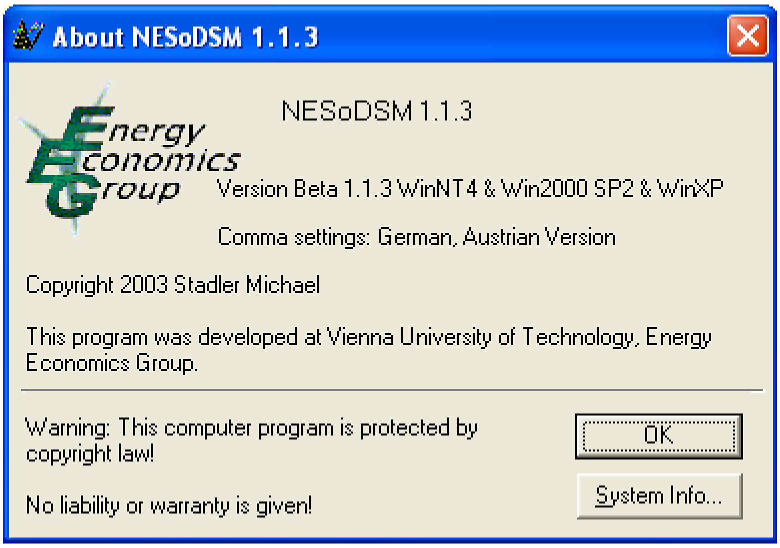


Figure 7.1: The software tool "NESoDSM"

7.2 Input form

In the following input form all necessary data for the simulation are combined. On the left hand side on the top the original demand without DSM, the exogenous international electricity price, the cost for transmission and the average European CO_2 emission value are gathered. These values can be easily changed. Clicking on an item and changing the value in "Actual value" and hitting "Apply" makes the new value(s) effective.
Below these exogenous parameters the supply and demand curve are located. Before it is possible to insert or edit data it is necessary to select either the "Supply curve" or "Demand curve". The grid is designed to work in the same way as Excel. After selecting "Supply curve" or "Demand curve" it is possible to copy and paste values from Excel into this input grid. The program is designed in that way that it is possible to export data to Excel. All necessary comments can be found in "Edit" or directly accessed by the Microsoft standard shortcuts. Please, note that in order to work with the "Edit" comments it is necessary to select the grid first by clicking on any cell in the grid.
Hit always the responsible "Apply" button to make the changes effective. The responsible "Apply" button is always located in the same frame as the changed item. On the right hand side either the supply curve or demand curve is shown. By clicking on "Switch to data grid view" the merit order list of either the supply curve or demand curve is shown in a data grid form.

On the right hand side on the top one of the two basic models can be selected. The first option “International Spot market price = national spot market price” is equal to model 1 (C_T=0) from chapter 3.2.3. The second option refers to the second basic model with C_T>0. The differentiation between case 2a and case 2b (see also chapter 3.2.4 and chapter 3.2.4.1) is followed automatically by the model itself.

If all necessary data is entered and valid the program releases the “Run” button. Now, simulations can be performed.

Note, that there is a difference between “Apply” and “Save”. “Apply” only updates the data in the memory so that the algorithm can use the changed values, but if the program gets closed all changes are lost. If it is necessary to store the changed data permanently the project has to be save by using STRG +S.

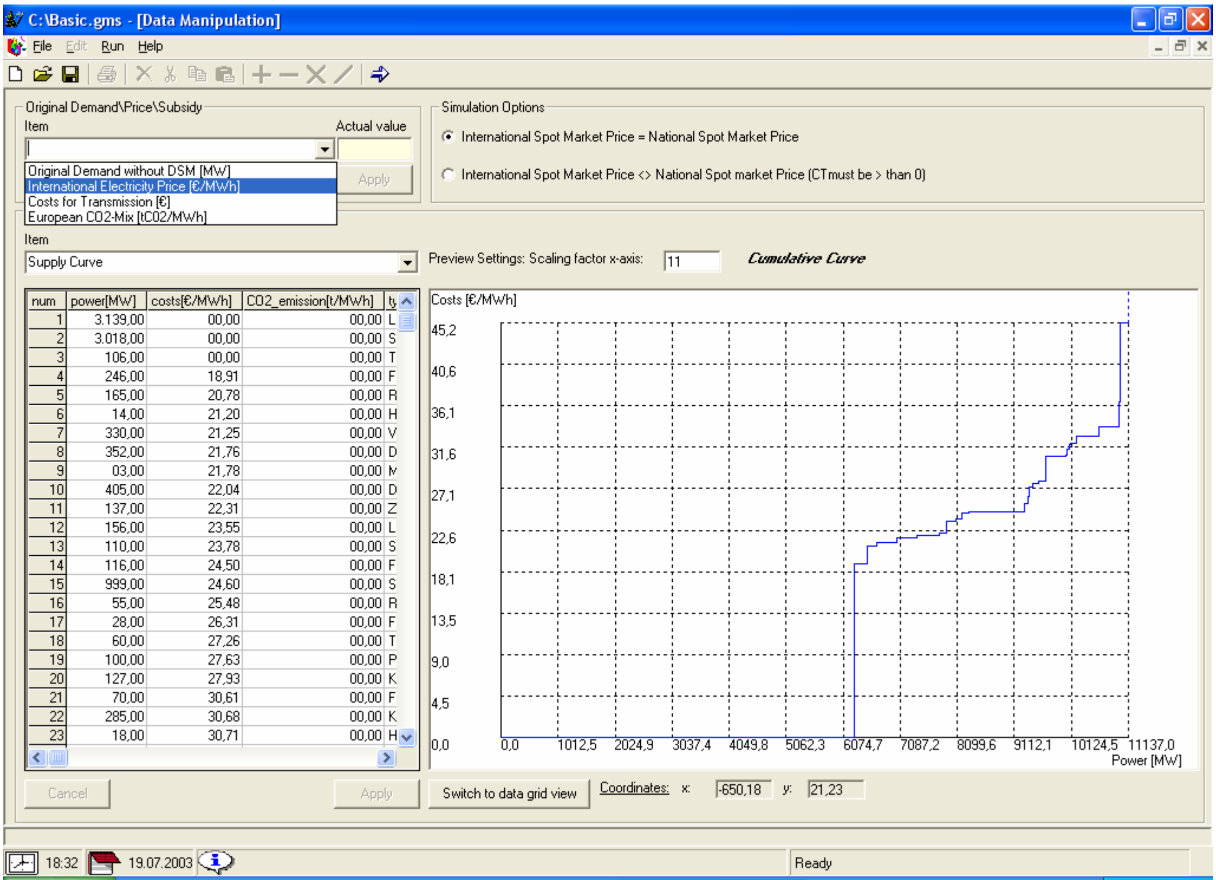


Figure 7.2: Exemplary input form of “NESoDSM”. Note: German comma settings

7.3 *Output form*

The output forms for the two different models differ slightly. Therefore, each output form is described separately. The output forms can be shown in graphic or text mode. By clicking on “Switch to text view” the output form switches to the text mode.

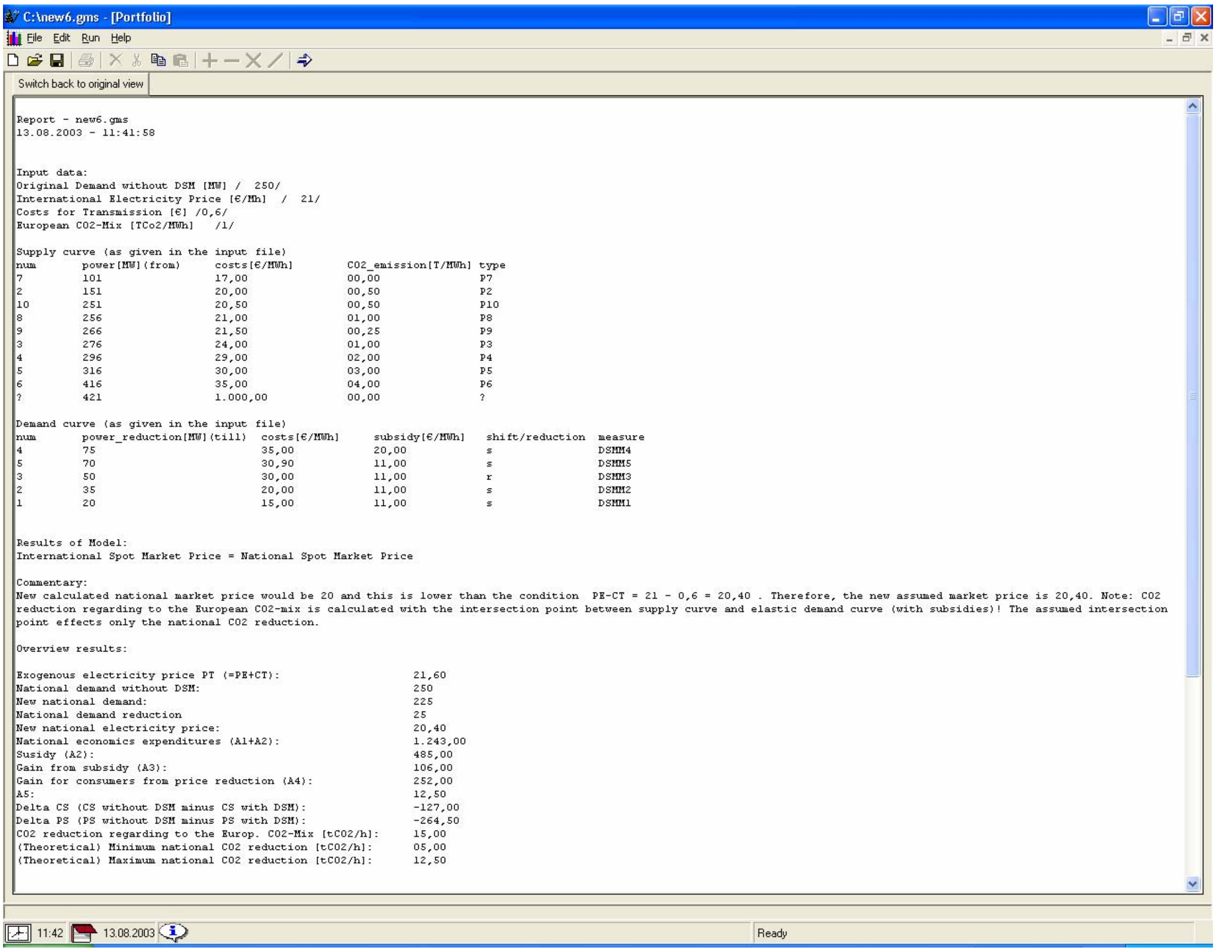


Figure 7.3: Output form[109] in text mode[110]

At the top of the text form all exogenous parameters as well as the supply curve and demand curve are shown. After the input data the selected model and any comments are placed. The last part of this textual form is the result component of the simulation. The actual version[111] does not support printing, but this is not a big restriction. It is possible to select all (or parts of the text) by clicking in the text area and selecting all with STRG + A or parts of the text with the mouse. After selecting the respective parts the selected data can be copied to an other application (e.g. Word) by using STRG + C.

[109] With German comma settings

[110] Figures given in this chapter are only examples for calculations. The derived values shown in the figures do not have any practical relevance.

[111] Version 1.1.3

7.3.1 Output form for model 1 (C_T =0)

The given output form shows the results for an exemplary simulation of model 1. As known from chapter 3.2.3 no A_4 (gain from price reduction) and A_5 values for model 1 can be obtained. Furthermore, no maximal and minimal national CO_2 reduction is predictable (see also 6.1.6.1). Therefore, these areas are disabled.

All values which are given by the input data are in grey cells. In contrast, all values resulting from the simulation are placed in yellow cells. In the case with C_T = 0 the new national electricity price is fixed by the exogenous international electricity price and the change in producer surplus is always zero. Hence, these cells are grey.

On the right side any comments or warnings produced by the program are shown. Below the red text box information about power plants and DS-measures are given.

The graphical illustration of the supply and demand situation in a certain hour can be easily copied into Word, or a graphical program (e.g. Paint). Firstly, the figure has to be selected by clicking in the figure. Next, the figure can be copied to the clipboard by using the shortcut STRG + C or by clicking on the copy symbol in the tool bar on the top of the form.

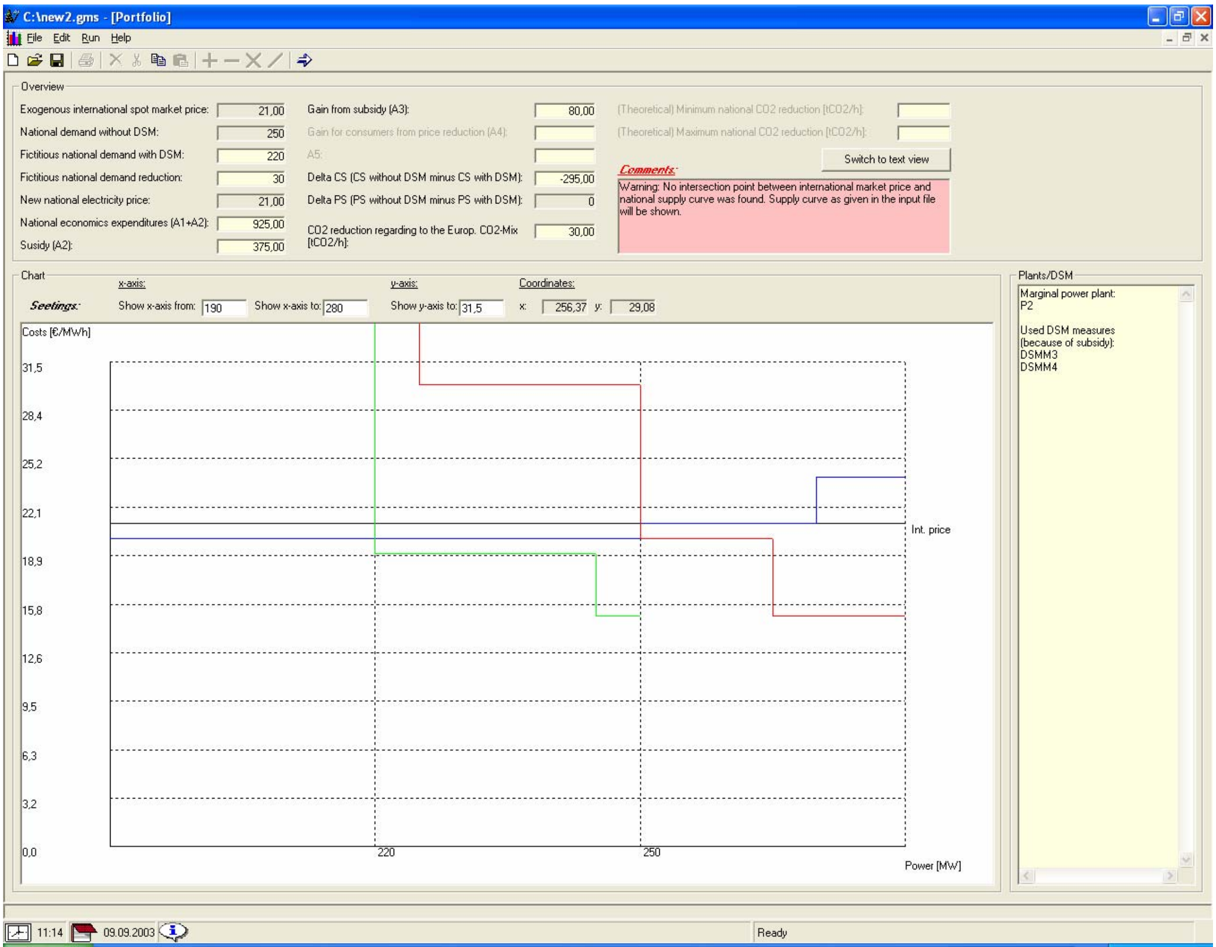


Figure 7.4: Output form[112] for model 1

[112] With German comma settings

Now, the graphic can be inserted into Word or an other program by using STRG + V.

7.3.2 Output form for model 2 (C_T>0)

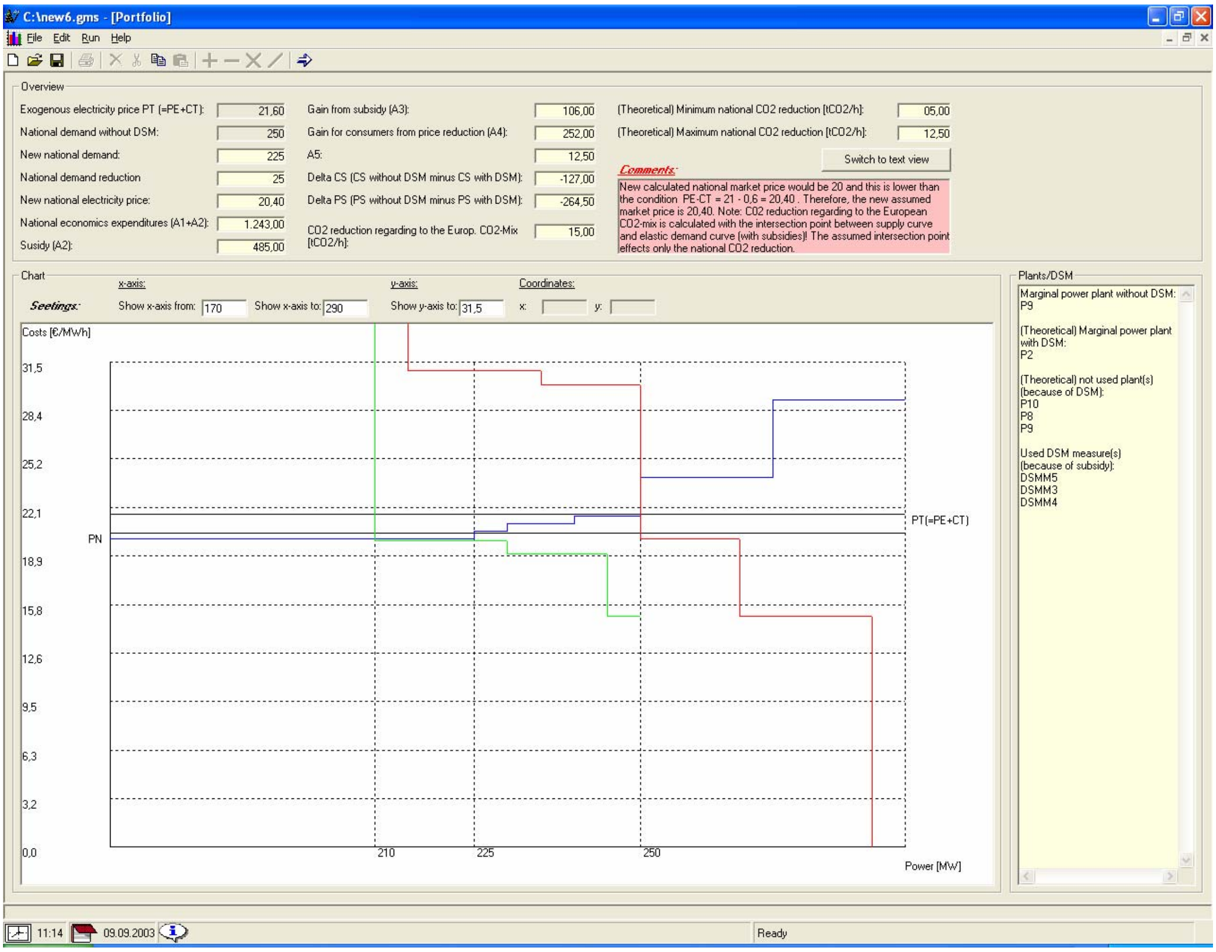


Figure 7.5: Output form[113] for model 2

In contrast to model 1 for model 2 the “New electricity price”, A_4, A_5, Delta PS, the maximal and minimal nation CO_2 reduction are derived from the calculations and therefore written in yellow cells. As mentioned before, the algorithm switches automatically between case 2a and case 2b. If the model assumes a new national market price with regard to case 2b a corresponding comment is given in the red text box.

For model 2 the graphical illustration can also be copied to an other program (e.g. Word) as described in chapter 7.3.1.

[113] German comma settings

8 Results of the sensitivity analyses for winter months with the software tool "NESoDSM"

8.1 Determination of necessary subsidized long term demand curve

For the scenario analyses is this chapter the subsidized long term demand curve is necessary. With the equations from chapter 4.7 the application prices depending on investment subsidies for the alternative high efficient devices can be calculated.

Electrical cooking devices, dish washers, washing machines and driers are combined to the process heat appliances as emphasized in chapter 4.6.5. Hence, only one average application price (tariff) for all these devices is considered. Because of missing information about the detailed composition of all heat appliances only an approximated value of the application price depending on the investment subsidy can be calculated. The investment costs for alternative and basic heat appliances are assumed to be 829€ and 350€. With these assumptions and Table 4.14 an average reduction of the application price depending on the share of investment subsidy can be determined.

DS-measure	Attractive spot market price (application price) without investment subsidy [€/MWh]	Application price [€/MWh] with investment cost subsidy in [%]				
		10%	20%	30%	40%	50%
20W high efficiency bulb instead of 100W bulb	32.7	29.23	25.80	22.36	18.92	15.48
11W high efficiency bulb instead of 60W bulb	39.0	34.84	30.71	26.58	22.45	18.32
Process heat	42	34.92	27.84	20.76	13.69	6.61
Class A freezer	25.1	18.01	10.9	3.79	<0	<0
Class A refrigerator	22.1	14.73	7.38	0	<0	<0
17" TFT monitor	45.5	33.77	21.90	10.03	<0	<0

Figure 8.1: Determination of subsidized long term demand curve

Low investment subsidies of only 20% or 30% reduce the application price considerable. E.g. a 30% investment subsidy for process heat appliances results in a 50% reduction of the application price. All appliances considered to be changed in this work need not to be subsidized with more than 30% of the investment costs to become cheaper than the current on-peak market price of 28.48€/MWh[114].

According to the used data, in Austria most of the customers use high efficient class A freezers and class A refrigerators instead of class C devices. The application price for freezers and refrigerators is lower than the on-peak market price of 28.48€/MWh. In 1998, the average

[114] Average on-peak price for Germany in 2002

sales market share for high[115] efficient refrigerators and freezers was 60% (see /1/). For 2002 a sales market share of more than 70% is estimated. Nevertheless, refrigerators and freezers are operating 24 hours a day and therefore, the average base market price of 24.15€/MWh for Austria is decisive. Furthermore, no TOU tariffs or RTP are available in Austria. As a result of these reflections every residential customers only recognizes the 24.15€/MWh market price instead of the 28.48€/MWh. The charged flat tariff of 11€c/kWh (which represents the market price transformed in tariffs, see also 4.7.3) is slightly higher than the application tariff of class A refrigerators (= 10€c/kWh) and slightly lower than the application tariff of class A freezers (= 11.4€c/kWh). These facts explain partly the achieved sales market share of 70% of high efficient freezers and refrigerators.

8.2 Low price scenario

8.2.1 General considerations

In this chapter a low price scenario is investigated. For all examinations the following exogenous parameters have been used:

- Low on-peak price of 28.46€/MWh (= average on-peak price for the year 2002)
- Supply curve based on fuel prices for the year 2001 (see also chapter 4.8)
- On-peak demand of 11GW
- No transmission congestion. That means, only transaction costs have to be considered. The transaction costs are fixed to 0.73€/MWh according to chapter 4.2.6. However, the 0.73€/MWh are only used for model 2. For model 1 the transaction costs are considered to be zero.
- Estimated average European CO_2 emissions during winter months of 0.44tCO_2/MWh[116]
- The subsidies are chosen individually for each appliance. The alternative appliance must be slightly cheaper than the reference price

As a result of the average on-peak price of 28.46€/MWh all class C freezers and class C refrigerators are replaced by class A devices without any subsidy.

To achieve a slightly lower application price than the according reference price of 28.46€/MWh the following investment subsidies have been applied:

- 20W high efficiency bulb instead of 100W bulb: 20% subsidy of investment costs
- 11W high efficiency bulb instead of 60W bulb: 30% subsidy of investment costs
- Process heat: 20% subsidy of investment costs
- 17" TFT monitor: 20% subsidy of investment costs

8.2.2 Model[117] 1 with $C_T = 0$

In model 1 no reduction in national market price happens. The achieved load reduction for on-peak hours is 247MW, but as already mentioned before this reduced load is exported to

[115] Class A and B

[116] Of course the average yearly European CO_2 emissions per MWh are lower than the average specific CO_2 emissions during winter months. The average yearly specific CO_2 emissions are 0.39tCO_2/MWh.

[117] Please note in this context "model" means the formal framework developed in chapter 3.

Europe. Therefore, the marginal power plant does not change. Hence, as a result of Austrian investments in DS-measures no supply related CO_2 reductions in Austria have been achieved. The corresponding European CO_2 reduction results into 109tCO_2/h. The entire expenditures of DS-measures are about 8,954€/h. The customers who invest in DS obtain a gain of 604€/h because of subsidies of 2,528€/h. Therefore, the change in consumer surplus is -1,924€/h. As emphasized in chapter 3.2.3 all costumers have to pay these investments in DS-measures. In contrast to the customers producers do not have any negative monetary effect. The change in producer surplus is zero.

However, the most important question is what are the costs for the community per year[118] in order to achieve a load reduction of 247MW? The question can be easily answered. As a result of the investment subsidy it is not important how frequently the new device is used. The usage time is already included in the application price. Once a decision for an alternative device is made the subsidy gets paid by the community. Therefore, the subsidy paid by the community can be calculated from the investment costs for the high efficient device, the share of investment subsidy for each appliance and the number of changed devices.

From Table 4.14 in chapter 4.7.4 the estimated equivalent total number of devices is known. These numbers have to be multiplied with the share of replaced devices (= 20%). For each appliance the investment subsidy is known from the previous chapter. The multiplication of investment costs[119] for each alternative device with the share of subsidy results in the subsidy per device. Afterwards, the specific subsidy has to be multiplied with the number of replaced devices. These calculations result in the total subsidy for all changed devices per year of €41m[120].
The division of the total subsidy per year by the total number of households[121] and companies[122] in Austria results in a monthly additional fee of 93€c/month[123]. Currently, the additional fee for stranded costs, CHP, and small hydro power in Austria is 1€/month (see also /43/).

Hence, to achieve a load reduction of 247MW during critical on-peak hours each customer in Austria has to pay 93€c/month. The total investments in DS-measures per year are €194m.

At this point a very important question appears. What would it cost to build a new on-peak thermal power plant with a capacity of 250MW to handle the imbalance of 250MW between supply and demand? With the estimation of specific turnkey costs of 600€/kW the total investment for a new 250MW thermal power plant results in €150m.

The total investments in high efficient devices are higher than then the total investment costs for a new thermal power plant. However, it needs to be pointed out that the investments in the new thermal power plant and the operation of this plant produce additional CO_2 emissions which make it more difficult for Austria to reach this Kyoto target. Therefore, the planed emission trading system makes it difficult for a supplier to get new certificates for additional

[118] Currently, the program does not support the calculation of characteristic values on a yearly basis. Originally, the tool was plant to investigate the load curve on an hourly basis only. However, investigations in this work have shown that yearly characteristic values are very useful. Therefore, future versions of the program will be able to calculate characteristic values on a yearly basis.
[119] From investigations based on /13/ the investment costs for the alternative average process heat appliance can be estimated with 829€.
[120] Without VAT
[121] 3.32 million households
[122] 351,041 companies in the year 2001. Source: www.statistik.at
[123] This calculated value does not include costs for money administration.

thermal power plants. In contrast to this approach the slightly higher investment costs in DS-measures reduce the CO_2 emissions.

Furthermore, only the investments in the new high efficient devices are higher than the investments in the new thermal plant. The investments in the same amount of inefficient devices would result in a total investment of €52m. This means that the investments in high efficient alternative devices result in additional costs of €142m only. The replacement of the old inefficient devices results in additional €142m[124]. This is less expensive than the construction of a new thermal power plant.

As a result of these investigations the two principle measures – DSM and production of electricity with a new additional thermal power plant – should be treated equal from a national economic point of view. Therefore, an independent regulator has to options to manage the imbalance between supply and demand:

- Enforce the construction of new (thermal) power plants and increase the CO_2 emissions or
- Enforce DSM-programs and hence, reduce CO_2 emissions

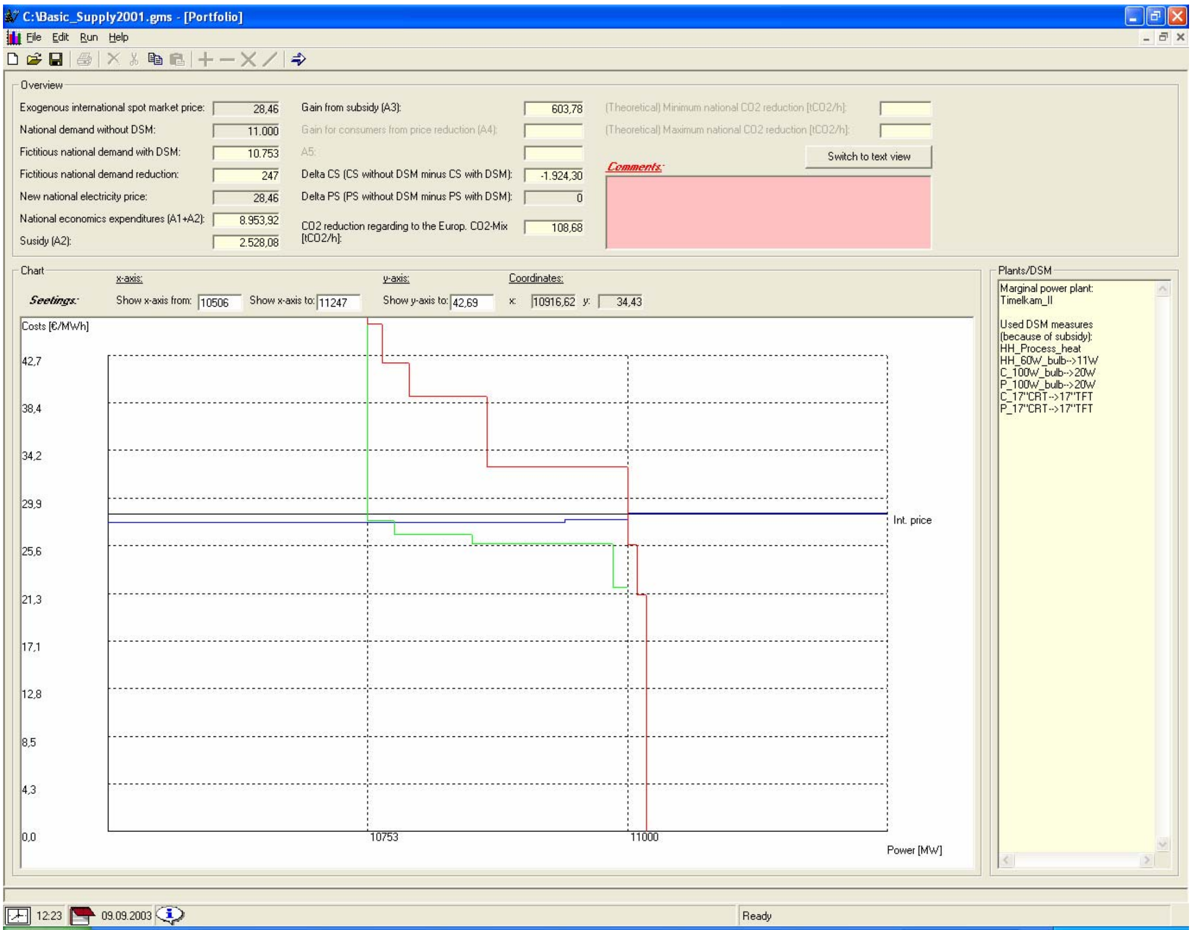


Figure 8.2: Graphical results[125] for model 1, low price scenario

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[124] This calculation assumes basic process heat appliance investment costs of 350€ per equivalent device.
[125] Note: The figure shown is a hardcopy of “NESoDSM” with German comma settings

8.2.3 Model 2 with C_T>0

Because of transaction costs of 0.73€/MWh the national market price is higher than in model 1. The exogenous fixed reference price is set to 29.19€/MWh. Because of these transaction costs the national market price obtained from the intersection point between supply and demand is variable within the price band of 0.73€/MWh. Because of considering transaction costs the new national market price obtained is 28.51€/MWh. This is equivalent to a 2.3% reduction in prices (wholesale price plus transmission costs).

Because of transaction costs and the resulting new intersection point between supply and demand the wholesale price is reduced by about 2.3%

The expenditures for DS-measures and subsidies for theses measures do not change compared to the model without transaction costs (C_T = 0). As a result of the decreased wholesale price in Austria the change (compared to the case without DS) in consumer surplus is 5,568€/h. Customers obtain a positive monetary gain because of this price reduction. In contrast to the customers producers earn less money compared to the case without DSM-measures. The change in the producer surplus results into -7,480€/h. Therefore, the national monetary gain is negative as explained in chapter 3.3.

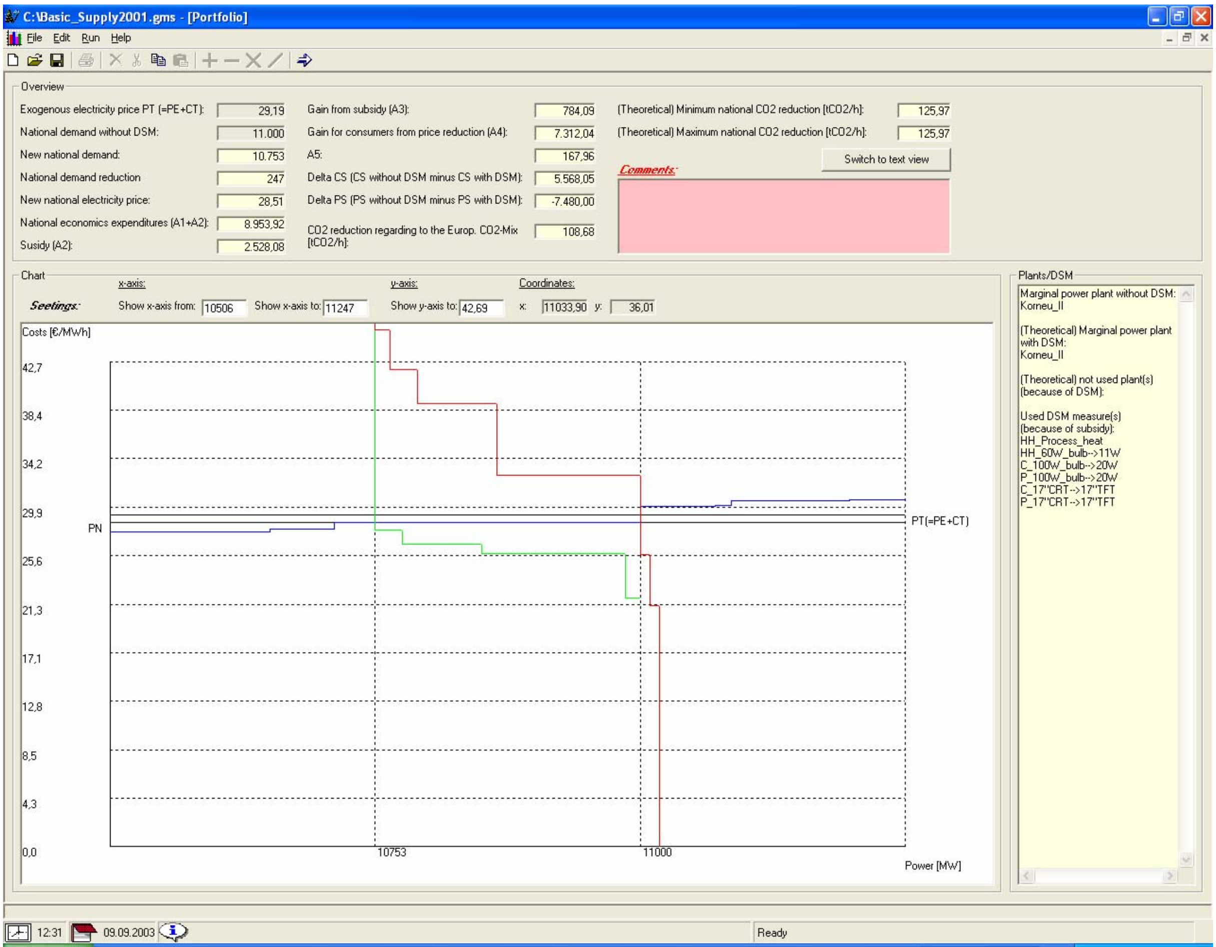

Figure 8.3: Graphical results[126] for model 2, low price scenario

[126] German comma settings

Again, the reduced load is 247MW, but this reduction in load reduces directly the supply in Austria. Therefore, the achieved reductions of CO_2 emissions can be directly counted for Austria. The marginal power plant does not change and therefore the achieved reduction in emission is exactly 125.97tCO_2/h.

8.3 Medium price scenario

8.3.1 General considerations

In this chapter a medium price scenario is investigated. For all examinations the following exogenous parameters have been used:

- Medium on-peak price of 38.23€/MWh
- On-peak demand of 11GW
- No transmission congestion. This means that only transaction costs have to be taken into account. The transaction costs are fixed to 0.73€/MWh according to chapter 4.2.6.
- Estimated average European CO_2 emissions during winter months of 0.44tCO_2/MWh.
- The subsidies are chosen individually for each appliance. The alternative appliance must be slightly cheaper than the according reference price.

To achieve a slightly lower application price than the according reference price of 38.96€/MWh (for model 2) a 10% investment subsidy for the following appliances has to be paid:

- 11W high efficiency bulb instead 60W bulb
- Process heat and
- 17"TFT monitor

Because of the higher reference price all other high efficient appliances (20W bulb, refrigerator and freezer) are already achieved.

8.3.2 Model 2 with C_T>0 based on supply curve for the year 2001

For the scenario performed in this chapter the supply curve based on fuel prices for the year 2001 (see also chapter 4.8) is used. This means that the higher market price of 38.23€/MWh is a result of lack in supply and not of high fuel prices

Because of the intersection point between the supply curve and the subsidized demand curve the new market price would decline from 38.96€/MWh to 32.73€/MWh. This is equivalent to a 16% decrease of the market price, whereas the reduction of 6.23€/MWh is much higher than the transaction costs of 0.73€/MWh. Therefore, foreign utilities have incentives to buy cheap Austrian electricity till the national market price rises up to 37.50€/MWh. As a result of these incentives <u>no</u> supply is reduced in Austria resulting in no national CO_2 reduction. The corresponding European CO_2 reduction is 49.72tCO_2/MWh.

The simulation with the software tool "NESoDSM" results in a national load reduction of 113MW. <u>This saving is exported to Europe.</u> The market price (wholesale price plus transmission costs) drops of about 3.7%. Because of the decrease in price the change in consumer surplus is positive. Nevertheless, the subsidies paid by the community are lower than they are for the low price scenario:

The necessary taxes for the support of DS-measures drop to €17m based on all Austrian customers and an additional fee of 39€c/month for each customer is necessary.

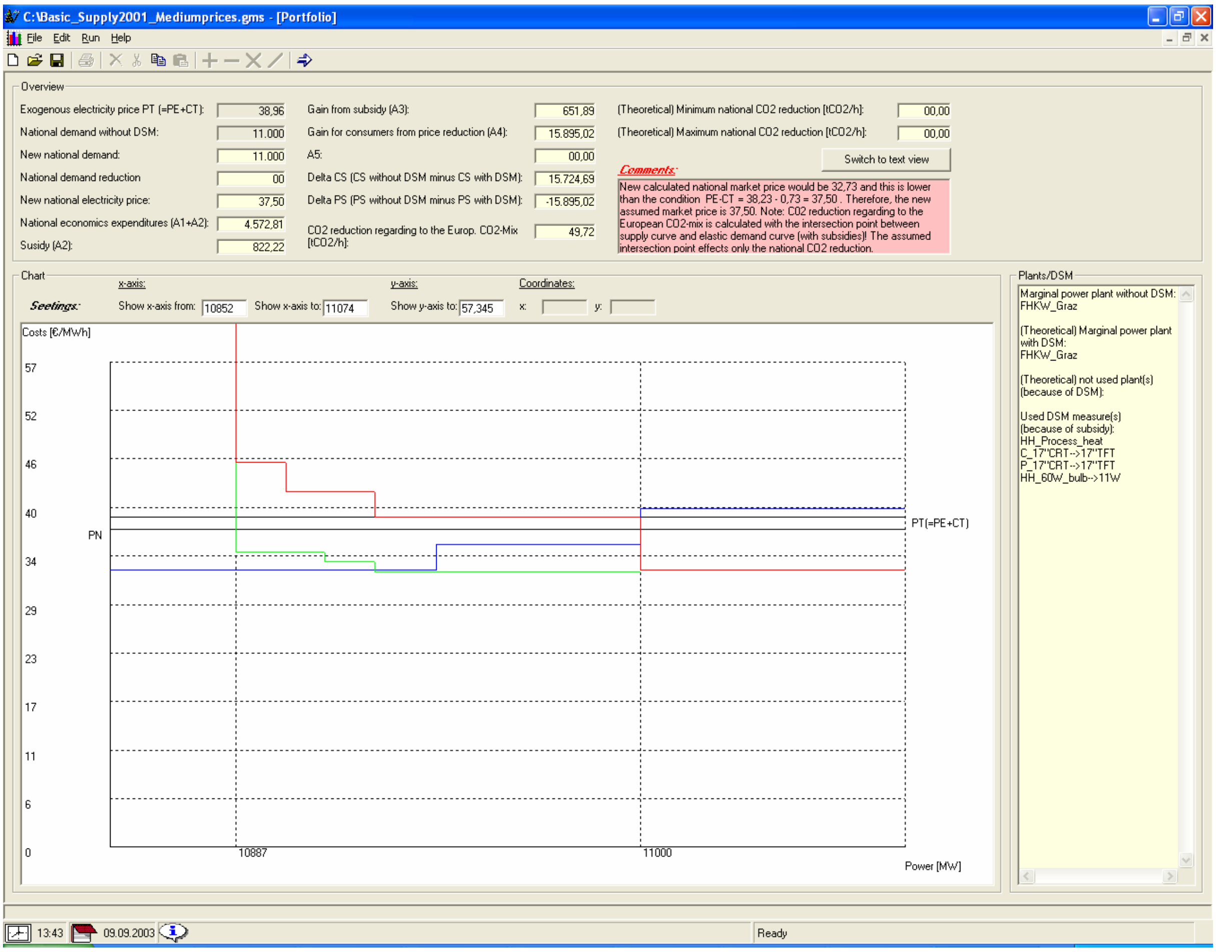

Figure 8.4: Graphical results[127] for model 2, medium price scenario based on supply curve for the year 2001

8.3.3 Model 2 with C_T>0 based on supply curve for the year 2010

For the scenario performed in this chapter all input parameters are the same as in chapter 8.3.1. The scenario is based on the expected supply curve for the year 2010 (see also chapter 5.3). This means that the higher market price of 38.23€/MWh is a result of high fuel prices and not a result of lack in supply.

The simulation results in a national load reduction of 113MW and market price (wholesale price plus transmission) reduction of about 2.1%. The achieved price reduction is lower than the transmission costs and therefore the national load reduction of 113MW leads to a national supply and CO_2 reduction. The necessary taxes for the support of DS-measures does not change compared to chapter 8.3.2, because of same DS-measures achieved. As a result of the changed marginal power plant compared to chapter 8.3.2 the national CO_2 reduction changes.

[127] German comma settings

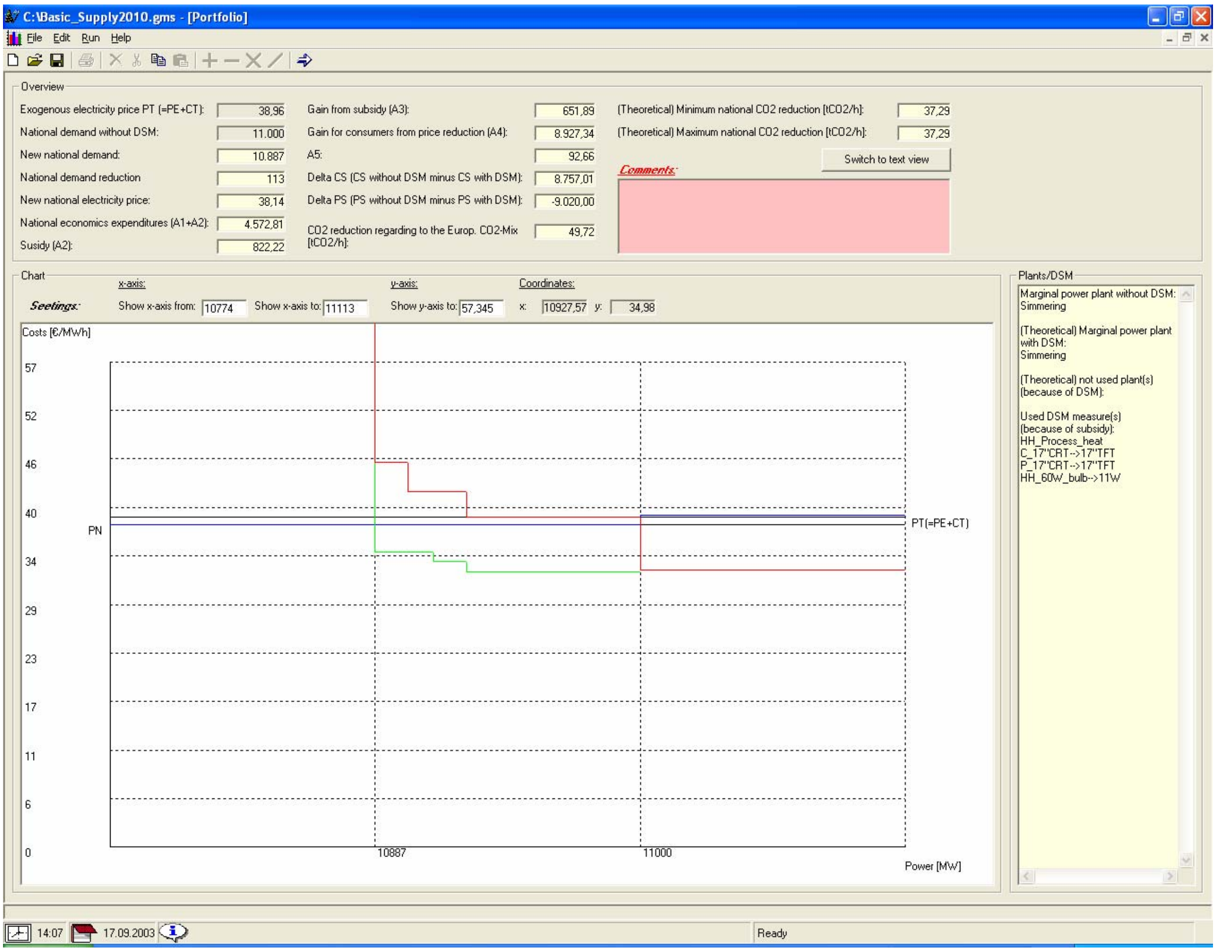

Figure 8.5: Graphical results[128] for model 2, medium price scenario based on expected supply curve for the year 2010

8.4 High price scenario

The assumed market price of 48€/MWh results in fully achieved high efficient appliances. No subsidies have to be paid to encourage the customers to invest in DS-measures and therefore no additional fee is necessary.

Comparing this result with the current “low” price of 28.48€/MWh this means that all achieved measures reduce the estimated on-peak demand of 11GW from chapter 5.1[129] by about 247MW <u>without any money from the society</u>.

The possibility to react to price signals reduces the estimated on-peak spot market price of 48€/MWh by about 6.3% according to the estimated supply curve for the year 2010 in case the transmission and transaction costs between Austria and the rest of Europe are higher than 3€/MWh.

[128] German comma settings

[129] It must be remembered that the forecast performed in chapter 5.1 does not consider any DSM-programs. Hence, the results obtained from this forecast lead to demand values without energy savings and load management programs.

9 Conclusions

The development of the demand curve is of core relevance for the achievement of a functioning competitive electricity market, its corresponding market performance and market price. Furthermore, to implement a market which contributes to the Kyoto target a consideration of the demand curve and its corresponding energy efficiency is absolutely necessary.

This work provides evidence that there is still a tremendous potential for demand reduction and efficiency increase as well as information in Austria to explore:

- Short term versus long term demand curve
- Information campaigns to explain the importance of "smart" electricity usage and
- Information campaigns to eliminate prejudices and misunderstandings of some technical equipment and
- Customers have to be educated to respond to price signals in the short term as well as in the long run

In this work, effects of a very simple long term demand curve used by 20% of all household, commercial and public customers are considered. Only very easy to change appliances as light bulbs, freezers, refrigerators, dish washers, washing machines, driers, electrical cooking devices and computer monitors and their reduction potentials are combined to the long term demand curve. No consideration of very inefficient electrical heating systems took place. As investigations in this work have shown a huge reduction potential for electrical heating systems, especially for the residential sector, exist.
However, because of the used approach that an inefficient device gets only replaced by an efficient device when the investment costs and operation costs of the new appliance are lower than for the inefficient device social behavior and personal preferences of customers are neglected. For electrical heating systems also the architectural structure and personal preferences are important. Therefore a determination of a replacement rate for electrical heating system is very difficult. Furthermore, no demand shifting/reduction because of the short term demand curve is investigated in detail for all customer sectors in Austria. Therefore, the real reduction potential because of the high variety of demand-side (DS)-measures and short term price reactions is higher than shown in this thesis. Due to this expected high efficiency increase potential public relations and customer education are very important. From this point of view the set up of an information system and customer care office responsible for efficiency and demand related questions is absolutely necessary to overcome technical and social barriers. Such a system and office must be run by customer representatives and not by utility representatives.

To emphasize the effects of technical misunderstandings the application tariff (= tariff at which the operation of the high efficient device is cheaper than for the inefficient device) for high efficient light bulbs is presented: The "rational" application tariff for high efficient light bulbs found in this work is 0.8€c/kWh. This value is far lower then the actual electricity tariffs charged by utilities. However, most of customers do not have the information about the ten times higher lifetime of high efficient light bulbs compared to ordinary light bulbs. Therefore, customers recognize approximately a 20 times higher application tariff. This "technical" misunderstanding is a major barrier for the implementation of high efficient light bulbs. To overcome these barriers education and information campaigns are very important tasks on the way to a functioning competitive market which contributes to a sustain electricity system.

As shown in this work high market prices support the application of new DS-measures. In contrast at low prices incentives are necessary that customers will invest in DS-measures and high efficient devices. Therefore, a pool system is suggested in which each customer pays money in form of a very small additional fee (comparable to the CHP charge or stranded investment charge on electricity bills in Austria). The collected money must be dedicated to customers who are interested in DSM. However, a basic conclusion of this work which can also be found in other basic textbooks is the negative change in consumer and producer surplus because of subsidies, without any consideration of external costs. The intersection point between supply and original elastic demand curve is always the optimum in the behavior of producers and consumers, where the producer surplus and the consumer surplus become a maximum. „Artificial" deviation from this optimal point because of subsidies results in a disadvantage of at least one group. Because of the subsidies the intersection point is shifted from the optimal intersection point to a non optimal point. As a result of this shift the sum of the change in producer and consumer surplus is always negative ($\Delta PS+\Delta CS<0$). Of course, this is a very basic conclusion but it is a reminder that DS-measures are not for free as many people believe.

Investigations performed in this work show that additional investments in few and very simple DS-measures of €142m reduce the forecasted peak load of 11GW for 2010 by about 2.2% and leads to a reduction in electricity price of about 6.3%. However, this price reduction can only be achieved when transmission barriers between Austria and Europe exist. Without any natural barriers (e.g. transmission congestion or transaction costs) or artificial barriers no price reduction in Austria can be obtained. Because of missing transmission costs all in Austria reduced demand is directly exported to Europe and the Austrian wholesale price is adjusting to the volatile European market prices. Therefore, barriers between Austria and the rest of Europe are necessary do support national DSM -programs and reduce price spikes. From a national point of view when transmission capacities become more and more restricted in near future (it is very expensive to invest in new grid capacities – environmental restrictions,...) national DSM will become more and more effective.

As a result of these investigations the two principle measures – DSM and production of electricity with a new additional thermal power plant – should be treated equal from an economic point of view. Therefore, an independent regulator has two options to manage price spikes because of a possible looming imbalance between supply and demand:

- Enforce the construction of new (thermal) power plants and increase the CO_2 emissions or
- Enforce DSM-programs and hence, reduce CO_2 emissions

All investigations performed in this work show impressively the possibility of the customers to decrease the whole electricity system price, increase the energy efficiency and reduce CO_2 emissions. Because of all these found advantages the total electricity market performance increases a lot. The "old" opinion that only additional power plants can manage the problem of imbalances between supply and demand is outdated. Nevertheless, energy saving and load management only won't be solve the problem, but it is important that the electricity industry recognizes that there is also a second side – the customer.

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A Appendix

A.1 Determination of the Rebound Effect

$$Service\ s = \eta \times e \qquad \textbf{(A.1)}$$

η *Efficiency of the energy (electricity) usage*
e *Energy (Electricity) [kWh]*

It is assumed that a service consists of the following elements:

$$s = f(k, e, t, q; c) \qquad \textbf{(A.2)}$$

with
k *Capital*
e *Energy*
t *Time*
q *Quality: Higher quality decreases the service level or forces the increase of the input to remain a stable service level.*
c *Congestion*

The service <u>increases</u> with:

- higher income (more capital)
- higher energy input
- more time and

The service <u>decreases</u> with:

- higher congestions
- higher quality

Therefore, following derivations are given:

$$\frac{\partial f}{\partial k} > 0; \frac{\partial f}{\partial e} > 0; \frac{\partial f}{\partial t} > 0; \frac{\partial f}{\partial c} < 0; \frac{\partial f}{\partial q} < 0 \qquad \textbf{(A.3)}$$

The function s = f(k,e,t,q;c) is assumed to be concave, i.e.:

$$f_{kk} < 0; f_{ee} < 0; f_{tt} < 0 \qquad \textbf{(A.4)}$$

The benefit u(s,q) of the service (s) consumption with quality q is also a concave function. This fact is easily to understand: E.g. the increase in benefit of an increase in room temperature from 12°C to 22°C is higher than the increase in benefit of a temperature increase of 10°C from 22°C to 32°C.

Each consumer tries to maximize his or her personal gain over the benefit u(s,q), the benefit of the usage of other commodities v(x) and the opportunity costs φ(t). However, the expenditures for the service s and other commodities are restricted by the income (M).

$$\max.\ u(s,q) + v(x) - \varphi(t)\ \ over\ \ k, e, q, x, t \qquad \textbf{(A.5)}$$

with

$$s = f(k,e,t,q;c); \delta k + pe + \kappa q + x \leq M \qquad \textbf{(A.6)}$$

with

$$x \geq 0; k \geq 0; e \geq 0; q \geq 0 \ and\ t \geq 0 \qquad \textbf{(A.7)}$$

M *Income (Money)*
v(x) *Benefit of the expenditures in all other commodities x. v(x) is concave.*
φ(t) *The output of the service s is linked to unpleasant activities. (=opportunity costs) φ is convex.*
δ,p,κ *Price for one unit of the investigated input factor.*

Regarding to (A.1) efficiency is the ratio between the service output and energy input. Neglecting the quality (q) and transaction costs (φ) the following equation for u is determined.

$$u = u(s) = u(e\eta) \qquad \textbf{(A.8)}$$

This results in the simplification of

$$\max.\ u(s) + v(x)\ over\ \eta, e, x \qquad \textbf{(A.9)}$$

$$\delta K(\eta) + pe + x \leq M \qquad \textbf{(A.10)}$$

with

$$x \geq 0; \eta \geq 0, e \geq 0 \qquad \textbf{(A.11)}$$

Assuming Inada Conditions[130] the unequal sign can be replaced by the equal sign. Due to this assumption the problem can be easily solved.

$$u(s) + v(x) \Rightarrow u(s) + v(M - pe - \delta K) \qquad \textbf{(A.12)}$$

Assuming minor changes of the non linear function v(x) depending of e and η, v(x) can be replaced by the Taylor approximation[131] of v(x). The last step is to standardize the function with $v'(x_0)$.
The result of all these operations is:

$$\max. u(s) - pe - \delta K(\eta)\ over\ e, \eta \qquad \textbf{(A.13)}$$

Differentiation of (A.13) to the energy (e) leads to the "optimum condition first order".

„Optimum condition first order":

$$\frac{\partial}{\partial e} = u'\eta - p = 0 \Rightarrow u' = \frac{p}{\eta} \qquad \textbf{(A.14)}$$

[130] $\lim u' \Rightarrow \infty\ and\ \lim v' \Rightarrow \infty\ for\ s \Rightarrow 0\ and\ x \Rightarrow 0$
[131] Note: constant parts are not relevant in Taylor approximations.

A.2 Data of thermal power plants

Source: Brennstoffstatistik 1995			1995	Used primary energy 1995												Specific CO_2 emissions
Power plant	Utility	Bottleneck power	Net electricity production	Hard coal		Brown coal		Oil		Gas		Others		Total		Electricity plus heat production
				Electricity	Heat	Electricity	Heat	Electricity	Heat	Electricity	Heat	Electricity	Heat	Electricity	Heat	
			MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	kg-CO2/kWh
Donaustadt	Wienstrom	324	515,830	0	0	0	0	14,875	0	1,413,636	0	0	0	1,428,511	0	0.562
Leopoldau	Wienstrom	156	573,464	0	0	0	0	48	0	1,200,225	344,765	0	0	1,200,273	344,765	0.247
Simmering	Wienstrom	999	2,624,567	0	0	0	0	1,140,601	0	5,344,856	405,764	0	0	6,485,456	405,764	0.330
Dürnrohr	EVN	352	1,480,370	2,380,642	0	0	0	0	0	1,121,866	0	0	0	3,502,508	0	0.701
Korneuburg	EVN	127	306,455	0	0	0	0	0	0	699,494	0	0	0	699,494	0	0.461
Theis DT	EVN	412	378,042	0	0	0	0	10,076	0	1,006,641	0	0	0	1,016,717	0	0.545
Theis GT	EVN	140	1,618	0	0	0	0	0	0	5,972	0	0	0	5,972	0	0.745
FHKW Mödling	EVN	3	9,384	0	0	0	0	0	0	16,388	99,669	0	0	16,388	99,669	0.250
Riedersbach I	OKA	55	83,385	202,082	0	0	0	65,106	0	0	0	0	0	267,187	0	1.043
Riedersbach II	OKA	165	522,987	1,179,132	9,224	197,899	1,471	22,310	4,258	0	0	0	0	1,399,341	14,953	0.893
Timelkam II	OKA	60	250,656	179,202	5,915	685,294	20,902	53,558	1,590	5,448	410	0	0	923,502	28,818	1.053
Timelkamm GT	OKA	106	2,371	0	0	0	0	0	0	0	0	7,994	0	7,994	0	0.979
FHKW Graz	STEWEAG	57	55,370	0	0	0	0	0	0	170,706	137,810	3,345	4,587	174,051	142,397	0.246
MHKW Knittelfeld	STEWEAG	2	6,706	0	0	0	0	0	0	15,673	29,392	0	0	15,673	29,392	0.236
FHKW Mellach	STEWEAG	246	890,886	2,109,999	184,134	0	0	0	0	187,130	13,797	0	0	2,297,130	197,930	0.572
Neudorf / Werndorf	STEWEAG	110	387,827	0	0	0	0	0	0	1,034,090	40,140	2,831	143	1,036,921	40,284	0.479
Pernegg	STEWEAG	100	5,086	0	0	0	0	16,487	0	0	0	0	0	16,487	0	0.903
MHKW Rottenmann	STEWEAG	3	4,388	0	0	0	0	8,360	15,954	0	0	178	59	8,538	16,013	0.352
Dürnrohr	VK	405	712,410	1,189,354	0	0	0	0	0	528,028	0	0	0	1,717,381	0	0.718
Korneu II	VK	285	91,271	0	0	0	0	0	0	228,846	0	0	0	228,846	0	0.506
St. Andrä 2	DK	116	79,712	229,228	1,793	0	0	11,204	217	0	0	1,761	18,536	242,192	20,546	0.841
Voitsberg 3	DK	330	1,068,538	0	0	2,952,175	13,406	10,030	0	0	0	0	0	2,962,205	13,406	0.962
Zeltweg	DK	137	123,104	333,279	0	18,618	0	1,527	0	0	0	0	0	353,423	0	0.981
FHKW Kirchdorf	FHKW Kirchdorf	12	9,893	0	0	0	0	449	2,778	15,926	57,090	0	0	16,375	59,867	0.259

FHKW Klagenfurt	STW. Klagenfurt	28	118,804	4,199	4,863	0	0	219,709	320,532	56,258	65,195	0	0	280,167	390,590	0.379
FHKW Linz Mitte	ESG Linz	70	190,487	0	0	0	0	462,251	241,844	165,480	99,600	249	0	627,980	341,444	0.479
FHKW Linz Süd	ESG Linz	116	631,618	0	0	0	0	0	0	1,255,070	189,170	2,870	557	1,257,940	189,727	0.325
HKW Salzburg Mitte	STW. Salzburg	18	73,212	0	0	0	0	162,712	149,753	57,850	52,310	0	0	220,562	202,063	0.445
HKW Salzburg West	STW. Salzburg	3	9,033	0	0	0	0	193	1,282	11,930	83,400	0	0	12,123	84,682	0.241
HKW Salzburg Nord	STW. Salzburg	14	42,817	0	0	0	0	54,893	213,229	0	0	0	0	54,893	213,229	0.314
FHKW St. Pölten Nord	STW. ST. Pölten	14	32,091	0	0	0	0	7,646	36,244	37,078	211,033	0	0	44,724	247,277	0.264
FHKW St. Pölten Süd	STW. ST. Pölten	5	10,930	0	0	0	0	2,607	11,926	13,839	76,187	0	0	16,445	88,113	0.278
FHKW Wels	EW Wels	15	58,246	0	0	0	0	0	0	153,583	188,885	0	0	153,583	188,885	0.304

Table A.1: Basic data for thermal power plants for the year 1995. Source: Brennstoffstatistik

A.3 Source code of "NESoDSM"

It is important to emphasize that only selected samples of the entire algorithm are shown. The entire source code of the model consists of more than 5,000 rows and more than 195,000 characters. Therefore, it would not be useful to show the entire algorithm.

- Calculation of fictitious demand L_2 for model 1 ($C_T = 0$)

```
Function DemandDSM(Price_Market As Double) As Long
   Dim i As Integer

   DemandDSM = -1  'no result
   For i = 1 To DemandIndex
      If CDbl(Demand(2, i)) > CDbl(Demand(1, i)) Then
         If CDbl(Demand(1, i)) < Price_Market And Price_Market < CDbl(Demand(2, i)) Then
            DemandDSM = i
         End If
      End If
   Next i
End Function
```

- Calculation of national economics expenditures (A_1+A_2) for both models

```
Function FA1A2(ByVal L1 As Long, ByVal l2 As Long) As Double
   Dim i As Long

   FA1A2 = 0
   For i = l2 To L1 - 1
      FA1A2 = FA1A2 + CDbl(Demand(1, i)) + CDbl(Demand(5, i))
   Next i
End Function
```

- Calculation of subsidies (A_2) for both models

```
Function Fa2(DemandwithDSM As Long) As Double
   Dim i As Long

   Fa2 = 0
   For i = DemandwithDSM To CLng(ValueScalars(1)) - 1
      Fa2 = Fa2 + CDbl(Demand(5, i))
   Next i
End Function
```

- Calculation of new L_2 for model 2 – case 2a

```
Function FL2Model2() As Long
   Dim i As Integer
   Dim Upper_Index As Long

   FL2Model2 = -1

   If SupplyIndexNewModel2 > DemandIndex Then
      Upper_Index = DemandIndex
   ElseIf SupplyIndexNewModel2 < DemandIndex Then
       Upper_Index = SupplyIndexNewModel2
   End If
   For i = 1 To Upper_Index
      If CDbl(SupplyCurveNEwModel2(1, i)) = CDbl(SupplyCurveNEwModel2(2, i)) And CDbl(Demand(2, i)) >
CDbl(SupplyCurveNEwModel2(1, i)) And CDbl(Demand(1, i)) < CDbl(SupplyCurveNEwModel2(1, i)) Then
         FL2Model2 = i
         i = Upper_Index
      End If
   Next i
End Function
```

- Calculation of new demand $L_{2'}$ for model 2 – case 2b

```
Function NewDemandModel2a(AssumedPrice As Double) As Long
   Dim i As Long
```

```
   NewDemandModel2a = -1
   For i = 1 To SupplyIndexNewModel2
      If (CDbl(SupplyCurveNEwModel2(1, i)) < CDbl(SupplyCurveNEwModel2(2, i))) _
      And AssumedPrice > CDbl(SupplyCurveNEwModel2(1, i)) And AssumedPrice < CDbl(SupplyCurveNEwModel2(2, i)) Then
         NewDemandModel2a = i
         i = SupplyIndexNewModel2
      End If
   Next i
End Function
```

- <u>Calculation of new L_2 after a new national market prices was assumed, model 2 – case 2b</u>

The assumption of a new market price does also affect L_2.

```
Function DemandModel2a_L2(p As Double) As Long
   Dim i As Long

   DemandModel2a_L2 = -1
   For i = 1 To DemandIndex
      If CDbl(Demand(1, i)) < p And CDbl(Demand(2, i)) > p Then
         DemandModel2a_L2 = i
         i = DemandIndex
      End If
   Next i
End Function
```

- <u>Calculation of A_5 for model 2</u>

```
Function fa5(l2 As Long, L1 As Long) As Double
   Dim i As Integer
   Dim PreviousValue As Double

   fa5 = 0
   For i = l2 To (L1 - 1)
      'Jumps!!!
      fa5 = fa5 + ((CDbl(ValueScalars(2)) + CDbl(ValueScalars(3))) - CDbl(SupplyCurveNEwModel2(1, i)))
      PreviousValue = ((CDbl(ValueScalars(2)) + CDbl(ValueScalars(3))) - CDbl(SupplyCurveNEwModel2(1, i - 1)))
      If PreviousValue <> ((CDbl(ValueScalars(2)) + CDbl(ValueScalars(3))) - CDbl(SupplyCurveNEwModel2(1, i))) Then
         fa5 = fa5 + ((CDbl(ValueScalars(2)) + CDbl(ValueScalars(3))) - CDbl(SupplyCurveNEwModel2(1, i))) - PreviousValue
      End If
   Next i
End Function
```

- <u>Calculation of CO_2 reduction for model 1</u>

```
Sub PlantsDSMMeasuresModel1(FictNewDemandwDSM As Long, OldDemand As Long, OffsetSCurve As Long)
   Dim i As Integer
   Dim j As Integer
   Dim TexttxtBox As String
   Dim RealLoadReduction As Long
   Dim TypeArray(100) As String
   Dim Counter As Integer

   frmPortfolio.txtPlantsDSM.Text = ""
   TexttxtBox = ""
   'Marginal Plant before DSM
   TexttxtBox = "Marginal power plant:" & LineFeed
   'Very important: OldDemand - 1! Reason: Generating of origin intersection point
   'To make sure that the right marginal plant is used: OldDemand - 1
   'Don't forget OffsetSCurve
   TexttxtBox = TexttxtBox & SupplyCurve(4, OldDemand - 1 + OffsetSCurve) & LineFeed & LineFeed
   'DSM measures
   Counter = 1
   TexttxtBox = TexttxtBox & "Used DSM measures" & LineFeed & "(because of subsidy):" & LineFeed
   'Use demand curve with subsidies!
   'jump point!!
   TexttxtBox = TexttxtBox & Demand(4, FictNewDemandwDSM + 1) & LineFeed
   TypeArray(Counter) = Demand(4, FictNewDemandwDSM + 1)
   'Note: olddemand-1!!!
   'Reason: Greating of intersection point: Jump point demand curve
   'and jump point supplycurve and exogenous price creates intersection point!
```

```
    For i = FictNewDemandwDSM + 1 To OldDemand - 1
        If CDbl(Demand(2, i)) > CDbl(Demand(2, i + 1)) Then
            Counter = Counter + 1
            TexttxtBox = TexttxtBox & Demand(4, i + 1) & LineFeed
            TypeArray(Counter) = Demand(4, i + 1)
        End If
    Next i
    RealLoadReduction = OldDemand - FictNewDemandwDSM
    'Find types and regarding power reduction
    'Case sensitive!
    'For example DSMM100<>DSMMP100
    For i = 1 To Counter
        For j = 1 To 100
            If TypeArray(i) = SheetsData(2, 6, j) Then
                If SheetsData(2, 5, j) = "S" Or SheetsData(2, 5, j) = "s" Then
                    RealLoadReduction = RealLoadReduction - SheetsData(2, 2, j)
                End If
                j = 100
            End If
        Next j
    Next i
    frmPortfolio.txtPlantsDSM.Text = TexttxtBox
    frmPortfolio.lblCO2ReductionMIX.Caption = Format(RealLoadReduction * CDbl(ValueScalars(4)), "#0,0.00")
End Sub
```

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