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Abstract (max. 2000 char.):

Due to characteristics of the power system, costs of producing electricity vary considerably over short time intervals. Yet, many consumers do not experience corresponding variations in the price they pay for consuming electricity. The topic of this report is: are consumers willing and able to respond to short-term variations in electricity prices, and if so, what is the social benefit of consumers doing so?

Taking Denmark and the Nord Pool market as a case, the report focuses on what is known as short-term consumer flexibility or demand response in the electricity market.

With focus on market efficiency, efficient allocation of resources and security of supply, the report describes demand response from a microeconomic perspective and provides empirical observations and case studies. The report aims at evaluating benefits from demand response. However, only elements contributing to an overall value are presented. In addition, the analyses are limited to benefits for society, and costs of obtaining demand response are not considered.

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Preface

This report summarises the analyses and conclusions of the project ”Short-term flexibility in the electricity consumption – quantification, simulation and valuation”, supported by the Danish Energy Research Programme. The project has been carried out by the project group:

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1 Abstract and summary

Taking Denmark and the Nord Pool market as a case, this report focuses on what is known as short-term consumer flexibility or demand response in the electricity market.

Central topics in relation to demand response are the notification, duration and frequency of the required demand response: when does the consumer know he is requested or motivated to change his consumption, for how long, and how often he should to change the electricity consumption? This report focuses on two problems in the electricity market:

- Market efficiency and efficient allocation of resources
- Security of supply.

The report describes demand response from a microeconomic perspective and provides empirical observations and case studies. The report aims at evaluating benefits from demand response. Applying different methods for evaluating benefits from demand response, a range of elements contributing to the overall value are presented. The values of these elements are, however, not directly additive. Also, the focus is on benefits for society, although costs of increasing demand response are not considered.

Looking at market efficiency, two analyses of varying contra fixed consumer prices and market power mitigation, respectively, are included (sections 4.3 and 5.2).

Exposing users to the electricity prices at the Nord Pool day-ahead market, as opposed to fixed rates over the year, implies a welfare gain if consumers are able and willing to react to prices. Depending on the size of price variations and the flexibility of electricity consumption, considerable variations in the welfare gain are found. However, for observed Nord Pool price variations from 2001 to 2004 and reasonable price elasticities, welfare gains are found to be moderate. Increasing consumer flexibility, introducing enabling technologies and/or assuming larger future price variations in the market will increase the welfare gain.

Assuming very few suppliers in the electricity market (two equally sized firms), the welfare gain from market power mitigation is potentially larger. However, with additional suppliers, increasing consumer flexibility may imply a welfare loss. The analysis shows that no clear conclusion is possible concerning welfare effects from market power mitigation through increased demand response.

However, a common conclusion from the two market efficiency analyses is that increasing consumer flexibility implies lower electricity prices and price variations, reducing users’ risk and hedging costs and in turn providing more correct price signals for, e.g. investments, but this is not evaluated in the analyses.

Security of supply problems are treated in the sections 4.4 and 5.1. Evaluating the value of security of supply is difficult as there are only few critical situations with a potentially

large value. Both the frequency of critical situations and the value of avoiding disconnection of users are difficult to assess. In addition, in many cases only a limited demand response is required to solve a critical situation.

Using Monte Carlo simulations (with a detailed representation of the frequency of critical situations) and a partial equilibrium model of the Nordic power system, alternative scenarios including demand response options are analysed in section 5.1. A major conclusion from the analysis is that production costs in the alternative scenarios are almost identical, but a large gain is obtained by reducing disconnections of users. This gain critically depends on the value of disconnections, which in the analysis is set at NOK 5,000/MWh. A gain not included in this analysis is the value of saved investments in peak capacity.

One way to assess the value of disconnections is to evaluate the compensation rates required for users to accept a disconnection. The analysis in section 4.4 shows the potential for voluntary disconnections of dishwashers, washing machines and dryers at residential users. The average compensation level required is relatively high but some users are willing to be disconnected in return for moderate compensations. Targeting other household appliances and introducing enabling technologies, the required compensation rates may be substantially lower.

After an introduction defining short-term demand response and an introduction to microeconomic theory concerning demand response issues in chapter 3, chapter 4 describes markets and empirical observations. Chapter 5 presents quantitative analyses of the value of demand response, and finally conclusions are given in chapter 6.

2 Introduction

Twenty years ago, the dominant production technology for electricity in Denmark was large coal-fired power plants, and production and trade of electricity was organised in regulated monopolies. Today, important parts of the electricity system have been liberalised and production technologies have changed, including significant contributions from wind turbines and decentralised natural gas-fired combined heat and power plants. However, changes do not stop here. Communication and computing technology as well as new production technologies (e.g. micro-generation) may totally change the future electricity system.

In SmartGrid (EU, 2006) it is pointed out that the most distinguishing feature of the future electricity system will be the ability for the users to play an active role in the supply chain.

The active role of the demand side is the issue of this report. “Demand response” is the key word describing that users of electricity in a voluntarily way react to prices or other signals. Some types of electricity use can easily be controlled, for instance large scale-industrial demand or small-scale electric heating in households. In this way controlled electricity demand can act as electricity storage and/or as a peak production (gas turbine style) unit. Such characteristics are beneficial in the electricity system.

2.1 Defining demand response and why is it important

Four fundamental characteristics of the power system are:

- In real time, electricity supply must always equal demand.
- Electricity is not economically storable at the scale of large power systems.
- Usage varies over time due to consumer behaviour and the production structure of the economy.
- Costs of producing electricity vary considerably with the unit generating the electricity.

The implication of these characteristics is that the cost of producing electricity varies considerably over short time intervals and that a societal benefit may be gained by consumers seeing and reacting to the varying prices of electricity. For various reasons, today most consumers are exposed to fixed annual rates and do not see short-term changes in retail prices. Therefore they have no incentive to respond to short-term conditions in the electricity market.

In general terms demand response (DR) may be defined as:
“Changes in electricity usage by end-use consumers from their normal consumption pattern in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.” (U.S. Department of Energy, 2006).

This definition focuses on wholesale market prices and power crises. For end users, the retail price, including the cost of transport of electricity and ancillary services, is important.

Related to the Nordic power market Nordel (2006) offers a more elaborated definition: *“Demand response (DR) is a voluntary temporary adjustment of electricity demand as a response to a price signal or a reliability-based action.*

- *DR may be short-term (capacity) or medium-term (energy).*
- *The price signal may come from the power market, intraday market, regulating power market after a TSO*[1] *call, balancing markets, ancillary services markets or from tariffs.*
- *Reliability-based actions may come from TSOs or distribution companies and can be activated manually or automatically.*
- *Distributed generation in consumption areas can be considered as DR.”*

The demand response may be expressed as:

- Peak clipping, where demand is decreased at critical hours, typically a few hours per year where prices/costs are high due to contingencies such as generator outages, failures on transmission lines or excessive demand conditions.
- Load shifting, where consumers shifts demand from high priced - to lower priced periods, typically on a daily basis from an afternoon peak to later in the evening.
- Valley filling, where demand is increased at hours where the price is low, e.g. in the Nordic system at night-hours with a large production by wind turbines.

And the change in consumer behaviour may be obtained by:

- Price-based instruments exposing consumers to the time-varying costs of electricity production, transport of electricity and ancillary services.
- Incentive programmes (reliability-based actions) providing incentives to reduce demand at critical hours. Typically demand side agreements with the TSO where consumers receive a reservation payment for allowing disconnections.

Increasing demand response focuses on two types of problems in the market: inefficiencies and security issues.

Most of the electricity consumers are exposed to fixed average rates and do not see the short-term time-varying costs of electricity production. Consequently, consumers tend to over-consume in hours with high costs and to under-consume in hours with low prices compared to a system with time-varying prices. This represents an inefficient resource allocation and the costs of electricity become higher than what is optimal as high-cost generators run too many hours etc. In the long term, reduced peak demand may reduce investments in peak power capacity running only a few hours per year. In addition, lack

[1] TSO is short for Transmission System Operator.

of demand response may give producers an opportunity to exercise market power, withholding capacity at contingencies and raise prices above the competitive level.

As electricity is not economically storable, in real time, supply and demand must be balanced at system level. An imbalance in the system can generate blackouts over a very large area within seconds. In this perspective, demand response aims at increasing the security of supply by giving consumers an incentive to react in critical situations. For governments and transmission system operators (TSOs), issues related to security of supply have been a major argument for supporting demand response activities. During contingencies demand response may act as a reserve capacity, offering load reductions to solve short-term constraints in the system, e.g. lack of generation or transmission capacity. As the notification may be very short for some of these contingencies, price-based programmes may be supplemented by incentive-based programmes.

2.2 Demand response options and markets (time scale)

To get a step further in understanding short-term demand response and options for improving demand response the time scales of the electricity system management, notification time, duration and frequency of requested response are important issues.

The time scales of system management range from several years to the last second for delivery of electricity as the construction of new capacity and transmission lines are large complex projects with a long planning horizon, and demand and supply must be in balance in real time.

Starting with the long-term investment, capacity and operation planning starts years to months before delivery of electricity, and action on the demand side includes changing consumer behaviour, electricity savings and substitution from electricity to district heating. Demand side actions can be motivated by energy prices, taxes or energy savings programmes. Demand side actions at this time scale is not included in (short-term) demand response, however, effects of short-term demand response may influence long-term capacity planning, e.g. reducing peak demand reduces the need for peak capacity, and this should be included in the benefits of demand response.

The day before actual delivery, the planning starts with scheduling which generators should operate in specific hours, based on expected demand. In a liberalised market this scheduling of production is determined in a day-ahead market, also determining day-ahead hourly prices for delivery of electricity. In the Nordic electricity market the Nord Pool day-ahead spot market is central. On 1 June 2006 for example, app. 30,000 MW (more than 50% of total demand) was traded in the spot market. The rest is traded bilaterally. However, in some cases the price for bilateral trade is related to the spot price. In the afternoon the day before delivery time, the TSOs receive a plan for the next day from all balance responsible. The TSOs check that the plans are consistent. When this is done, a plan exists for each hour of the next day, describing what will be produced and what will be consumed.

In Finland, Sweden and Eastern Denmark also an hour-ahead market exits: The Electricity Balance Adjustment Service, Elbas. This is also a commercial market, where electricity (production as well as demand) can be traded until one hour before delivery. The volume in this market is much smaller – in the order of 100 MW. Elbas can be used to trade corrections to the original plan. Wind power can be difficult to predict and conventional plants can fail.

The last hour before delivery, the TSOs take charge of the further planning and corrections. At delivery time regulating power is ordered to keep the balance in the system. Regulating power must be activated with a notice of 15 minutes. Usually, regulation power is only activated if the balance in the whole Nordic system shows an imbalance. If demand is larger than production, the frequency falls below the target value of 50 Hz. Regulating power is typically traded in blocs of 25 MW. The Nordic TSOs have a common list of possible providers of regulating power, sorted in merit order.

If major disturbances occur, reserves are activated. This includes automated and manual reserves. A disturbance can be a power plant or a transmission line that fails.

If different price-based instruments or incentive (reliability-based) programmes are implemented, demand response may be utilised in each of these markets.

2.3 Value-creating elements of demand response

Based on existing literature a long list of value-creating elements of demand response is constructed. Major elements focus on:

- Market efficiency
- System reliability
- Volatility of prices and quantities.

Market efficiency includes improved resource utilisation, market power mitigation and expression of consumer preferences. System reliability focuses on security of supply, and the stability of the system and grids. Volatility of prices and quantities concerns risk management, insurance values and hedging costs. Looking at who gains from demand response, Table 2.1 groups the value-creating elements according to agents benefiting most.

Actors/Timing	Short-term	Long-term
Consumer	Expression of preferences Lower prices Lower price volatility	Risk management Customer services Security of supply (price)
Producer/Investor	Lower volatility	Insurance values Lower hedging costs
TSO/DSO (Distribution System Operator)	System reliability Grid stability	Security of supply
Society	Market functionality Market power mitigation	Resource exploitation Option value Security of supply (level) Externalities

Table 2.1 Grouping of demand response elements.

In this report, not all of the elements of demand response will be evaluated, and in general focus is on the value for society. However, for practical implementation of consumer demand response, who gains and who pays for facilitating demand response is important. Quantitative evaluations of benefits from increased demand response are analysed in several sections: In section 4.3 benefits from market efficiency and consumers expressing preferences are evaluated, section 5.1 evaluates gains from improved security of supply calculating production costs and costs of disconnecting consumers in alternative supply scenarios, and section 5.2 evaluates gains from market power mitigation.

3 A microeconomic analysis of demand response

Economic theory says that in markets with perfect competition there is an efficient allocation of resources when the marginal utility of consumption equals the marginal costs of supply. In Figure 3.1 this is the point of intersection of the demand and supply curves giving an equilibrium electricity price of p* and a consumption of q* .

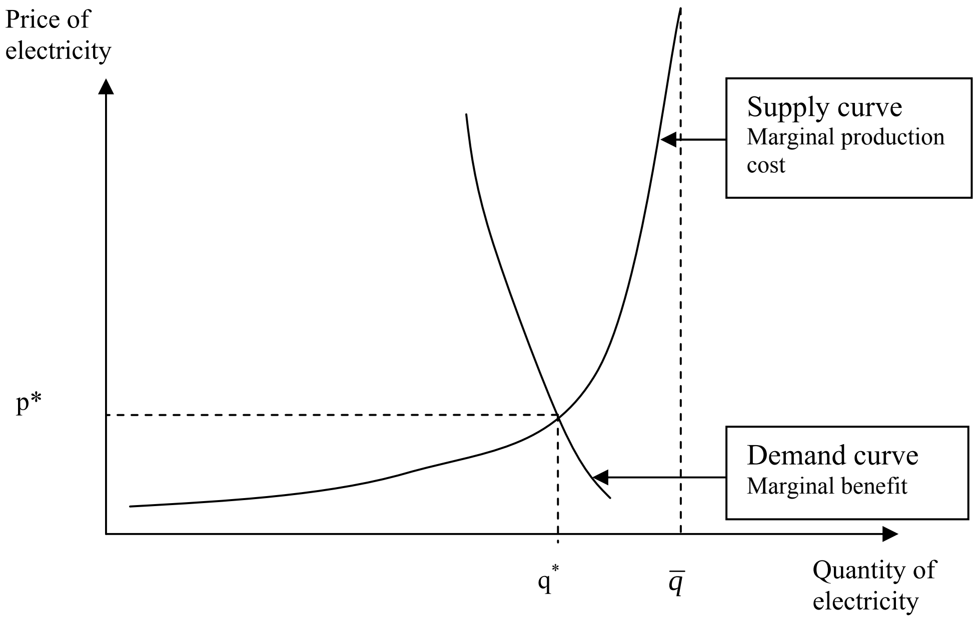


Figure 3.1 Equilibrium price and quantity in a perfect competitive market.

The supply curve is constructed by ranking generators from lowest to highest marginal operating costs. At the lower end, we have wind turbines, hydro-power, combined heat and power, coal-fired plants, and other base-load generators running most of the time at low operating costs. As production approaches capacity limits, we have peak-load units like condensing oil-fired power plants or natural gas turbines with fewer running hours and relatively high operating costs, i.e. the supply curve becomes very steep and ends at maximum production capacity $\bar{q}$. The demand curve is downward sloped as the marginal value of additional consumption is declining with additional consumption.

As such, Figure 3.1 has no time dimension and is applicable to any time scale. However, specifying characteristics of the demand and supply curves and the data of an analysis determines the time scale of the analysis. On an hourly scale, e.g. in the Nord Pool market, the demand curve changes according to the activities of businesses and residential consumer lifestyles and consumption patterns (shifting the position of the demand curve). This introduces a systematic variation in prices and quantities consumed. On working days, high demand (and prices) is observed in morning, afternoon and early evening hours and less in other hours. The effect of shifting demand curves is illustrated in Figure 3.2.

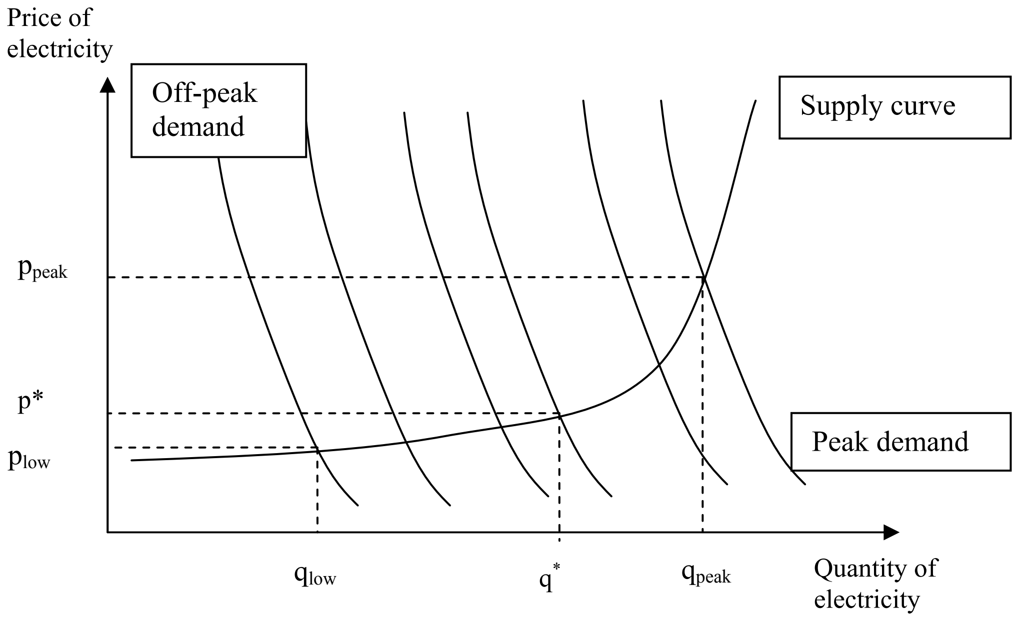


Figure 3.2 Changes in the demand of electricity.

In addition, due to changes in wind resources, outages etc., the supply curve shifts at times introducing further variations in the equilibrium price and quantity. However, this variation is not a systematic daily and weekly variation, and contrary to shifting demand curves shifting supply curves imply a negative correlation between the price and the quantity. This is mirrored in Figure 3.3, which shows only one peak demand curve,.

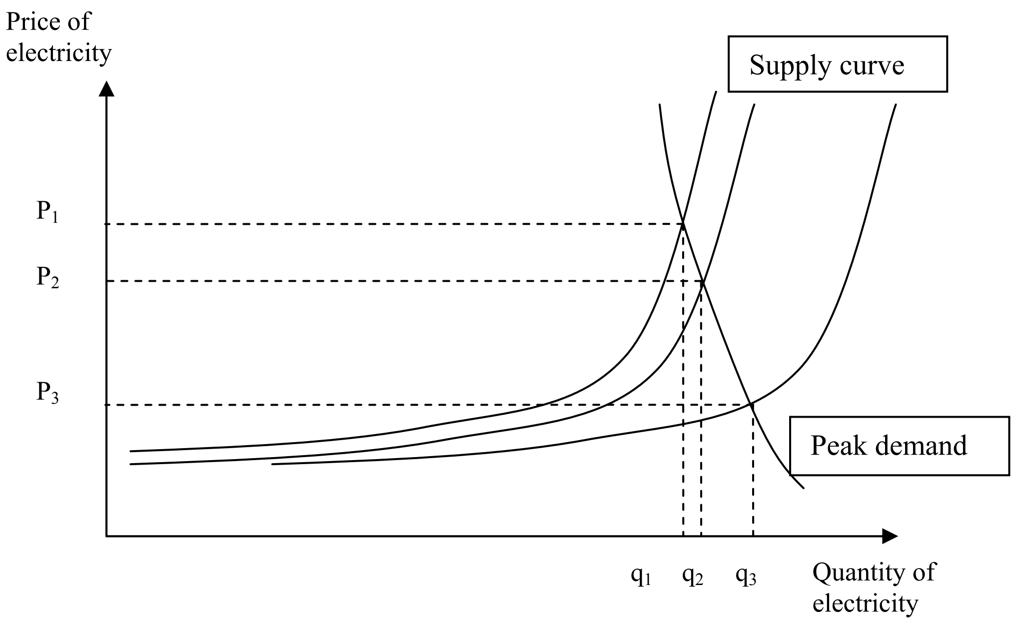


Figure 3.3 Changes in the supply of electricity.

Hourly equilibrium prices and quantities for the first two full weeks of 2005 for Eastern Denmark are shown in Figure 3.4, which combines demand and supply changes. This reveals a clear systematic daily and weekly variation, both in the quantity and the price of electricity, and due to shifts in demand there is a positive correlation between the price and the quantity variations. However, the figure also reveals a non-systematic variation in the price of electricity.

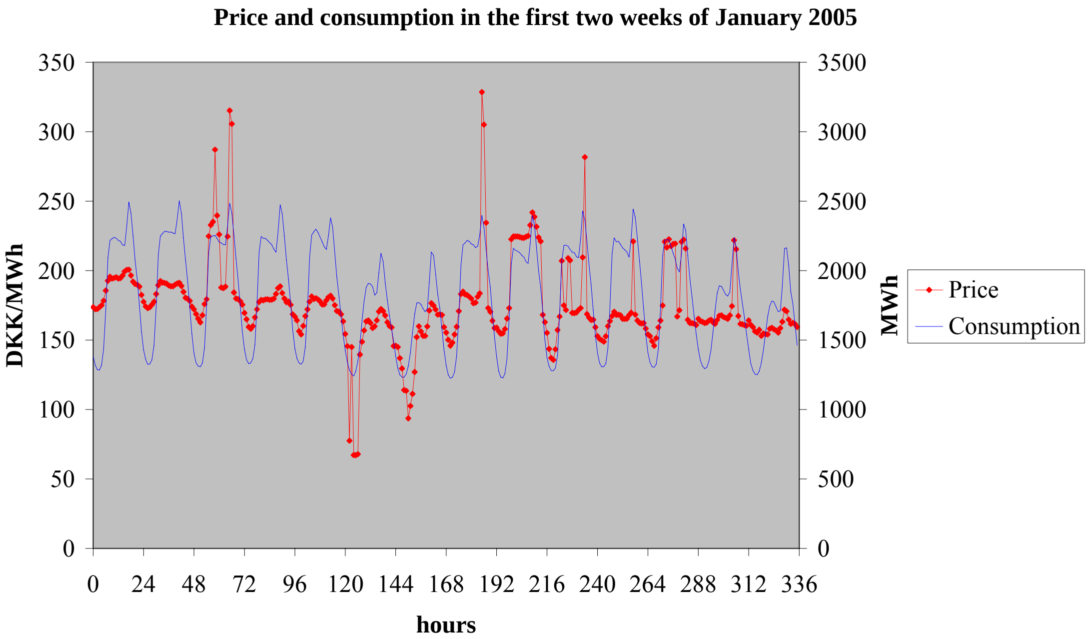


Figure 3.4. Hourly prices and consumption in Eastern Denmark in the first two full weeks of 2005.

In Denmark, most consumers are charged a price determined on the basis of a longer time period, e.g. three months or a year, and do not see the short-term price variations in the electricity market. For these consumers the expressed short-term demand curves in the market are vertical lines. If consumers have some flexibility in their electricity demand and are exposed to hourly price variations in the market, efficiency improves and there is a welfare gain. An illustration of the welfare gain is given in Figure 3.5, which shows one supply curve, and a peak and an off-peak demand curve. At average pricing (price P_{avg}) consumers demand electricity at point A (A') incurring marginal production costs at point B (B'). The efficient pricing, i.e. the point where the supply and demand curves intersect, is marked C (C'), and the welfare gain from introducing marginal cost pricing is the shaded triangles ABC and A'B'C'. In off-peak periods, electricity that has a value to consumers when priced according to its marginal supply costs is now consumed, and in peak periods an excess demand not valued the supply costs is foregone. This means that, if consumers react to prices, introducing marginal cost pricing implies a welfare gain, load shifting from high-price periods to low-price periods, and reduced volatility of prices (changes on the price axe from the cost points B and B' (not marked on the price axe) to the points of intersection C and C'). The size of these effects crucially depends on the short-term flexibility of consumers, represented by the slope of the demand curve. If consumer flexibility is large (a flat demand curve), quantity and price effects and the welfare benefit of consumer response to prices are large.

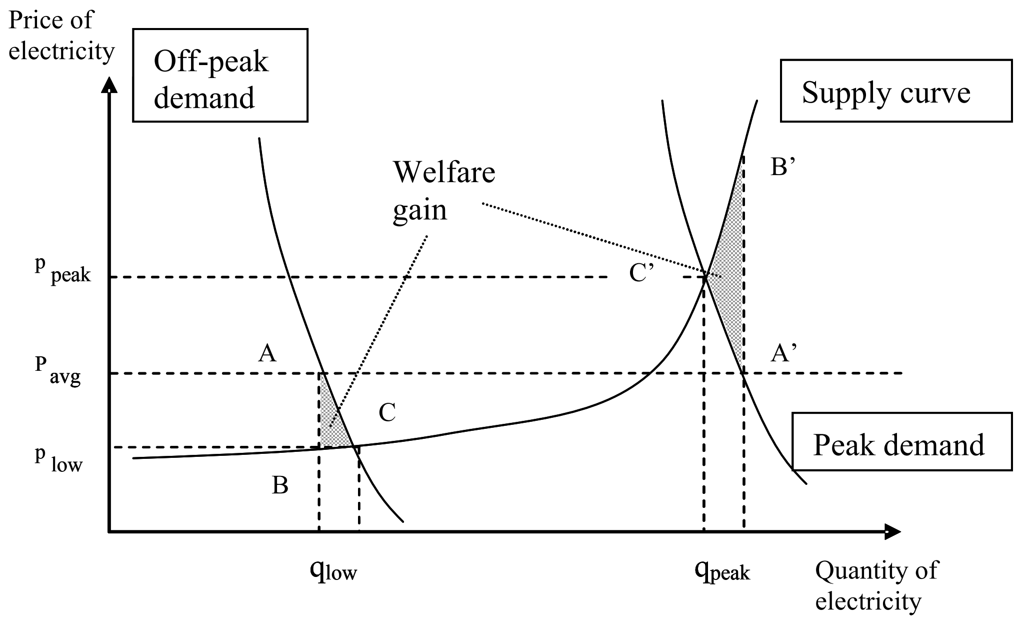


Figure 3.5   Effects of changing from average pricing to marginal cost pricing in the short-term electricity market.

Focusing at peak demand periods, a number of additional effects of demand response are:

- Situations where supply cannot meet demand, i.e. security of supply problems
- Reduced incentive for suppliers to exercise market power
- The value of reduced investments in peak power units

In extreme cases, if demand is inflexible, demand may exceed supply and no market clearing price is obtained. In Figure 3.6 this is illustrated by the vertical line D_1 at the load q_{peak}. Flexibility of demand may solve the problem changing the slope of the demand curve (curve D_3) and obtaining a market clearing price at P_{peak}.

If there is no market price in the spot market, all demand bids can be rationed with proportional rationing. If the buyers do not act, the problem is transferred to the balancing market, and if capacity is lacking in the balancing market, other reserves may be used or demand will be disconnected, i.e. the disconnection is made without considering individual consumer welfare.

"Given the wide range of customer circumstances and difficulties in predicting which customers will be affected by a particular outage, the accepted industry practice is to adopt a VOLL (Value of Lost Load) of $2-5/kilowatt-hour (kWh), which represents an average value across the entire market." (U.S. Department of Energy, 2006). In Figure 3.6 the value of load curtailment is represented by $(q_{peak} - q'_{peak})$ * VOLL of $2-5/kWh.

Alternatively, the demand reduction may be obtained by emergency demand response programmes that activate demand response resources in merit order, using consumers with lowest benefit first. An example is contracts between consumers and their distribution company allowing the distribution company to make controlled demand cut-offs in emergency situations.

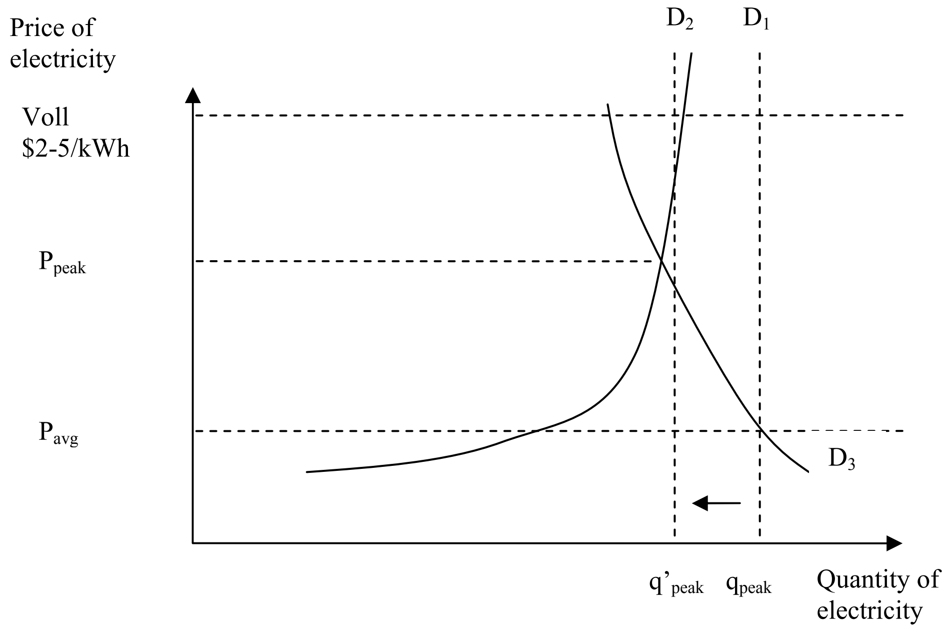


Figure 3.6   Demand response and security of supply.

Obtaining real-time balance between supply and demand in Denmark is the responsibility of the TSO in corporation with the TSOs in neighbouring countries. As mentioned in the introduction, the TSO ensures real-time balance by arrangements with power producers with flexible production and power consumers with flexible consumption. These arrangements can be tenders for ancillary services, e.g. primary (frequency activated) reserves or markets for regulating power, e.g. the market for secondary reserve (minute reserve) organised by the Nordic TSOs.

One reason for giving the TSO responsibility for the real-time power balance is that security of supply on the power market is seen as a public good. The two main characteristics of a public good are (Hardwick, Khan, Langmead, 1994):

1. *Non-rivalness in consumption,* i.e. the costs of the public good is independent of the number of consumers of the good.
2. *Non-exclusion,* i.e. once a public good is supplied to a consumer A, consumer B cannot be excluded from consuming it.

The costs of ensuring security of supply is to a large extent independent of the number of power consumers, because the level of power reserves needed to handle contingencies are largely independent of the consumption level. In addition, at present there is no possibility of real-time control of the power flow to specific customers (Stoft, 2002). Therefore, in a contingency situation, the TSO cannot limit the real-time power flow to specific customers according to their willingness to pay for a given security of supply level. There is a free-rider problem, and if security of supply was traded as a private good, some power consumers would buy too little security of supply counting on others to pay for an adequate amount. From a societal point of view, investments in security of supply would not be sufficient to ensure an optimal level of security of supply. Therefore, to ensure a reasonable security of supply level, society gives the responsibility to a public organisation.

Exercising market power may be interpreted as withholding production capacity or increasing supply prices. In Figure 3.7 this is equivalent to artificially shifting the supply curve to the left. If expressed demand curves are vertical lines or demand is inflexible, the effect of withholding supply is increasing the price from P* to P_{fix} and selling q* in the market, i.e. generating an additional producers' surplus of q* times (P_{fix}-P*). If consumers are flexible, demand reduces to q' and the price only increases to P_{flex}, generating a lower additional surplus for the producer and therefore reducing the incentive to exercise market power. However, as the amount demanded is reduced and the profit is a redistribution of welfare only, the welfare gain of this is negative (the shaded area in Figure 3.7).

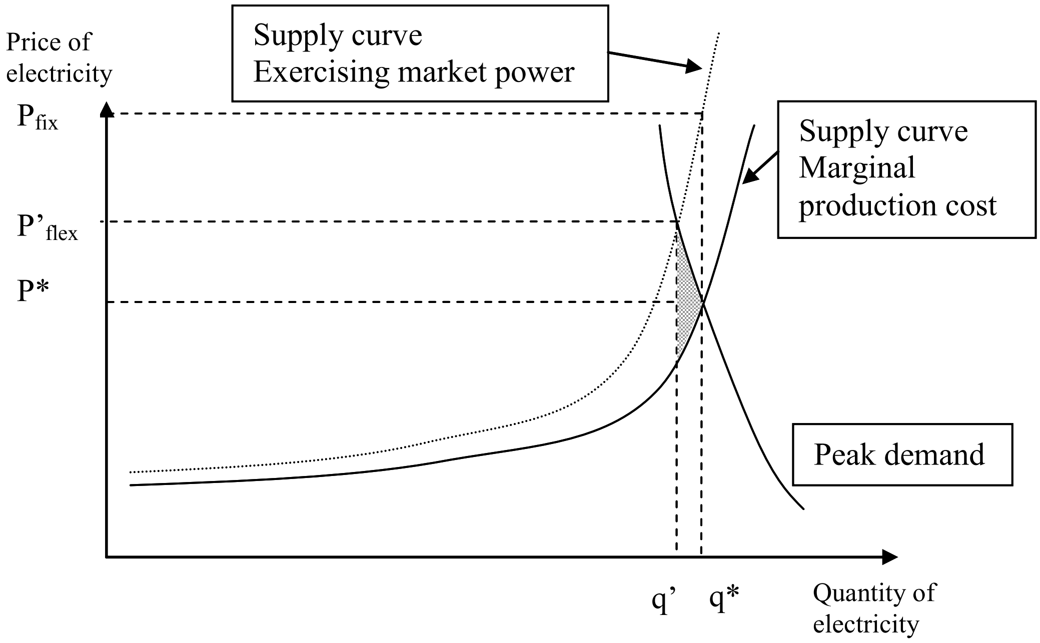


Figure 3.7 Demand flexibility and incentive for exercising market power.

A final value of demand response is the value of reduced investments in peak power units. This is achieved by reducing system peak demand and may be valued according to the marginal cost of capacity, i.e. the deferred costs of constructing new generation, transmission and distribution capacity. In general it is rather expensive to build power capacity to cover the demand in peak load hours that only occur a few hours every year. A 50 MW-single cycle gas turbine will require a power price of NOK 2/MWh to cover the investment costs, assuming that the number of full-load hours of the plant each year is 160 and the discount rate is 3% (Morthorst et al. 2005). Furthermore, the number of hours a peak load plant will be activated varies considerably from year to year. In the Nordic system the number of peak-load hours is related to the occurrence of low temperature periods, and the variation in the availability of other units, e.g. occurrences of plant outages. The variation in the number of operation hours each year make the risk premiums (and thereby the risk-adjusted discount rate) related to an investment in a peak load plant very high, and often such plants are only built if they can get a more steady revenue from selling system services (e.g. reserve power) to the TSO.

Summarizing, the value-creating elements of demand response are:

- Increased resource efficiency and welfare gains from consumers reacting to market prices.
- Reduced volatility in market prices and consumption and reducing the electricity bill for individual consumers (increased consumption at low prices (production costs) and reduced consumption at high prices).
- Increased security of supply.
- Reduced incentive for exercising market power; depending on the size and change in demand flexibility, the welfare gain may be positive, negative or zero, while electricity prices will decrease.
- Reduced investments in peak capacity decreasing the general price level.

However, the introduction of consumer response requires changes, some of which may be quite expensive. Chapter 4 will look more into the present organisation of markets, empirical observations and case studies of demand response programmes. Considering policy interventions, arguments focus on security of supply and reducing incentives for exercising market power.

4 Markets, empirical observations and demand response case studies

Before analysing empirical observations, this chapter gives an overview of markets and prices in the Nordic electricity market. Section 4.3 presents empirical observations concerning the present flexibility in electricity consumption, and section 4.4 presents a questionnaire analysing compensation rates required for residential users to accept interruptions in the power supply. Finally, section 4.5 looks at the issue of interval meters, and section 4.6 looks into tariff systems assuming interval metering.

4.1 Demand response in Denmark and the Nordic power market

The term "demand response" is often used broadly without specifying the time dimension. However, the issues when, where, for how long, and with which notification time demand response is needed, are important issues.

This section surveys these subjects with the Nordic power market as a case. It is shown that with respect to the different time dimensions, suitable prices and markets already exist in the Nordic power market.

By using the Nordic market case, a systematic grouping of the different characteristics of demand response is developed. This categorisation facilitates studies of the need, the effects, and the value of having demand response activities at the power markets and the possibility of using demand response to secure security of supply and a well-functioning market.

In the discussion of demand response it is often claimed that demand response can relieve critical problems with respect to security of supply. The problem of security of supply can be divided into several sub-problems according to the time dimension. Reduced availability and corresponding high prices of oil and natural gas are problems evolving over the next decades. Within a year, the problem is related to shortage of energy, e.g. due to a low precipitation season in a hydropower dominated area. On a daily time horizon, i.e. the day-ahead power market, the problem is shortage of available production capacity to cover planned power demand. A tight balance between production and demand gives high day-ahead power prices, and in the worst cases it reduces the amounts that consumers are allowed to buy on the day-ahead market. At a time horizon of one hour, it is possible to trade in e.g. the Elbas market on Nord Pool in order to reduce the imbalances between planned production or consumption on the day-ahead market and expected production and consumption. Within the actual operation hour, the problem is deviations of realised production and consumption from the planned production and consumption due to forecast errors or outages etc. At very short sight, within seconds, imbalance between actual production and consumption caused by these deviations is seen as changes in the frequency of the power network, which is counteracted by upward (or downward) regulation from primary reserves (frequency activated reserves). The primary reserves need to be relieved in order to be available for the next incident. This is done by activation of minute reserves (regulating power).

This means that the security of supply problem varies with the time dimension, and therefore, the corresponding markets, actors, price signals and available regulation mechanisms also differ according to the time dimensions.

At present, several markets exist in the Nordic countries covering different time dimensions between the market clearing (determination of the price and quantity) and the deliveries (www.nordpool.com).

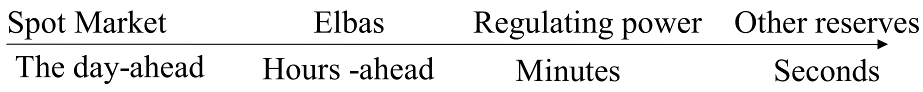


Figure 4.1 Markets and time dimensions in the Nordic electricity market.

Imbalances between supply and demand that may cause security of supply problems in the short term start at the level of the day-ahead market at Nord Pool. Even though the balance is re-established at the day-ahead level, new actions at the hour-ahead or reserves markets may be needed.

In addition to the physical markets, a financial market exists. At Nord Pool it is possible to “lock” the price for a future period, e.g. next year. This is like a bet on the average spot price next year. By using the financial market, traders can hedge their price risk. Hedging products related to price variations exist for days, weeks, months, quarters and years.

In the following, we look at demand response within days, hours, minutes, and seconds, using Eastern Denmark and the Nord Pool area as main cases.

Markets and demand response within days

The spot market is a day-ahead market where quantities and prices are settled on an hourly basis for a period of 12 to 36 hours ahead. A shortage of capacity is seen if there are hours with high demand compared to the production capacity. As an example, this may occur in situations with failures on major power plants, combined with a forecast of limited wind power production and high demand for electricity (low temperatures throughout the whole of the Nordic area where electric heating is part of the household demand). At the day-ahead market, the spot price for these hours will be high, giving a signal to the production side to deliver more capacity and to consumers exposed to the price to decrease demand.

Demand response is a matter of shifting consumption from high price periods to low price periods. However, in order to make use of the hourly prices, interval meters are preconditions for demand response in the day-ahead market. In Denmark, all consumers with an annual consumption of more than 100,000 kWh/year have interval meters. These consumers, representing half of the total electricity demand, can choose to buy electricity at a price related to the spot price, and thereby save money by adjusting their demand to prices. Currently, only a minority among the largest consumers use this opportunity.
In addition, communication and remote control systems can be used to reduce the need for manual interaction.

The cost of demand response in the household sector is dominated by investment in meters, communication and control systems.

A Danish demonstration project with electric heating (Kofod and Togeby, 2004) showed that it was possible to obtain demand response of up to 5 kW per involved household. There are 125,000 households with electric heating in Denmark. If 50% of these households with the largest consumption would accept contracts, this would amount to 260 MW on a cold winter day. In addition, other household appliances may be shut down for one or more hours, increasing the technical potential without any loss of comfort.

Markets and demand response within hours

The plans for production made in relation to the day-ahead market can be adjusted in the Elbas market (Electricity Balance Adjustment Service). Eastern Denmark introduced this market in August 2004 and in 2007 it will be introduced in Western Denmark. Elbas is open until one hour before delivery. It is an electronic real-time trading system where participants post offers and requests. A trade is made when two participants agree (anonymously). Demand can be sold or bought at Elbas.

Markets and demand response within minutes

At present response within minutes is covered by reserves. However, reserves are divided into:

- Fast reserves – activated within 15-90 minutes.
- Regulating power (upward and downward regulation) – activated within 15 minutes.

Causes of imbalances between supply and demand can be divided into:

- *Prognosis errors*, e.g. the difference between the actual wind power production and the production estimated in the day-ahead and hour-ahead markets. Prognosis errors may also be related to electricity demand or conventional production.
- *Failures* in power plants or transmission lines.

Reserves are used to re-establish the power balance and to restore the system in a safe state, where a new failure can be handled. This includes reducing the load on critical transmission lines or critical power stations. Activation of the fast reserves also has the function of releasing the instantaneous system disturbance reserves. This is a precondition for a safe system condition.

The regulating power is activated to maintain the frequency at 50 Hz, and the fast reserves are used to establish safe system conditions.

In Eastern Denmark, 600 MW of fast reserves and 75 MW upward regulating power are reserved by the TSOs for one whole year 2004. Furthermore, up to 75 MW upward regulating and up to 150 MW downward regulating power is reserved each morning for the next 24 hours. The reservation payment for 2005 is expected to be in the order of € 27,000/MW per year (Nordel, 2004).

If an area is exporting, it is not necessary to have local upward regulation, since it can be obtained by reducing the export. When an area is importing, it is not necessary to have local downward regulation, since it can be obtained by reducing the import. Reducing import and export is the same as activating the regulating power in the neighbouring countries.

All resources available for regulating power are listed on the common Nordic regulating power list (NOIS). When regulation is needed, the cheapest offer is activated. When there are no bottlenecks in the transmission system, the activated plant or consumer can be situated anywhere in the Nordic countries. For example, an imbalance introduced by less wind power than planned in Denmark can be counterbalanced by more production in Norway. The Swedish and the Norwegian TSOs have the role of monitoring the frequency and ordering regulating power.

Each potential supplier of regulating power offers individual amounts and activation prices, and the resources are activated in price merit order. Upward regulation has a price equal to or higher than the spot price (Skytte, 1999). In 2004 (7 Jan. - 24 Oct. 2004), the average price in Eastern Denmark was 10% higher than the spot price (€ 28.7/MWh) – see also Table 4.1. Activating upward regulation means that the TSO is buying electricity, i.e. some consumers decrease their consumption or some producers increase their production.

Downward regulation has a price equal to or lower than the spot price. In 2004, the average price was 13% lower than the spot price. Activating downward regulation means that the TSO is selling electricity. The market actors (the balance responsible parties) that have had an imbalance in relation to the amount they announced pay the cost of the regulating power. This payment follows the same direction as the total system. Imbalances that help the total system pay the spot price (i.e. no extra payment).

€/MWh	10%	50%	90%
Day-ahead market, Eastern Denmark	26.2	28.5	33.2
Up-regulation, more generation or less demand	26.9	30.0	34.6
Down-regulation, less generation or more demand	24.2	26.8	32.6

Table 4.1 Eastern Denmark; 10-90% quantiles of the prices in January to November 2004, in €/MWh.

As indicated in Table 4.1, the price variation in Eastern Denmark was quite limited in 2004.

The duration of activated regulating power is typically 0.25 to 3 hours. On average, the direction of the ordered regulation power changes four times per day.

If a unit fails, the demand and/or other production units have to cover the missing production. In Eastern Denmark, 600 MW of fast reserves are needed, of which 300 MW can be activated in less than 15 minutes, 60 MW in less than an hour and 240 MW in less than 1 hour and 30 minutes. At present, these reserves are contracted to large power producers.

Consumers with back-up generation (BUG) are another group of consumers that can respond within minutes. By generating part of their own consumption, they consume less from the central grid. The Danish TSO runs a demonstration project from 2003. In a tendering round with a goal of 25 MW consumption, they received offers at 50 MW from BUGs and 3 MW in consumption reduction. This resulted in contracts of 31 MW BUGs and 3 MW in consumption. Of these, an industrial cold store, a water treatment plant, a malt house and supermarkets are offering to reduce the electricity demand when ordered by the TSO (Nordel, 2004).

These resources must be aggregated into a group. Since the demand that can be reduced is related to the actual demand, the available effect can vary from hour to hour. An example is a water treatment plant that uses more electricity during the night when electricity is less expensive, i.e. the water treatment plant can offer a larger reduction of its consumption during the night than during the rest of the day. A dedicated computer system has been developed to handle these resources and is currently being tested (Energinet.dk 2006).

Markets and demand response within seconds

Within seconds there is a need for instantaneous system disturbance reserve. This need typically arises from failures in power plants or transmission lines, and the symptoms are that the frequency in the overall synchronous system rapidly decreases.

Increased production or decreased electricity demand must be activated very quickly in order to stabilise the system. Normal variation in the frequency is 50.0 Hz +/- 0.1 Hz. The instantaneous system disturbance reserves are activated in the frequency interval 49.9-49.5Hz. These services can be activated very quickly in order to secure that frequency does not get below a critical level. 50% of the effect must be activated within 5 seconds and the rest after 30 seconds (at 49.5 Hz). An example of a frequency drop and recovery is shown in Figure 4.2.

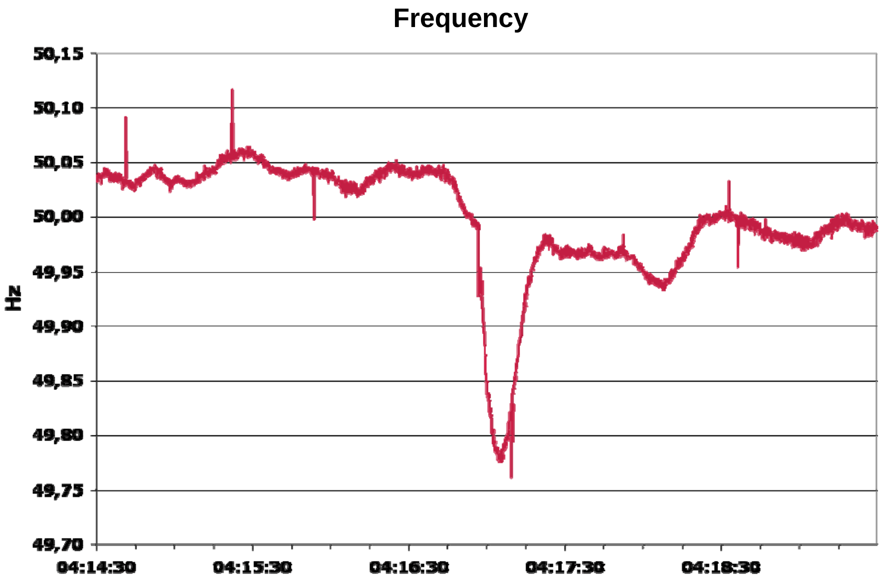


Figure 4.2 Example of a drop in frequency because loss of a power plant or transmission line. In less than 30 sec. reserves has re-establish the frequency in the normal range of 50 +/-0.1 Hz.

If the frequency does drop too much, the major power plants will automatically disconnect from the grid to protect their equipment and a blackout is threatening. The instantaneous system disturbance reserves are activated automatically and independently of location. This may lead to overload of transmission lines. Overloads can only be accepted for a limited time and other reserves must be activated manually to release the instantaneous system disturbance reserve (to prepare for a new failure) and to avoid overload of transmission lines.

Normally, the TSO enters a one-year contract with a price for always having access to this type of reserve. Currently, in Denmark, the TSO buys from local large producers. In Eastern Denmark, the TSO has at present contracted 100 MW for this type of reserve, which must be local.

On the production side, the power plants can be operated below their maximum production, and in this way they can increase production at short notice. Another source is DC-connection maintaining a reserve for this purpose, e.g. at the Kontek Link between Zealand and Germany 50 MW is kept as reserves.

On the demand side, demand that can be switched off without major inconveniences may be used for this purpose, e.g. consumption with thermal storage – ovens, refrigerators, industrial cold stores or certain usages of pumps.

In Finland, industrial processes are used for these reserves. The companies have yearly contracts with Fingrid (Nordel, 2004).

In New Zealand, water heaters are used for these reserves (EnergyWise, 2003). In this case, a signal is sent by the power lines using ripple control technology. Although communication is needed from the central frequency sensor to the individual water heater, the lag time is only 6 seconds. An auction is held each month. The reservation price depends on the need for reserves and the possible suppliers. The grid company acts as an intermediary on behalf of the individual houses and the TSO. The typical effect is 1 kW/household. In 2002, the average payment was € 15.5 per household per year.

Pacific Northwest National Laboratory and California Energy Commission have studied the possibilities of using a broad range of appliances as frequency controlled reserves, e.g. water heaters, air conditioners, refrigerators, freezers, etc. (California Energy Commission, 2003). An electronic card to control such equipment can be manufactured for around € 15.5. The card is designed with a set-point and a random variation from this. In this way, a smooth regulation is obtained without any communication to the individual equipment.

The Danish TSO supports a research project concerning frequency-controlled equipment in households and businesses. This includes an evaluation of the desirable amount of such equipment. Since the consumption by the equipment may change over time, the reserves will also change. New procedures must be developed to manage this aspect.

With respect to the duration, the reserves must be active until they can be substituted by other reserves. The other reserves commence after 10-15 minutes (see Demand response within minutes above). The duration of the activation is often very short, e.g. 1-5 minutes.

Categorising demand response

In the Nordic power market prices and markets for different time dimensions exist, and these prices and markets are suitable for the introduction of more demand response.

Before using this splitting in time dimension to categorise demand response, we notice that the survey also revealed that:

- The price of demand response varies for each second of the year.
- The price varies with the notice (e.g. day-ahead market or regulation power with 10-15 minutes' notice).
- The trading volume varies for each market.

The day-ahead market (Nord Pool Spot) has a large trading volume, whereas the regulating power market at Nord Pool has a much lower trading volume. A supplier of demand response can almost be sure to be asked to deliver in the spot market, if he offers a favourable price. In the regulating power market, he will only be called for if there is a need for up-regulation (reduced demand) or down-regulation (increased demand). Regulation power is not activated in all hours. Approximately, half of the calls for regulating power are for up-regulation and half of the calls are for down-regulation. The benefit of trading at the regulating power market is that the prices are higher than at the spot market. This is illustrated in Table 4.2 showing the size and economic turnover of the different markets in the Nordic area.

Market	Commercial balance established Day-ahead spotmarket	Commercial balance established Elbas	Technical balance adjusted by the TSO Regulating power reserves
Energy turnover	98.90%	1%	0.10%
Economic turnover	84.00%	1%	15%

Table 4.2 Markets, size and economic turnover in the Nordic area. Energinet.dk, 2006.

Table 4.3 illustrates different demand response activities and problems within seconds, minutes, hours and days.

	Seconds	15 minutes	Hours	Days
Problems:	Fast decrease in frequency	Maintain the frequency and system conditions	Adjustments of planned production	Allocation of demand and production
Causes:	Failures in plants or transmission lines	Prognosis errors Failures	Prognosis errors Excess capacity	Where to produce? Shortage of capacity Imbalances in the spot market
Markets:	Contracts Ancillary service Instantaneous system disturbance reserves	Fast reserves Regulating power Contracts	Elbas hours ahead Real-time pricing Dynamic pricing Contracts	Nord Pool Spot Time-of-use tariffs
DR actions:	Automatic activation of reserves. Disconnection of consumption	Consumers active in the regulating power market Contracts between TSO and consumers	Adjust central production Own production Consumers active in the balance market	Load management Consumers active in the spot market

Table 4.3 Demand response actions and time dimensions in the Nordic markets.

The first three rows of the table indicate the characteristics of the different security of supply problems and markets. The last row indicates possible demand response actions that can be taken within each time dimension.

With a notification within seconds, one of the possible demand response actions is disconnection of consumption, e.g. based on local frequency measurements and without any additional communication. The price of disconnecting consumption within seconds is often agreed upon in advance. With a longer notification time, the amount and prices of demand response can be determined simultaneously.

Table 4.3 shows that demand response is not only characterised as short-term response in demand to the prices. Other important elements are:

- Notification of the necessary demand response action.
- Duration of the demand response.
- The frequency at which the demand response activity is called upon.

The notification of the action refers to the discussion above, where the action could be noticed in the day-ahead market (Nord Pool spot market) with the physical demand response action on the following day, and likewise for notifications within hours in Elbas, etc. In general, the shorter the notification time is, the more costly the demand response activity is (Skytte, 1999).

The duration of the activity refers to the period of time the activity must be active. The consumers might look at two similar activities with different durations as two separate activities, which they value differently. For example, a short interruption of the electric heating in a household might cause less comfort losses than a longer interruption. In addition, a consumer that can react within seconds might only be able to reduce his consumption a few minutes before he has to increase the consumption again. When these minutes have elapsed, other reserves may take over, if necessary. Thereby, the use of demand response instruments might be seen as a portfolio of different instruments in connection with a specific security of supply problem.

The frequency of the activities refers to the number of times a demand response activity is called upon. A consumer may be more dedicated to supply a demand response activity that might be called upon 10 times per year at a price of € 10/time, compared to supplying a demand response activity that might be called upon 1 time in five year at a price of € 500/time – even though, for both activities, the expected revenue is € 500 per five years.

The above discussion shows that demand response varies with the time dimension. Hence, also the corresponding markets, the actors that are relevant in connection with the different problems, the price signals and the available regulation mechanisms differ according to the time dimensions.

A demand response activity that can respond within seconds and with a maximum duration of a few minutes is not very useful to ensure security of supply at an hourly basis. Therefore, the price and value of this type of demand response is more or less zero at the hourly basis. However, the same demand response activities might have a high value when it comes to responses within seconds.

It is also essential to clarify which consumers can supply what kind of demand response. Not all consumers are or need to be flexible. It is like having base and peak load power plants. Neenan, Boisvert and Cappers (2002) argue that only a small fraction (5%) of all consumers need to respond to the electricity prices in order to avoid most of the security of supply problems.

In conclusion, the survey reveals that with respect to the different time dimensions, suitable prices and markets exist in the Nordic power market, and Table 4.3 shows the importance of distinguishing between the time dimensions. It also shows that the value of having a flexible consumption side with demand response activities can be measured in the markets – not only in a single market (e.g. the spot market), but in several markets.

4.2 Prices and demand response options

In a market, prices act as signals for an efficient allocation of resources. In a market with time-varying marginal production costs the optimal price in each period is where marginal consumer utility meets marginal production costs (see chapter 3). With interval metering it is possible to set prices equal to the marginal production cost, thereby giving the consumers the possibility to change consumption according to their marginal utility of consuming electricity. However, introducing interval metering and marginal pricing only makes sense in markets where consumers are able/have time to react to prices, i.e. at daily and hourly markets as mentioned in the previous section. In shorter markets - seconds and minutes - other demand options like direct load control, interruptible service etc. are available. These options may be both voluntary and price driven and may include additional incentive payments.

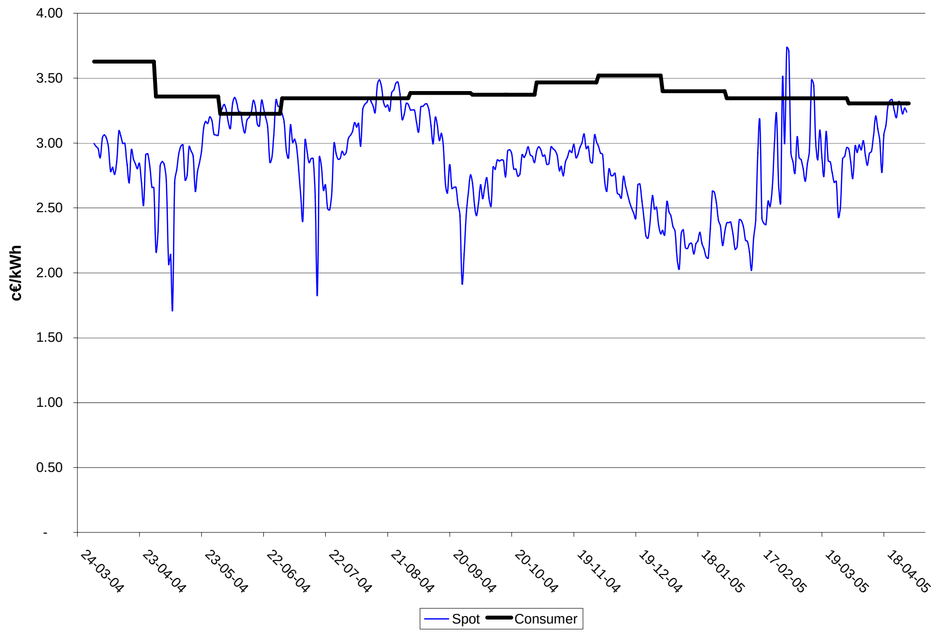


Figure 4.3 Consumer prices (Denmark) and wholesale price (Elspot system price) from April 2004 to April 2005 (source: nordpool.com and energitilsynet.dk).

Price-based demand response options

Historically electricity consumption has been metered yearly - for large consumers monthly/quarterly - implying a flat tariff over the year, quarter or month. This is illustrated in Figure 4.3. Introducing interval metering at hourly intervals gives the option to vary tariffs according to hourly variations in marginal costs of production or in Denmark according to prices at the Nord Pool exchange. However, for consumers to follow price developments in the market is not without costs. The most commonly implemented price-based demand response options are time-of-use tariffs (TOU), critical peak pricing (CPP) and real-time pricing (RTP) addressing different problems in the market and requiring different engagements by the consumers.

A time-of-use tariff gives information on systematic variations in daily/weekly prices/costs of production and defines blocks of hours with different rates reflecting average costs during each block. Typically, the 24 hours per day are grouped into three blocks: low, normal and peak hours. Also weekly variations may be included, e.g. working days and week-ends, where week-ends only have low or normal hours. The purpose of using TOU tariffs is load shifting, decreasing consumption at peak hours and increasing consumption in normal and low price hours. Compared to average pricing, time-of-use tariffs aim to reduce welfare losses by introducing levels of average pricing. In Figure 4.4 this means reducing the aggregated area of the welfare loss triangles. Typically, the tariff is pre-determined for a year in advance, and once determined, consumers know the rules and do not have to follow hourly price changes in the market.

Critical peak pricing (CPP) focuses at periods when marginal production costs and prices in the market are very high, either due to very large demand or due to lack of production capacity, and aim at reducing demand in high-price periods by super-imposing a pre-specified high rate. Normally, CPP rates are super-imposed on either a TOU tariff or a time-invariant rate. Utilities or retailers trigger CPP rates and call on consumers to react at relatively short notice, often for a limited number of days/hours per year. Often, consumers are given a price discount during non-CPP periods. CPP programmes require that consumers receive information when CPP rates are triggered and are able to react to these.

In systems with real-time pricing the price of electricity directly reflects the market price, typically on an hourly scale, determined on a day-ahead or an hour-ahead basis. On an hourly market, RTP removes the welfare losses associated with other tariff systems. However, to make sense RTP requires consumers to follow price developments in the market and carry the costs associated with this.

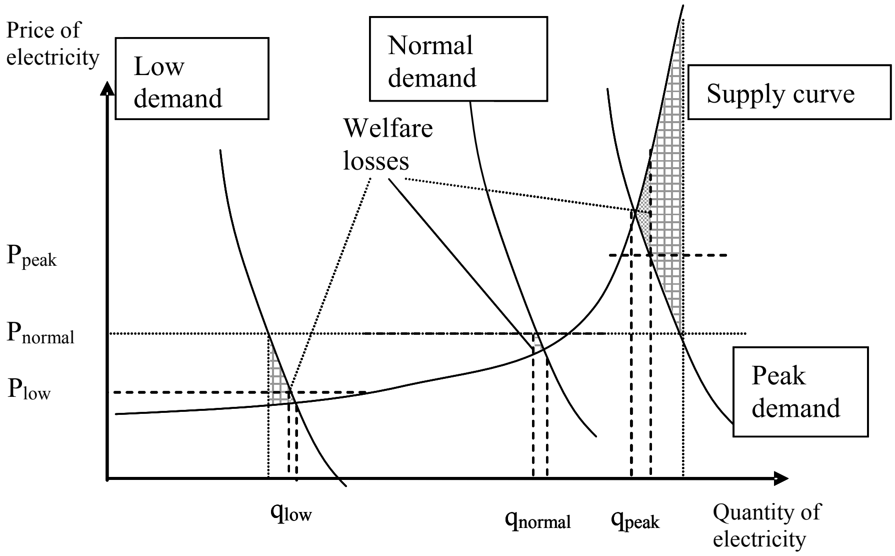


Figure 4.4 Welfare losses using average and time-of-use tariffs.

Components of the electricity price in Denmark

For the consumer, the cost of electricity can be divided into energy, transportation, taxes and other costs.

The tariffs to the transmission system operator (TSO) and the distribution system operator (DSO) cover transport of electricity, including losses and network investments, but also metering, system operation and public service obligations for research and activities for promoting energy savings.

Typical profiles for the cost of electricity in Denmark are given in Table 4.4.

	With interval meter				Without interval meter
	1	2	3	4	5
Energy	Real time	Real time	Flat	Flat	Flat
TSO/DSO	TOU	Flat	TOU	Flat	Flat
Taxes	Flat	Flat	Flat	Flat	Flat
VAT	25%	25%	25%	25%	25%

Table 4.4 Typical profile of electricity prices in Denmark. "Flat" means a fixed time-invariant rate per kWh. VAT is a percentage of other costs. VAT is not paid by companies.

End-users with interval meters (all end-users with a yearly consumption above 100,000 kWh) can choose to buy electricity with a real-time component, e.g. a spot price related to the Nord Pool day-ahead price for each hour (column 1 and 2). Among electricity intensive industries this has some popularity. A survey of 25 large Danish companies with a total consumption of 1.6 TWh/year showed that 50% of the consumption was bought at fixed prices and the rest at the spot price (some with a maximum price). Often the choice of spot price contracts is combined with a financial contract, limiting the price risk while maintaining the incentive for demand response (Dansk Energi Analyse and Norenergi, 2005). Many consumers with an interval meter choose to buy electricity at a flat tariff. The actual tariff is typically negotiated on the basis of the load profile in a former period, and companies with a large share of demand in off-peak periods often negotiate a lower price.

Dependent on the location of the company the tariffs for the TSO/DSO may be a flat or a time-of-use (TOU) tariff. The TOU-tariff typically is a three part tariff, defining a peak, a shoulder and an off-peak tariff. TOU price levels are typically adjusted annually.

Table 4.5 gives an example of the TOU tariff for the TSO/DSO for two different grid areas. In SEAS the peak tariff is twice the off-peak tariff. Sydvest Energi has a flat tariff. The TSO/DSO's are free to choose the form of tariff.

Øre/kWh	Off-peak	Shoulder	On-peak
TSO/DSO (SEAS-NVE 0.4 kV)	18.00	24.38	31.48
TSO/DSO (SEAS-NVE 50/10 kV)	9.70	13.95	18.07
TSO/DSO (Sydvest Energi)	15.11	15.11	15.11

Table 4.5 Examples of TSO/DSO tariffs for a costumer with interval meter (0.4 kV) in the SEAS-NVE or Sydvest utility area (December 2005).

For households the energy part of the electricity bill is 19% of the total costs, only (see Table 4.6). The tariff for TSO/DSO (including subscription) is 24%, and the rest is VAT and taxes.

Taxes are flat (66.6 øre/kWh for households). The levels of taxes vary with end-user (highest for households). For companies, taxes vary according to the purpose of the use. Reduced levels of taxes are allocated to energy intensive end-uses, while electricity for heating is taxed with a higher rate. VAT is 25% of the value (see Table 4.6), however, for companies VAT is refunded.

Price, øre/kWh	Households 3.5 MWh	Small companies 160 MWh	Large companies 300 GWh
Subscription	16.7 (9%)	2.1 (3%)	0.0 (0%)
Grid payment (TSO/DSO)	27.1 (15%)	24.4 (35%)	20.3 (45%)
- Public Service Obligation	7.9	7.9	7.8
- Transmission	6.0	6.0	5.9
- Distribution	13.3	10.6	6.5
Electricity	33.7 (19%)	32.3 (46%)	24.8 (55%)
VAT and taxes	102.6 (57%)	11.0 (16%)	0.4 (1%)
- CO2-tax	9.0	9.0	0.3
- Other taxes	57.6	2.0	0.1
- VAT	36.0	0.0	0.0
Total	180.0 (100%)	69.8 (100%)	45.4 (100%)

Table 4.6 Typical electricity prices for categories of consumers in Denmark. (Subscription is a fixed payment, here divided by the electricity consumption. Energitilsynet, November 2005).

Concluding, in Denmark households face a time-invariant electricity rate of which, only 19% is related to the costs of producing electricity, 57% is VAT and taxes. For large consumers with interval meters, some are exposed to a real-time price component for the energy part - other consumers choose a time-invariant, but negotiated rate. In addition, some large consumers face a TOU rate for the grid payment – other consumers have a time-invariant grid payment. Except for the critical peak pricing the Danish tariff system includes elements from the tariff systems mentioned, i.e. time-invariant rates, TOU and real-time pricing.

An example of a combined TOU and CPP system is the French Tempo tariff. For years EdF has offered a system with a day (from 06 to 22) and a night tariff varying with three “colours” of the day. 500,000 customers are using the Tempo tariff, including 350,000 households with electric heating. Part of the system is that maximum 22 of the most expensive days and maximum 43 of the medium expensive days will occur per year.

Information about the “colour” of the day is, the day before, announced by e-mail or SMS. A study has documented a 1 kW reduction of demand per house at the highest prices (Nordel, 2004).

(€/kWh)	Blue days 300 days	White days 43 days	Red days 22 days
Night	0.0446	0.0907	0.1682
Day	0.0553	0.1075	0.4702

Table 4.7 Tempo tarff (particuliers.edf.fr/rubrique112.html).

Another example of a CPP system is the GoodCent Select system used by Gulf Power in Florida. This system is a TOU tariff with 3 parts combined with an additional step with an extra high price. The expensive step can occur in maximum 1% of the time.

As part of the tariff, a communication system, which can disconnect equipment, e.g. air conditioners at high prices, is offered. The monthly fee for the tariff and the communication gateway is $4.95. It has been documented that with high prices demand is reduces by 2 kW per household (Nordel, 2004).

	Price, US cents per kWh	Duration per year
Low	5.4 cents	28%
Medium	6.7 cents	59%
High	11.2 cents	12%
Critical	32.1 cents	1%

Table 4.8 GoodCent tariff. www.southerncompany.com/gulfpower/residential/select.asp.

Incentive-based programmes for demand response

In addition to voluntarily reaction to price schemes, demand can also be used in relation to incentive-based programmes. In these a reservation payment is agreed upon and demand *must* be reduced or increased when called.

Most incentive-based demand response programmes focus on security of supply and the time scale minutes to seconds giving TSOs the option to cut-off demand or call-on firms with emergency back-up generators to start these and reduce their demand during system contingencies. Strictly speaking, one may argue that starting-up emergency back-up generators by consumers is a supply-side option, but seen from the TSO the effect is similar to a demand reduction and is in the market seen as such.

Incentive-based programmes are elaborated in many ways. Some examples are:

Direct load control programmes or *interruptible/curtailable service* where e.g. large consumers agree to reduce consumption during system contingencies, typically with a notice of maximum 15 minutes. A Danish example on this is the FLEX demonstration project where a brewery, a cold store, an ice skating ring, a supermarket and a water supply plant and a number of back-up generators has agreed to reduce demand when called upon by the TSO. These resources were used as regulation power.

Frequency controlled demand response programmes where specific electrical appliances automatically are disconnected for a shorter time during system contingencies and drops in the net-frequency. In Britain and Finland industrial demand is used as frequency controlled reserves, e.g. metal works, industrial ovens, or pumping systems. Considering household appliances, e.g. freezers, refrigerators, and water heaters may without problems be disconnected for a short time. Frequency controlled disconnection has the advance of giving a very quick response (seconds) and may be used until other reserve capacity can be started.

4.3 The intensity of consumer response to price changes

In chapter 3 presenting the theoretical background for demand response, the intensity of consumer response to price changes is represented by the slope of the demand curve. (see, e.g. Figure 3.1) As mentioned in chapter 3, the slope of the demand curve is a crucial parameter in determining price, quantity and welfare effects of various price-based demand response options and numerous empirical studies examine the size of this.

A normalised measure of price-response is the own-price elasticity, defined as the percent change in electricity usage when the price of electricity is changed by one percent, i.e. an own-price elasticity of -0.2 implies that electricity usage decreases 0.2% when the price of electricity increases 1%.

Related to studies of TOU rates another normalized measure of price-response is a substitution-elasticity defined as the ratio of peak to off-peak electricity usage in response to a one percent change in the ratio of off-peak to peak electricity prices. This is a measure of load shifting, measuring the propensity of consumers to shift electricity usage from peak to off-peak periods in response to changes in the relative off-peak to peak price of electricity.

A survey of empirically observed own-price and substitution elasticities is given in U.S. Department of Energy (2006). Not surprisingly, estimates in different studies vary considerably reflecting methodological differences, consumer characteristics and design of programme.

Using TOU data for residential and small commercial users, the average substitution elasticities found is to be 0.14 (range from 0.07 to 0.21), and the average own-price elasticities is -0.30 (range from -0.1 to -0.8). In the own-price elasticity studies also CPP data was included.

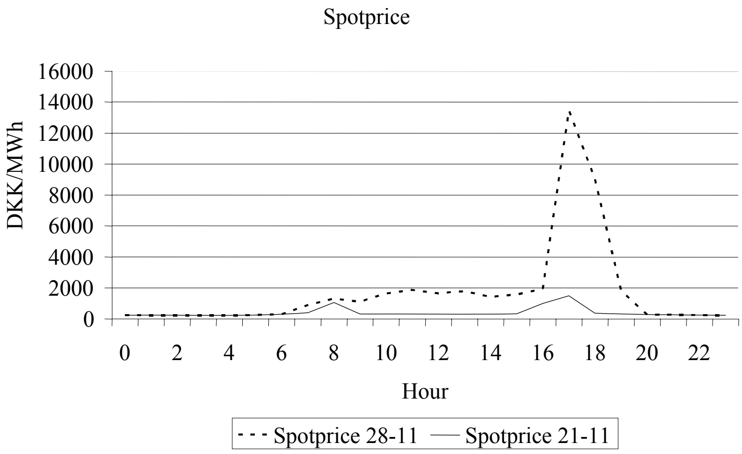
Using day ahead data, estimated own-price elasticities range from 0 to -0.3. For residential consumers a study at Commonwealth Edition in Illinois estimated own-price elasticities of -0.04 in 2003 and -0.08 in 2004. However, hourly prices were low in the two years and response may be higher under a high price-regime. Other studies focusing on segments of consumers and time of the day conclude that large industrial consumers have the largest elasticity while small industrial consumers with limited experience with RTP had the lowest elasticity (-0.06 or numerically lower). Also over the course of the day elasticities vary considerably, however no specific values are given in U.S. Department of Energy (2006).

Concluding a very large range of elasticities is observed.

Residential users tend to have a lower elasticity when exposed to RTP, than when exposed to TOU rates. An explanation may be that exposed to a TOU rate consumers know and understand the prices and can react by changing routines. When exposed to RTP the information costs are high – if the reactions are not streamlined by using enabling technology.

Large industrial consumers tend to have the highest elasticity and there is some evidence that the elasticity is larger at high prices than at low prices. This indicates that for some consumers a threshold-price has to be reached before significant demand response is observed. Smaller industries and consumers with little experience in RTP have a much lower elasticity.

Looking at observations in the Danish market, at the national level demand response to prices is extremely limited. This may be illustrated by Figure 4.5 showing prices at the spot market and consumption in Eastern Denmark, two Mondays in November 2005. November 28 the price reached an extreme peak of DKK 13,469/MW, about 60 times the normal price-level, but compared to the consumption a week before, consumption was almost unchanged.



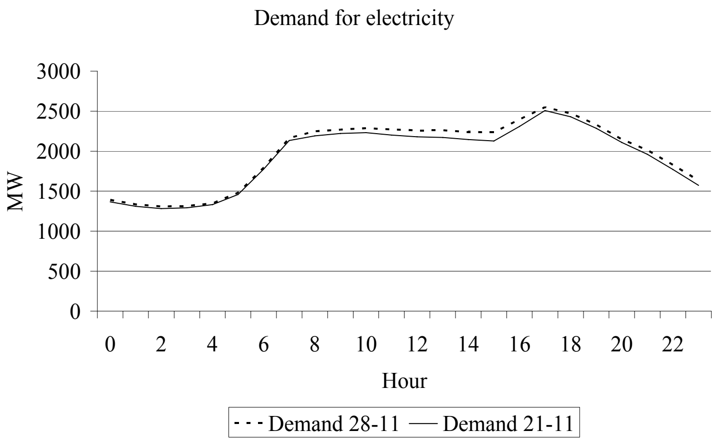


Figure 4.5 Electricity demand and spot prices in Eastern Denmark on two Mondays in November 2005.

An explanation of the lack of demand response to even drastic price changes in the market is that most of the consumers are exposed to an average rate and do not see the price peak. In hour 17 and 18, half of the electricity usage is by residential consumers not exposed to hourly prices in the market. For consumers with hourly metering, (not all of these are exposed to hourly prices) the consumption was marginally lower in hour 18 on 28 November. The consumers who were exposed to hourly prices did decrease consumption as a reaction to the drastic price increase on 28 November. However, in relation to the total market the effect was minor and neutralized by other consumers increased usage.

Looking at a few large consumers exposed to hourly prices in the Nord Pool market, hourly price elasticities are estimated in (Andersen, 2006). The general conclusion form these estimations is that expressed elasticities for Danish consumers is very low (between -0.005 and -0.1), and it is extremely difficult to reveal theoretical sound elasticities. This may be due to statistical problems or problems with assumptions in the model estimated, e.g. assuming the same elasticity for all hours and price-levels. However, low elasticities may be explained by the fact that consumers are new in the market, lack experience in reacting to high prices, lack enabling technologies or the cost of changing consumption is too high except when prices reaches a threshold. Another explanation may be, that the consumers analysed chose the tariff related to the Nord Pool price as they evaluated this to be the cheapest in the long run.

The importance of the price elasticity may be illustrated by looking at the welfare gains in Figure 3.5 introducing hourly pricing instead of average annual tariffs. That is, calculating the area of the triangles ABC (A'B'C') for each hour in a year. Using hourly prices at the Nord Pool, the distance AB (A'B') each hour equals the difference between the hourly price and the average price over the year (called Δp). The change in the quantity consumed each hour may be calculated assuming different demand and supply elasticities (calling the change Δq)[2]. For the years 2001 to 2004 the welfare gain of introducing hourly prices is shown in Table 4.9. The assumptions behind this calculation are:

- Supply and demand curves have constant elasticities in the relevant intervals.
- In 2001 to 2004 all Danish consumption is exposed to average pricing.
- The price paid by consumers is calculated from the Nord Pool price plus average additions for subscription, grid-payment, and taxes shown in Table 4.6 (that is, 146.3 øre/kWh for households, 37.5 øre/kWh for small companies and 20.6 øre/kWh for large consumers. For households the addition includes VAT. In this simplified calculation the VAT is added as a fixed value.). This influences the size of Δq via a scaling factor on the price.
- At each hour, each of the consumer categories consumes 1/3 of the total usage. This is a somewhat dubious assumption as households use electricity in the morning, late afternoon and evening, mainly, while most of the usage by industry is at normal working hours.

Looking at the welfare gains in Table 4.9, assuming an elasticity of -0.05 on average over the four years DKK 10.6 million per year is gained.[3] However, due to different price-volatility in the four years, the gain varies considerably between years. In 2003 price volatility was large and in 2004 the prices were relatively stable. The welfare gain changes a factor 6 between 2003 and 2004. The relation between the welfare gain, the price volatility and the assumed price elasticity is shown in Figure 4.6 (The x-axis of the figure is the standard deviation in the Nord Pool price calculated for the four years). The welfare gain increases with increased volatility of prices. However, due to different supply elasticities for different price (cost) levels the relation is not linear.

[2] Equations for the determination of Δq and the calculation of the welfare triangles ABC (A´B´C´) is developed in annex I.

[3] An elasticity of -0.05 implies that in an hour where the consumer price is twice the average, consumption is reduced by 5%. An average consumer pays app. 68 øre/kWh in VAT, taxes, grid payment etc. plus an average Nord Pool price of app. 30 øre/kWh; in total app. 98 øre/kWh. A doubling of the consumer price gives a price of 1.96 øre/kWh equivalent to app. a 5 doubling of the Nord Pool price.

	Demand price elasticity					Standard deviation in Nord Pool prices, DKK/MWh
	-0,005	-0,050	-0,100	-0,150		
2001	1	6	10	13	MDKK/year	97
2002	2	17	29	39	MDKK/year	167
2003	2	17	29	39	MDKK/year	187
2004	0	3	5	7	MDKK/year	62
Average	1	11	18	24	MDKK/year	

Table 4.9 Welfare gain in 2001 to 2004 assuming different price elasticities.

Figure 4.6 Dependency of welfare gain on price elasticity and price volatility. Trendlines are inserted.

Looking at which parts of the price scale that contribute to the total welfare gain, Table 4.10 shows the welfare gain coming from prices below the average price at Nord Pool, between the yearly average price and two times the average price and above two times the yearly average price.

	Demand price elasticity				
2003	-0,005	-0,050	-0,100	-0,150	
Below average price	1	5	10	15	MDKK/year
Average to two times average price	0	2	3	4	MDKK/year
Above two times average price	1	10	16	20	MDKK/year
Total welfare gain	2	17	29	39	MDKK/year
2004					
Below average price	0	2	3	4	MDKK/year
Average to two times average price	0	1	2	2	MDKK/year
Above two times average price	0	0	0	0	MDKK/year
Total welfare gain	0	3	5	7	MDKK/year

Table 4.10 Contribution to welfare gain in 2003 and 2004.

The conclusion from Table 4.10 is that in years with large price variations and large welfare gains, most of the gain (app. 60%, but varying with the demand-elasticity) comes from peak price periods, while in years with smaller price variations and small welfare gains the contribution from prices below the average price is a substantial part of the total welfare gain. That is, large welfare gains are mainly related to periods with high prices in the Nord Pool market.

Finally, looking at the implication of "price-additives" (VAT, taxes payment for grid etc) Table 4.11 shows the contribution from categories of consumers. It is assumed that each hour, each of the consumer categories use 1/3 of the total consumption and the only difference between the three categories is the size of the "price-additive".

		Demand price elasticity				
	Price-addition	$\alpha 1$	$\alpha 2$	$\alpha 3$	$\alpha 4$	
	DKK/MWh	-0,005	-0,05	-0,10	-0,15	
2003						
Large consumers	207	3	24	40	52	MDKK/year
Small companies	375	2	19	32	43	MDKK/year
Households	1463	1	9	16	22	MDKK/year
Total	682	2	17	29	39	MDKK/year
2004						
Large consumers	207	0	4	7	10	MDKK/year
Small companies	375	0	3	5	7	MDKK/year
Households	1463	0	1	2	3	MDKK/year
Total	682	0	3	5	7	MDKK/year

Table 4.11 Welfare gain and consumer categories (Price-additives).

As seen from the table, a large fixed "price-additive" for residential users implies a small relative price-variation and therefore a limited welfare gain from exposing consumers to varying prices. For large consumers, paying a much smaller fixed price-additive, relative price variations are much larger and therefore the potential welfare gain much higher. If in addition, it is evaluated that large consumers have a higher elasticity than residential consumers, to obtain demand response exposing large consumers to varying prices seems a reasonable starting point for the introduction of interval meters.

4.4 Evaluation of directly controlled power interruptions.

For many consumers the cost of manually following the development in the market price may exceed the potential benefit from demand response. For these consumers a scheme for automated controlled interruptions at system contingencies and peak prices may be a favourable alternative. Typically, consumers in direct control schemes receive a participation payment for a predetermined maximum number of interruptions per year and a maximum duration of each interruption and the effect is measured as the load reduction per consumer per incident. In some schemes the consumer has the option to over-ride the interruption if the timing is inconvenient. A survey of schemes targeting residential consumers with air conditioning and water heating is given in U.S. Department of Energy (2006).

Targeting Danish residential users with a dishwasher, a washing machine and a dryer, a pilot study of how to compensate consumers for disconnecting the appliances for different durations and number of timer per year is documented in Lassen and Jensen (2005). Using a Random Utility Model and Discrete Choice Experiments to give data revealing individual marginal benefit (expressed trade offs between sets of choices), the pilot study aims to find appropriate compensation levels for controlled disconnections. Questionnaires were sent to 600 consumers living in single family houses without electrical heating and having an annual consumption between 5000 and 6000 kWh. (i.e. more than the average demand in single family houses of 4000 kWh/year). 189 consumers responded giving a response rate of 31.5%. Besides questions revealing preferences related to the frequency -, duration of interrupts and compensation levels, a number of background data, e.g. number and use of appliances, demographic and socioeconomic information were included. Focusing on questions revealing preferences, the set of choices given to the consumers are summarized in Table 4.12.

Pair	Duration	Number of interruptions (frequency) pr. year	Compensation DKK/year
1	3 hours 15 minutes	2-3 times 12 times	25 1000
2	3 hour 15 minutes	12 times 30 times	100 800
3	1 hour 3 hours	30 times 2-3 times	25 800
4	15 minutes 1 hour	12 times 30 times	25 250
5	1 hour 3 hours	2-3 times 12 times	100 250
6	1 hour 3 hours	12 times 30 times	500 1000
7	15 minutes 3 hours	2-3 times 30 times	250 500
8	15 minutes 1 hour	2-3 times 12 times	500 800
9	15 minutes 1 hour	30 times 2-3 times	100 1000

Table 4.12 Sets of choices posed to the consumers (translation from Lassen and Jensen, 2005).

This defines three categorical variables:

- Compensation levels in DKK 25, 100, 250, 500, 800 and 1,000
- Duration of each interruption (0.25, 1 and 3 hours)
- Frequency (interruptions per year 2-3, 12 and 30).

Specifying and estimating a conditional logit-linear model on the collected data, acceptable mean compensation levels for combinations of duration and frequency are given in Table 4.13[4].

DKK		**Frequency** (Number of timer per year per appliance)		
		2-3	12	30
Duration	0.25 hours	256	409	419
	1 hour	334	487	497
	3 hours	556	709	1120

Table 4.13 Estimated mean compensation levels.

To enter a contract, allowing the system operator to disconnect the three appliances 12 times each of 1 hour duration, consumers require a mean compensation of DKK 487. The compensation levels in Table 4.13 appear very high if interpreted as costs of contracting consumers for interruptions of the three appliances. However, the standard deviation on the estimates is relatively high, that is, to enter a contract some consumers require a much lower level of compensation.

Looking at combinations of duration and frequency the data reveal that for durations of 0.25 and 1 hour, frequencies of 12 or 30 times per year the required compensation is almost the same, while for durations of 3 hours compensation requirements increase. Converting to hours of interruption for each appliance, as seen from Table 4.14, the cheapest is to sign contracts disconnecting each consumer often and for a long time, i.e. a threshold compensation is required for accepting a contract. However, depending on the problem in the market, long interrupts may not be an optimal solution, e.g. if the problem is short-term security of supply.

DKK/hour		**Frequency** (Number of timer per year per appliance)		
		2-3	12	30
Duration	0.25 hours	136	45	19
	1 hour	45	14	6
	3 hours	20	7	4

Table 4.14 Estimated mean compensation levels per hour disconnected for each appliance[5]

[4] A detailed description of the model, estimations and calculation of acceptable mean compensation levels is given in Lassen and Jensen (2005).

[5] From the questionnaire it is specified, that each appliance may be disconnected individually, i.e. a frequency of 12 times per year implies up to 36 interrupts per year. Therefore, the compensation level for 12 times, 1 hour interrupts is 487/(12*3)=14. The figure 487 comes from Table 4.13.

Focusing on consumers accepting low compensations, Table 4.15 shows that 8% of the enquired consumers accept a compensation of DKK 25 for being disconnected 2-3 times per year with 3 hours duration per disconnection.

Compensation DKK	Duration hours	Frequency Times per year	% accepting an agreement
25	3	2-3	**8%**
500	3	30	**7%**
250	3	12	**20%**

Table 4.15 Consumers accepting low compensation levels.

Scaling with the number of washing machines, dryers, dishwashers and average effects in use of the appliances, 8% gives a capacity of 120 MW available at about DKK 0.60/kWh. However, only part of this is available at any specific time. Applying use-patterns revealed in the questionnaire Table 4.16 shows the capacity available during different hours. A maximum of 40 MW per hour is available, but these are placed in weekends. In peak load periods (weekday, 9-19) the available capacity is much lower.

MW	*Weekday*	*Weekend*
6-9	8	9
9-16	8	**40**
16-19	**25**	**40**
19-23	**21**	**34**
23-6	2	4

Table 4.16 Capacity available during periods.

Finally, a word of caution. The pilot study is based on 600 questionnaires focusing on mean compensation levels. 8% is equal to about 50 respondents and this is scaled to 1,000,000 consumers with the three appliances. Compensation levels are very rough, especially focusing on agreements with low compensation levels, and the questionnaire has not been sufficiently elaborated on individual appliances and demographic questions, implying that estimates have very large confidence intervals.

Another consideration is, that the three appliances washing machine, dryer and dishwasher were chosen for the pilot study, as disconnecting these machines imply some discomfort for the consumers, and asking the consumers to reveal preferences between discomfort and compensation. Other appliances, e.g. electric heating, refrigerators and freezers may be disconnected for short time without consumers experiencing a discomfort. Targeting these appliances, consumers may accept disconnections requiring much lower levels of compensation.

4.5 Interval meters

In Denmark all electricity users with a yearly demand of more than 100.000 kWh have an interval meter. A little more than 50% of the total electricity demand is covered by the interval meters. The rest is typically read once a year and these customers share a common profile, which is defined as a residual (the total demand minus the demand measured by interval meters this is calculated per grid company). The calculated profile is used when the demand is divided to individual hours.

Because of the profiling system individual customers without interval meter have no incentive to adapt their electricity use to prices. Whether they use electricity in day time or at night, the price is the same. The reduced cost obtained by moving demand from a high price period to a low price period is distributed to all costumers without interval meter (within each utility area).

Table 4.17 illustrates what three different user groups would have to pay if they had interval meters and were charged hourly spot prices. The average payments vary from 24.6 to 30.8 øre/kWh. Without interval meter, they would all pay the same price (the profiling price, which it not calculated here, but would be close to the price for single family houses without electric heating, since this is the largest group without interval meters). Note that the variation in electricity price can be much larger for individual users.

Values for 2003	øre/kWh
Single family house, without electric heating	28.7
Single family house, with electric heating	30.8
Irrigation	24.6
All demand	28.7
Average spot price	27.3

Table 4.17 Spot price weighted by the profile for three selected user groups and for all demand. The electricity demands are taken for a sample with hourly values (Elforbrugspanelerne). Spot prices are for Eastern Denmark. Transport and taxes are not included.

Looking at households with electrical heating (assuming an annual consumption of 12,000 kWh) Table 4.18 illustrates three different tariffs and with and without adaptation to prices. When changing from the fixed tariff (A) to a spot price tariff (B) the household must pay additional DKK 0.030/kWh. However, if the demand can be adjusted to the price variations, the average price will increase DKK 0.002/kWh, only. Comparing a flexible and a non-flexible consumer with electric heating, a flexible consumer saves DKK 336 /year, which is a modest reduction (1.5%). Figure 4.7 shows a flexible consumer’s assumed linear reaction to price changes (if the price is reduced by 100%, consumption is increased by 50%, and if price is increased by 100%, consumption is decreased by 50%). The reference price is the DKK 1.80/kWh.

Tariff C is an extreme example where all elements in the tariff are varying proportional to the spot price. Assuming an unchanged total demand, in this case DKK 3,569 would be saved by adaptation of demand to prices (15% of costs). That is, by load shifting from high- to low-priced periods. The tariffs in column C are meant as an example – they are not for practical use.

	A Fixed price	B Energy as spot price	C All tariff as spot price	
All demand	1.80	1.80	1.80	DKK/kWh
Electric heating, no adjustments to price variations	1.80	1.83	1.93	DKK/kWh
Electric heating, adjustments to price variations	1.80	1.80	1.63	DKK/kWh
Value of adjustments	0	336	3,569	DKK/year

Table 4.18 Cost of electricity for a house with electric heating (12,000 kWh/year) in three scenarios: A. With a fixed price of DKK 1.80/kWh (tax included), B. where the energy is paid as spot price, and C. where for all cost element the payment is proportional with the spot price. In all cases the tariff is adjusted so the average cost for all demand (the sum of all sectors) is the same. For electric heating the cost are calculated with and without adaptation of the demand to prices.

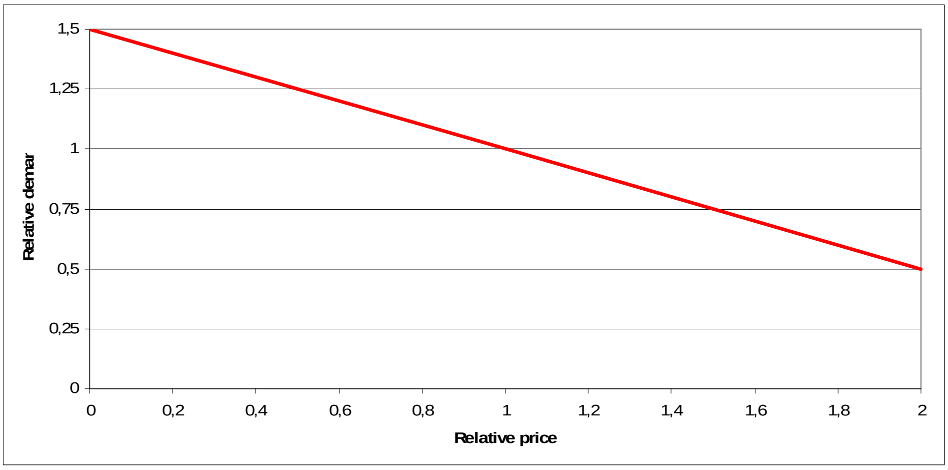


Figure 4.7 The assumed reaction to new prices.

Interval meters in Denmark

Six Danish distribution companies are currently working to implement interval meters. The new meters are able to collect data per hour, but are typically planed to be used with monthly readings. The number of meters corresponds to 13% of all meters in Denmark.

Syd Energi	250,000 by end of 2008
Odense Energi	31,000 by mid 2007
Energi Fyn	25,000 by mid 2007
NESA	20,000 by 2006
Hillerød and Roskilde	58,000 by 2011
Total	384,000 meters = 13% of all

Table 4.19 Current plans for interval meters in Denmark.

The benefits of interval meters are shared by many parties while the investment costs must by paid by the grid company. Some grid companies in Denmark and abroad have invested in interval meters, but if interval meters shall be used widely, regulation is needed (ESC, 2004).

According to the EU directive on Energy services all member states shall ensure that final customers are provided with individual meters that provide information on actual time of use. When an existing meter is replaced, such meters shall always be provided (if cost effective).

Experience from other countries

Several countries have required interval meters to be implemented in large scale (Ofgem, 2006), e.g.:

- In Canadian Ontario it has been decided that all 4 million customers shall have an interval meter by year 2010.
- In Italy, ENEL is concluding a five years project installing advanced meters to 30 million consumers at a cost of 70€/meter (all included). This technology uses power-line-communication to each meter and the costs are expected to be paid back after 4 years[6].
- Sweden has decided that by 2009 all consumers most have their meter read monthly. Hourly reading is not demanded, but practically all new meters are expected to be able to record hourly values.
- In the Australian province of Victoria most consumers must have interval meters by year 2013 (app. 1 million). For consumers with single phase installation (300.000) interval meter must be installed when renewing the meter.

Three recent reports analyse the cost and benefit of large scale use of interval meters. See Table 4.20. The different studies include different aspect in the cost-benefit analysis. E.g. the Dutch report does not consider reduced misuse of market power as a benefit. And the Australian report does not consider reduction of unpaid electricity.

All three reports find benefits to exceed costs, although many issues are difficult to value. For households with limited demand the benefits are moderate.

[6] Savings are influenced by the tariff system used in Italy. Many households use a tariff with a maximum 3.5 kW electricity demand. If demand exceeds this value, the supply is interrupted. If the household would change to a tariff with a higher rating, an operator should come to the meter and change the settings. With the new meter the operation can be done remotely.

Benefits	UK report Ofgem, 2006	Australian report ESC, 2004	Dutch report Dijkstra et al., 2005	Italian presentation Malaman, 2006
Economic signals. Reduced peak demand (DR) Increased market efficiency Efficient rationing	● 2.5%	●	●	●
Better competition Avoid misuse of market power	●	●		
Fairness (avoid profiling) Avoid cross subsidies No need for estimated data Less complaints to call centre	●	●	●	●
Instant meter reading when change of retailer	●	●	●	●
Energy savings from better feed back	● 1%	●	●	
Knowledge about network flow Faster reporting of fault Monitoring of quality of supply	●	●	●	●
Reduced use of unpaid electricity	● -25%		●	●
Reduced cost of meter reading	●		●	
Load limiters for emergency use	●			●
Product innovation New tariffs Social tariffs	●	●		●

Table 4.20 Benefits analysed in three analyses of interval meters. A dot indicates that this issue is included in the report.

Smart meters

When evaluating the cost of installing meters it is relevant to consider that meters may do more than record the electricity demand hourly and transport the values to the grid company. If they can, the cost of the meter should only partially be attributed to demand response. Addition features could be to transport price signals to the households or even signals for control of individual equipment. Or the meter could be equipped to disconnect users or set a limit for the electricity use. This could be relevant in relation to unpaid bills or emergencies. It has further been suggested that the new ENEL meters can be used for massive usage for interruptions recording and emergency load shedding.

An alternative to the use of meters as a gateway to the home is to use the Internet and a computer or a dedicated gateway. Hourly electricity consumption can be shown on an Internet homepage and signals for controlling demand can be sent by the Internet. New product for home automation with Internet connection is coming to the market these years. It can be practical to use the Internet, since the same equipment can be used in a large area. In Denmark more than 70 grid companies exist and many different advanced meters can be expected to be implemented.

4.6 Dynamic prices

Demand response is about consumers reacting to actual prices, e.g. delaying electricity consumption a few hours and in that way reducing the electricity bill. In this section the different components of the total electricity price will be analysed and discussed in relation to demand response.

Any type of averaging tariffs will decrease the incentive for a dynamic demand. The current tariffs for energy, transmission and distribution, ancillary service and taxes are averaging over both time and location. See examples of current tariffs in section 4.2.

The need for more dynamic tariffs is developing. Liberalisation of the electricity market combined with variation in the production (e.g. hydrological dry years/wet years and varying wind power) creates more price variation than seen 10 years ago. At the same time the possibilities for implementing dynamic tariffs are greatly increased due to the development of automated meter reading and the general ease of communication (Internet, broadband, home automation etc.).

While yearly meter reading was the only realistic option yesterday, hourly reading is realistic today, even for households.

Dynamic prices would be able to reflect the dynamic cost structure behind electricity production, transport, ancillary services, and even taxes. Dynamic tariffs would increase the motivation for demand response in the same way as future micro generation would be motivated to produce at the right time.

Optimal tariffs

Tariffs should send the correct economic signals to the users, but this is only one out of several requirements (Bjørndal et al., 2005). Design criteria for practical tariffs include:

- Reflecting marginal costs
- Recovery of total cost
- Ease of computation and transparency
- Fairness.

Ease of computation, transparency and fairness are not considered in the following.

When a user flips the electricity switch on, this is changing the costs of the system. Depending on the system condition these cost can be high or low. The marginal costs can be grouped as:

- Energy production. The spot price is defined as the marginal cost of production in that hour. To this could be added elements reflecting how the conditions has changed since the spot price was established.
- Transmission and distribution of electricity. This includes the impact of a marginal demand on the electricity losses (short-term marginal costs) and cost of expanding the network (long term marginal costs).
- Ancillary services costs. Including the marginal cost of the needed reserves.

- Taxes. E.g. environmental taxes could reflect the environmental impact of the marginal demand.

The marginal costs are heavily dependent on the time scale. In real-time or with hourly resolution large variation exist, e.g. in relation to losses. With daily, monthly or yearly resolution many variations are averaged out (Stoft, 2002, Vignolo and Sotkiewicz 2005).

Consider an energy production system with varying variable (marginal) production costs and some fixed costs. If the energy users pay a time varying price equal to the marginal cost, the energy consumption would be optimal. Rational users would only use energy if the benefit exceeded the costs. However use of marginal pricing does not necessarily cover the fixed cost (the revenue can be higher or – typical – lower that the total costs). Collection of the fixed costs can disturb the demand – away from the optimal allocation.

Three issues are important in the practical design of tariffs:

- How to deal with time varying costs? Often tariffs are designed constant for a long period, e.g. a year. A constant tariff for a year will average all costs variation in this period. As a result the tariff will be too high in some periods, and too low in others.
- How to cover fixed costs? If the fixed cost is collected as an entry fee, no disturbance is introduced (if all enter). However, practical problems can make this impossible, e.g. it can be difficult the design a fair entry fee for both small and larger energy users. Ramsey prices are a way to include a mark-up on the marginal prices in a way so the impact is minimal. In a general tax study all commodities can be analysed. However, for an electricity utility the scope is necessarily limited to electricity tariffs. If price elasticises are constant (i.e. independent of time and across user groups) a constant mark-up can be used (e.g. x% extra on the marginal prices). If price elasticises are varying, the highest mark-up should be used in situations with a low price elasticity. In this way the disturbance would be minimized (energy demand will be closest to the situation with marginal prices only).
- How to deal with differences in costs for different users? Different users, e.g. a centrally placed user compared to a more distant user. Typically tariffs are designed to level out differences, so all consumers in the same supply areas pay the same price. This levels out differences in delivery costs. Under the current Danish law it is only possible to differentiate according to geography in special cases.

Arguments for different forms of TSO/DSO tariffs

A simplified presentation of the different cost elements of the TSO/DSO is:

- Short-term variable costs: Losses. Typical 7% of the electricity consumption is lost in the transmission and distribution.
- Long term variable costs: Cost of expanding the network (lines and transformers). When demand is growing or when new production is installed investments in the network may be needed. In some cases this is paid by the users causing the need, but in other cases the utility must pay.

- Ancillary service. Reserves and voltage control.
- All other cost. Typical fixed cost, i.e. not directly related to the electricity consumption or electricity transport. This is by far the largest fraction of costs. It includes daily operation, administrative issues, including meter reading and billing. Also some public service obligation (PSO) activities like promoting energy efficiency and support for research.

Losses

Typical 7% of the electricity consumption is lost in the transmission (1%) and distribution (6%). 60% of losses occur in lines and 40% in transformers (CCTP, 2003). Losses are strongly dependent on the transport of electricity. A doubling of the transport increases the losses with a factor four. The actual transport of electricity is caused by a combination of production and demand. Because of import, export, and transit the losses can be high even when demand is low. High voltage direct current (HVDC) transmission lines are used to connect different electricity areas (e.g. between Nordel and UCTE). HVDC are efficient for long distance transport of electricity, but have an initial conversion loss of 1.2%.

In relation to losses, a real time tariff could ideally send a time varying signal. The losses in a line or transformer vary quadratic with the power flow. This means that the marginal loss is twice the average loss (Stoft, 2002). With local production the flow can change direction over time and the marginal loss due to a marginal demand can be positive or negative. When local production is higher than the local demand the marginal losses of additional demand will be negative. The marginal losses can be in the order of +/- 30% of the electricity delivered.

Due to the quadratic relationship with the power flow, a truly marginal pricing of losses will create too large revenue. Typically in the order of a factor two (Stoft, 2002, Vignolo and Sotkiewicz, 2005).

Nodal pricing (locational marginal pricing) can be used for losses in transmission and distribution systems. The marginal loss can be calculated for a marginal electricity transport from a reference node to each node (bus). The selection of reference node does not influence the result. The calculation could be done the day ahead based on the planned power flow in the network (Stoft, 2002).

Sotkiewicz and Vignolo (2005) illustrate that nodal pricing can be used for a distribution network also, and conclude that this will be an advantage for distributed generation. By timing the production right a higher price can be achieved. Exactly the same can be argued for demand, which has the potential for being adjusted to actual prices.

The costs of losses are calculated by multiplying the physical losses (kWh) with the price for electricity (DKK/kWh). Therefore e.g. nodal prices of losses will generally – but not always – increase the total price variation compared to the variation of the spot price alone.

The TSO buys the expected losses in the transmission system on the spot market based on a calculation of the expected flow in the grid. This means that the relevant information about the losses already exist today. This information could be used as a basis for a tariff for losses.

As mentioned above expansion of the network can be caused by demand or by generation. Investments can also be caused by the need for a more secure system or the need for more exchange with neighbouring areas. Several investments in transmission lines in the Nordic area are examples of the system arguments.

The electricity demand in Denmark has the last ten years shown moderate growth rates in the order of 1% p.a., so limited investment in expanding the grid is done. This situation may change, and dynamic tariffs may become important. As an example Australia can be mentioned. Australia has experienced a massive increase in the use of air conditioners, from a penetration of 35% in 1999 to 60% in 2005. This creates a considerable growth in the peak load and results in needed investment in transmission and distribution as well as production. Because a simple tariff is used, the investments are not only paid by those adding to the peak demand, but by all consumers. So, consumers invest in new air conditioners, without including the true cost of delivering electricity to these. A dynamic tariff with prices according to the need of local grid investment could address the cost to the relevant users.

Strbac et al. (2005) describes how elements in the distribution system (lines and transformers) can be demand dominated or generation dominated. Dependent on the actual demand and the location of generation (including combined heat and power and wind power) a line or a transformer can be close to its limit in two directions. In the case that no more demand can be tolerated the element is demand dominated and visa versa. A system with positive and negative tariff is developed. When the incentive is to limit demand (positive demand tariff) at a certain node in the system, the incentive at the same node is to increase generation (negative generation tariff).

Examples of innovative tariffs

In section 4.2 the French Tempo tariff and US GoodCent are described. These are examples of Critical Peak Prices (CPP), where a high price can be announced with short notice.

In Norway transmission and distribution tariffs with a rebate is offered if the utility is allowed to disconnect supply. The right can only be used in relation to grid problems. The system must not be used in relation to high spot prices. Table 4.21 shows the reduced tariff with different notice periods and duration (valid for the transmission grid, 2006, www.statnett.no).

Notice	Maximum duration	Reduction
15 min.	-	95%
2 hours	-	75%
15 min.	2 hours	25%

Table 4.21 Requirements for the reduced Norwegian grid tariffs.

This tariff is used for a limited number of end-users, typically energy intensive industries or electric heating with oil back up. The reduction is given on all electricity use, so this tariff does not increase the incentive to change demand in relation to prices.

With this design, the rebate are independent of the number of incidences it has been activated. It is like a fixed payment or a reservation payment. This can be interpreted as an unnecessary payment in years with no need for activation – and a cheep resource in years with extreme need for activation.

If the tariff was designed as a critical peak pricing, and this tariff was offered to all end-users (with interval meter), this could increase the incentive for demand response, and could deliver the reserves at a lower cost. The cost reduction comes from the fact that more end-users can deliver the reserves (transaction costs ignored).

A design that would make the payment fairer (in relation the varying need) could be a 2 levels CPP tariff, where the first part is the standard grid tariff and the second part is a high tariff, activated when needed, only. In years with no need the tariff would just be the standard tariff. This could be the default tariff to all end-users with interval meter. In this way more demand side resources would be exposed to the price signal, which could lead to a more effective reaction. The income from the high price could be used to reduce the net tariff in the same local area.

	Current rebate tariff	Alternative CPP tariff
Target group	Limited number	All
Over/under payment with varying needs	Yes	No
Varying reaction	Yes	Yes
Secure reaction	Yes (based on contracts)	Yes, but based on statistical knowledge from prior activations
Need for sanctions	Yes	No

Table 4.22 Comparison of the current and alternative tariff.

The three variations of the tariff with different combinations of notice and duration would not be needed in the alternative tariff. The high CPP value could be active as long as needed by the grid. End-users could react as they found best. If they could not reduce the demand, they must pay the high tariff. In this way end-users that could endure a three hours reduction could have the full benefit, as well as users that needed longer notice.

Kopsakangas-Savolainen (2004) analyses different types of tariffs for Finish grid utilities including marginal prices, Ramsey-prices and optimal two-part tariffs (with an initial payment). The current (1998) average tariff is 2.108 cent €/kWh. The computed marginal pricing is 1.192 cent €/kWh (57%). As a consequence of the marginal pricing the revenue is not maintained. In this case only 57% of the original revenue is collected. The costs included as variable are based on estimation done by the utilities. It must be noted that it is the long term marginal costs that are taken into account in this study. With Ramsey-prices and the optimal two-part tariffs the fixed cost are also covered. The optimal two-part tariff is calculated to: 149€ (fixed payment per customer) and 1.151 cent €/kWh. The article concludes that significant welfare benefits can be achieved by use of the alternative tariffs. Since marginal pricing will maintain the revenue optimal two-part tariff is recommended.

Discussion

Marginal losses in the electricity system associated with a (marginal) demand can vary significantly. The marginal losses can be negative (an additional demand close to local production can reduce the losses, since the alternative can be more transport) and can be very high, probably in the range of +/- 30% of the demand. Ideally the consumers' payment for losses should be both depended on time and location (marginal, nodal pricing). This would add more dynamic to the total price and the dynamic from the losses will be positively correlated with the spot prices (the losses in energy terms might be loosely correlated with the spot price, but the costs of the losses is equal to the spot prices).

Marginal, nodal pricing for the losses can be very advanced or simplified. A simplified tariff could be to collect the average losses (7% of energy demand) as spot prices. This would not signal the varying losses, but could be a first step. An alternative could be to use three levels e.g. be zero payment, the average payment (7% of demand) and a high payment (20% of demand) in form of a CPP tariff, where each level could be dispatched each day.

When investments in new cables and transformers are driven by demand (which is not always the case) tariffs could be used to send the signal of high long term marginal costs. One alternative to investments in cables is a reduced demand or local production. Often it is only in a few hours per year that the capacity of the network is too small. This fits well with the idea of demand response – to adjust the demand to seldom situation, where the benefit can be high.

As shown above the Danish TSO/DSO tariffs are TOU or flat. TSO/DSO tariff can be more advanced than TOU or a flat tariff. Different types of real time prices can reflect how the costs are generated. This can be relevant in relation to variable costs (e.g. losses) or better use of capital (reduced load on critical lines or transformers) if:

- Generation are able to react to prices, e.g. local CHPs
- Demand are able to react to the prices
- Costs of managing real time prices are low (meters, data handling).

The majority of TSO/DSO costs are fixed cost (Sotkiewicz, 2005). These can ideally be collected as Ramsey prices. If constant elasticises are assumed this means that the fixed costs should be collected as a mark-up on the marginal prices. Alternatively costs can be covered as a start fee (e.g. as a subscription fee).

The principle illustrated here would form cost efficient tariffs and would increase the incentive for demand response.

Taxes could also be used to promote demand response. However, this would more be in the form of a subsidy – and not at optimal pricing. A moderate time-variation of taxes could be a more efficient way to promote demand response, depending on the alternatives.

5 Quantitative analysis of demand response

Applying simulations of partial equilibrium models the aim of this chapter is to quantify values ascribed to the introduction of short-term demand response. Section 5.1 focuses on the Nordic market and evaluates costs in alternative scenarios introducing different demand response options in the Balmorel-model. Section 5.2 addresses market power mitigation simulating Supply Function Equilibrium competition in the Danish electricity system.

5.1 Valuation of demand response using a Monte Carlo analysis

Demand response may not be profitable in normal (average) situations in the power market, but considering weighted cases including more extreme situations may change the picture. Indeed, it is suspected that the value of demand response in an average situation will be relatively small, compared to the average over a more representative distribution of situations.

This section aims at demonstrating a framework for valuation of demand response that includes probabilistic considerations, in order to also include the value of demand response in more extreme situation.

The method is illustrated using the partial equilibrium model Balmorel, covering the Nordic power market, and combining it with at Monte Carlo framework. The basic approach is to examine changes in total costs in Monte Carlo scenarios with and without demand response activities. Furthermore, in order to set the demand response activities in perspective, one of the scenarios include additional peak production capacity acting as an alternative to demand response.

By this approach, 100 cases with equal probability of 1% have been analysed for different scenarios. The cases differ with respect to hydro power generation, wind power generation and electricity demand. The analyses have been carried out for a winter period in year 2010 (a period with a relatively tight power balance).

The analytical setup is the meta-modeling approach presented in Violette et al. (2006). This is a methodology of how to combine existing modeling tools with Monte Carlo analysis to valuate different DR products.

The Balmorel model is used (see description in Meibom et al. (2005)) with adaptations needed to model demand response products. The analysis covers Nordic region (Denmark, Finland, Norway and Sweden) in the year 2010. The model calculates hourly prices for the selected winter weeks.

The Balmorel model setup

The Balmorel model[7] is a partial equilibrium model covering the electricity and combined heat and power (CHP) sectors in the four Nordic countries Denmark, Finland,

[7] The model is public domain. More information can be found at www.balmorel.com. Several papers as well as the complete model can be found here.

Norway and Sweden (Ravn & al. 2001). The model is divided into 10 price areas; 4 in Norway, 2 in Denmark, 3 in Sweden and 1 in Finland. The model is linear, and assumes perfect competition. The model optimizes the solution over the specified period. Full information including full foresight is assumed, e.g. the electricity demand and the wind power generation are fully known.

Data in the applied model combines historical data (for electricity and heat demand, wind power production and others) with scenarios for the future development in heat and power demand and installed capacity.

In the present version the simulation is with time steps of one hour's duration.

Boundary conditions for hydro power with storage capacity is given in the form of total production from hydro power for each week and each region, based on input from a version of Balmorel that optimises the use of hydro power over a yearly horizon. Consequences for weekly hydro balances of the simulated stochastic outcomes (see later) are ignored.

The exchange between the countries modelled is determined endogenously, according to relative prices and transmission capacities. The exchange between the modelled Nordic countries and Germany/Poland is represented using a price interface calibrated with the use of the long-term version of Balmorel. It is assumed that the net exchange between the Continent and the Nordic countries is zero in a year with average hydro inflow. The exchange between Finland and Russia is specified with fixed values giving a yearly net import to Finland from Russia of 11 TWh.

Scenarios

Five scenarios have been designed which cover a base case scenario, three DR scenarios and an alternative scenario with additional generation capacity. The idea is to compare the impacts of implementing DR with those of doing nothing or establish generation capacity instead. For each scenario, based on the outcome of three random variables, 100 simulations are performed.

In order to evaluate the different alternatives (e.g. gas turbine versus demand response), a number of output parameters for the different alternatives have to be calculated. The following five scenarios are analysed:

1. Reference (no additional peak load technologies). When the market does not clear consumers are disconnected at a price at NOK 5,000/MWh[8]
2. Demand response in form of peak clipping. As reference, but with additional 1000 MW in Southern Norway at NOK 1,000/MWh (disconnecting)
3. Demand response in form of load shifting (NO). As reference, but with additional 1000 MW with 6 hours flat payback (return energy) in Southern Norway

[8] 1 NOK = 0.13 Euro (10.11.2005, Oanda.com).

4. Demand response in form of load shifting (DK). As reference, but with additional 1000 MW with 6 hours flat payback (return energy) in Western Denmark
5. Gas turbine. As reference, but with additional 1000 MW additional power capacity in form of a single cycle gas turbine in Southern Norway.

Reference scenario

Capacity and technology data for the units in the present power system are taken from the data set described in Elkraft (2003). These data have been supplemented with a few other units to secure the best possible correspondence with aggregated capacity data distributed on main technologies and fuel types published by Nordel (www.nordel.org). This is further described in Meibom et al. (2005).

The focus of the analyses is the year 2010. The development of installed capacity in the period 2005-2010 has been constructed. In the entire period, 1% per year of the installed capacity of thermal power plants except nuclear power plants is decommissioned. In the period 2005-2010 new capacity included is investments planned today that according to our judgment are likely to be realised.

The development in the yearly power consumption in the period 2004-2010 is based on (Nordel, 2002).

Caused by some new investments in the period 2005-2010, like the new nuclear power plant in Finland, year 2010 is not a year with a very tight capacity balance. The capacity (excluding wind power) is still higher than peak load demand in winter. At the same time, the balance is tighter than today, as decommissioning and increase in demand amounts to more than the new investments.

With respect to modelling of the demand response activity, in the reference scenario it is possible to disconnect large power consumers, at a price of NOK 5,000/MWh, i.e. the demand in the Nordic region can always be reduced in order to meet supply.

The modelling of the reference scenario in some ways illustrates a no welfare loss situation, as all quantities of disconnection result in the same voluntarily payment for all consumers (in average NOK 5,000/MWh), and the disconnection is made at the level for all consumers at NOK 5,000/MW, which corresponds to paying all consumers willingness to pay, i.e. all consumers are paid the same amount for a disconnection. This can be illustrated in Figure 5.1 with a marginal willingness to pay that equals the consumer price when demand exceeds supply ($q_{load} > q^{max}$). The marked area is the payment to the consumers corresponding to their welfare loss, as the consumers in the model do not have decreasing marginal willingness to pay with increasing supply.

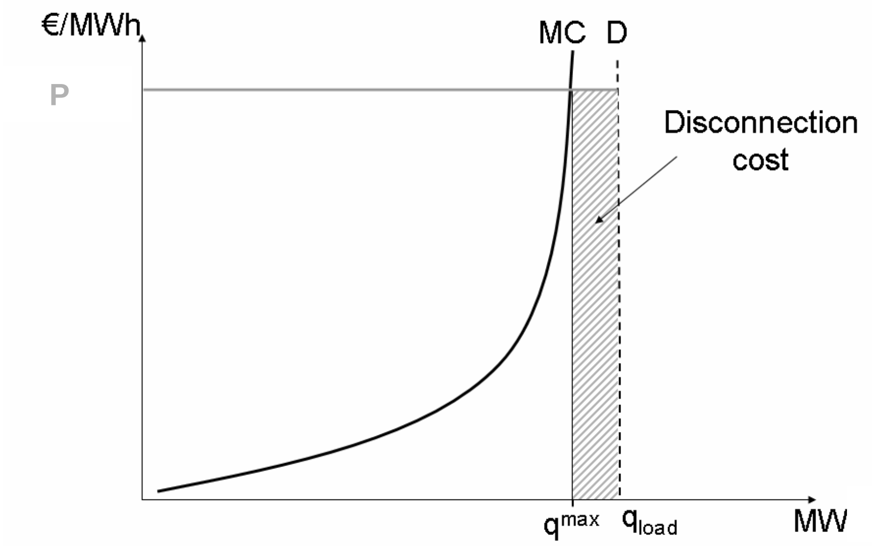


Figure 5.1 Illustration of costs in case of voluntary disconnection (DR) from q_{load} to q^{max} at NOK 5,000/MWh.

Demand response (peak clipping) scenario

In the peak clipping scenario, it is possible for consumers to decrease consumption in periods with peak prices. This is modelled by having 1000 MW capacity of demand response in Southern Norway at a price at NOK 1,000/MWh, i.e. total demand in the Nordic region can be reduced by 1,000 MWh in peak load periods. This demand response scenario illustrates the case, where there is a need to remove consumption and not just move it to other time periods.

Different from the reference scenario, the modelling of the demand response peak clipping scenario illustrates the case where the MWP curve in Figure 5.1 is not the real curve, i.e. there exists some consumers who have a lower marginal benefit from the power than NOK 5,000/MW. Consequently we gain welfare by activation of this resource. In this scenario the situation can be compared with the discussion surrounding Figure 5.2, where consumers with the lowest marginal willingness to pay are the ones to be disconnected. In this case the price is lowered from NOK 5,000/MWh to NOK 1,000 /MWh. This could, e.g. illustrate the DR activity where a group of consumers (1000 MW in total) gets a common contract at NOK 1,000/MWh. Thus, we obtain a welfare gain by introducing this agreement at NOK 1,000/MWh illustrated in Figure 5.2. That is, if the marginal willingness to pay in Figure 5.1 is not the correct one, there is a welfare loss in the reference case, which is gained by the introduction of the activities in the peak clipping scenario.

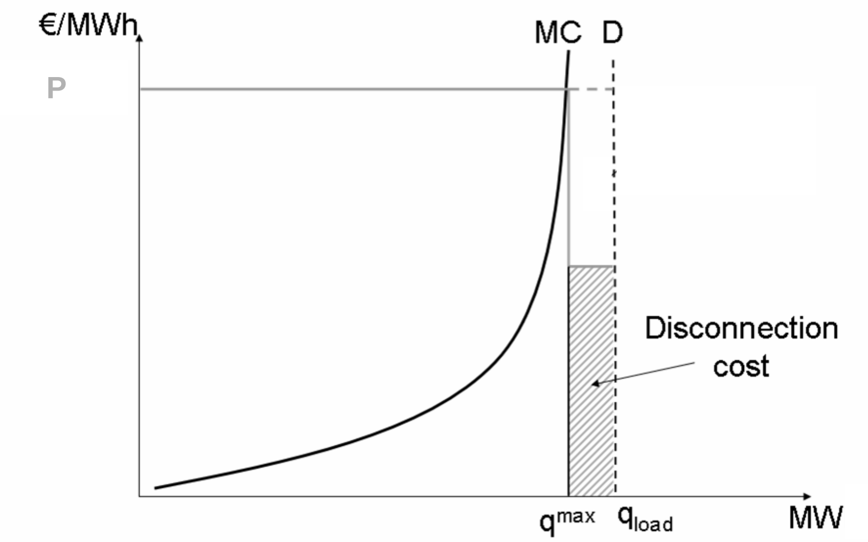


Figure 5.2 Illustration of Welfare loss and disconnection costs in case of voluntary disconnection (DR) from q_{load} to q^{*} at NOK 1,000/MWh.

Figure 5.3 Example, peak clipping scenario, high demand: Electricity prices in Southern Norway for in week 5.

Looking at the changes in prices, during week 5 in 2010 the introduction of peak clipping results in very few hours with effect if there are no hours with disconnection of demand in the reference scenario, i.e. prices at NOK 5,000/MWh. However, if there are high prices in the reference scenario, as illustrated in Figure 5.3 the situation is different. In this case, if 1000 MW is enough to clear demand and supply, the introduction of peak clipping at lower prices lowers the price level. When 1000 MW is not enough, the price stays at NOK 5,000/MWh.

Demand response (load shifting) scenario

In the load shifting scenario, it is possible for consumer to decrease consumption in periods with peak prices, but it is then necessary to pay back the energy during the following six hours. This is modelled by having 1000 MW capacity of demand response in Southern Norway or Western Denmark that function as an energy storage with no loss of energy and a basis profile illustrated in Figure 5.4 (left). With these parameters a maximum of 3,500 MWh electricity demand can be removed from the market within seven hours (sum of net flow in Figure 5.4 (right)). That is, we are effectively operating with a storage facility of 3,500 MWh that can deliver op to 1000 MW.

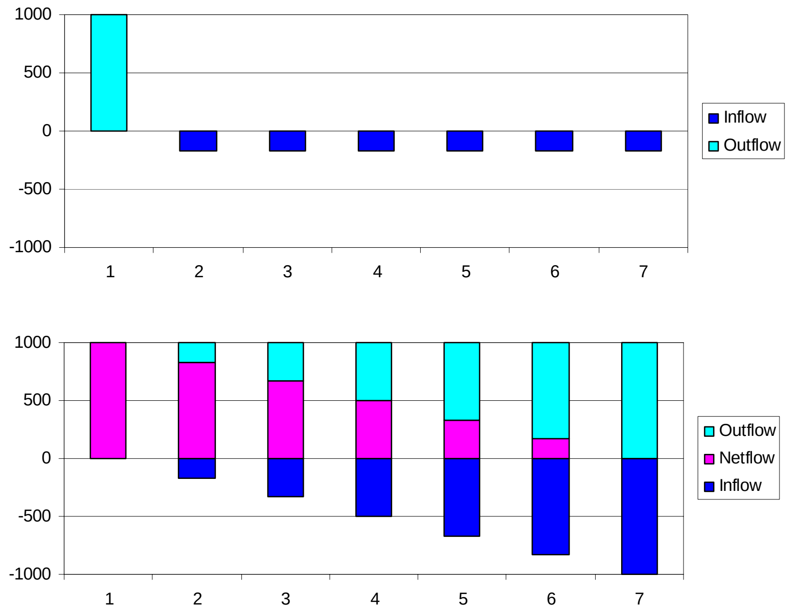


Figure 5.4 Profile for the demand response resource in the load shifting scenario with maximal use for one hour (left), and maximal use for seven hours.

This demand response capability is situated in Southern Norway in one scenario and in Western Denmark in another (scenario 3 and 4).

As illustrated in Figure 5.5, the introduction of such a demand response resource has relatively large price effects. The added resource is active in almost all hours of the week, lowering prices at daytime and increasing prices at night, i.e. equalising price during the week. This effect is partly caused by the fact that there are no costs or losses combined with the use of the storage.

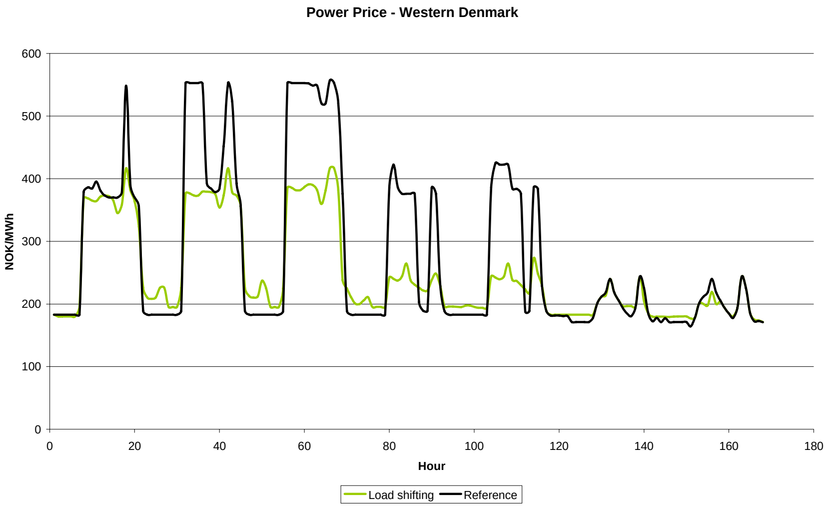


Figure 5.5   Example, load shifting scenario, high demand and low wind: Electricity prices in Western Denmark simulated for week 5.

To each of the 168 hours in week 5, there are corresponding amounts of capacity that are removed in each hour. See Figure 5.6.

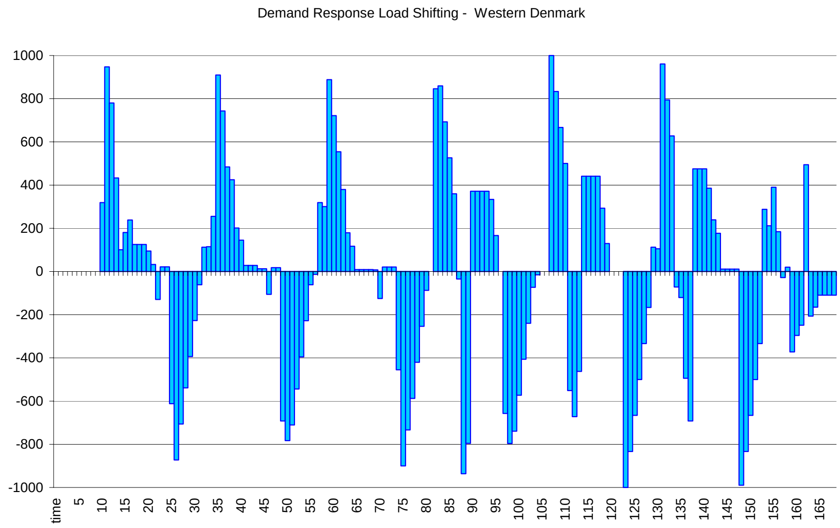


Figure 5.6   Example, load shifting scenario, high demand and low wind: Demand response capacities in use in Western Denmark simulated for week 5.

Gas turbine scenario

In the gas turbine scenario, a 1000 MW gas turbine is introduced in Southern Norway. This turbine produces electricity at marginal costs and is following able to reduce peak prices, by producing extra electricity instead of disconnecting consumers. The effect of introducing such an alternative is therefore very similar to the introduction of demand response peak clipping. The main difference is that the gas turbine produces energy to equalise demand and supply, whereas, peak clipping reduces demand.

Investment costs etc., are not included in the model runs. Calculation of the profitability of such a turbine will require a longer simulation period (at least a year) and is not included in the current analyses.

If existing capacity can already meet demand, the price effect of introducing a gas turbine is very limited, but in cases with disconnection in the reference scenario the gas turbine can avoid disconnections.

The Monte Carlo framework

It is suspected that the value of demand response in an average situation will be relatively small, compared to the average over a more representative distribution of situations. For this reason, a Monte Carlo framework has been designed and applied in combination with the above described Balmorel model.

By this approach, 100 cases with equal probability of 1% have been analysed for the above scenarios. The cases differ with respect to hydro power generation, wind power generation and electricity demand. The analyses have been carried out for a winter period in year 2010 (a period with a relatively tight power balance). Latin Hypercube sampling (Iman and Helton, 1991) is used as sampling method as embedded in the Crystal Ball programme.

The cases differ with respect to hydro power generation, wind power generation and electricity demand. The three parameters all focus on situations that can be corrected within a relatively long time horizon only. That is, they focus on energy problems in the system, and hence, not on sudden break downs caused by, e.g. sudden drop in transmission capacity.

Results

The purpose of the analysis is to estimate the value of demand response taking extreme situations into account. In order to do so, from the Balmorel model simulations information is gathered for electricity prices and total costs.

Electricity prices are gathered mainly in order to evaluate the price-impacts of the different scenarios. Also, prices indicate how strained the power system is.

In order to evaluate each of the alternatives to the reference scenario, total costs are the main focus of this study. The total costs are divided into production costs, costs of power exchange, and cost of disconnecting consumers.

The production costs include fuel costs, variable O&M costs and CO_2-emission costs. Fixed O&M costs as well as capital costs are not included as they only differ from one scenario to another with respect to the costs of implementing DR or establishing the gas turbine. Therefore, the estimated benefit in each alternative scenario should be compared to the expected additional costs. The CO_2-emission costs can be treated as a real cost as the Nordic countries have the opportunity to sell surplus quotas or the obligation to buy additional quotas depending on the amount of CO_2 emitted.

The costs of power exchange only vary from one simulation to another with respect to the power exchange with the Continent. The costs differ for two reasons; different prices and different amounts. In each simulation, the electricity price at the Continent is calibrated such that, in a normal hydro year, the annual net exchange is zero. However, the net exchange in the weeks analysed may very likely differ from zero. It is assumed that the prices in Russia do not differ between the simulations, and thereby there are no differences in system costs regarding the fixed 11 TWh annual import from Russia.

The costs of disconnecting consumers (decreased consumer benefit) are estimated as the amount disconnected in MWh multiplied by the consumers' willingness to pay in NOK/MWh. Therefore, in one simulation the production costs might be relatively low compared to another simulation due to additional disconnecting, but this should be counterbalanced by an increase in the disconnecting costs.

Transmission costs (losses) have not been taken into consideration.

Normally, costs are not sufficient to estimate the total welfare gain of introduction different scenarios, as alternative plans yields different power prices, hence, changing both demand and supply (Hobbs et al. (1993). But since the model assigns equal willingness to pay for all consumers the change between scenarios can be found by consideration of changes in production costs, transmission costs, and disconnections costs.

Most of the presentations in the sequel refer to one week (week 5) only, although eight weeks have been analysed, see further below.

Total costs over 100 Monte Carlo runs

Figure 5.7 shows the total costs in all 100 simulations and for all analysed scenarios. The cases are ordered after decreasing costs in the reference situation.

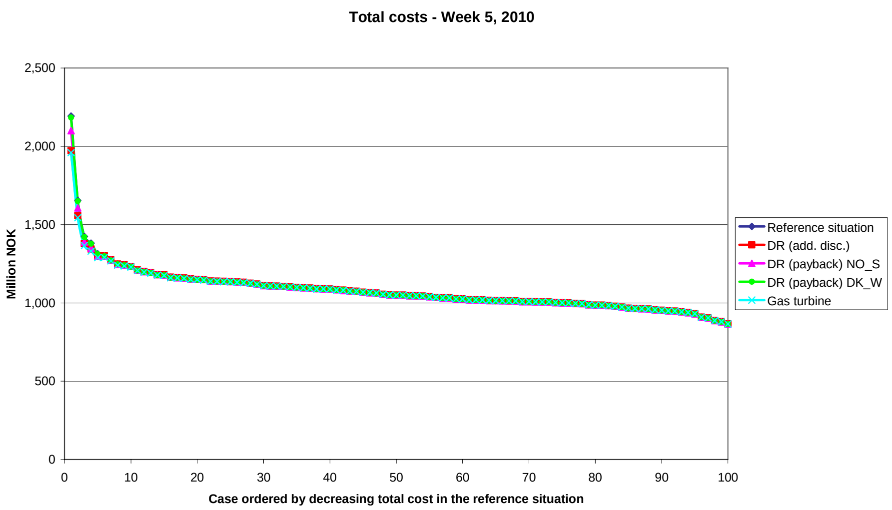


Figure 5.7 Total costs, all analysed cases. Notice, that the production cost of hydro power is not included in the figure.

The total costs vary from NOK 860 million in the cheapest case (low demand, high hydro and high wind) to NOK 2,190 million in the most expensive case. In many cases the costs do not differ much between the five scenarios analysed, but in some cases the saved costs compared to the reference situation is up to NOK 230 million.

As earlier mentioned, the total costs are divided into production costs, exchange costs and disconnecting costs. Between the scenarios, the production costs vary from NOK 835 million to 1,430 million, the exchange costs between NOK 30 million and 110 million, and the disconnecting costs between NOK 0 million and 706 million. The reason why the exchange costs are positive in all cases and scenarios analysed, is that week 5 comes up as a week with net import from the Continent.

The following three figures show the decreased costs within the three cost groups compared to the reference situation.

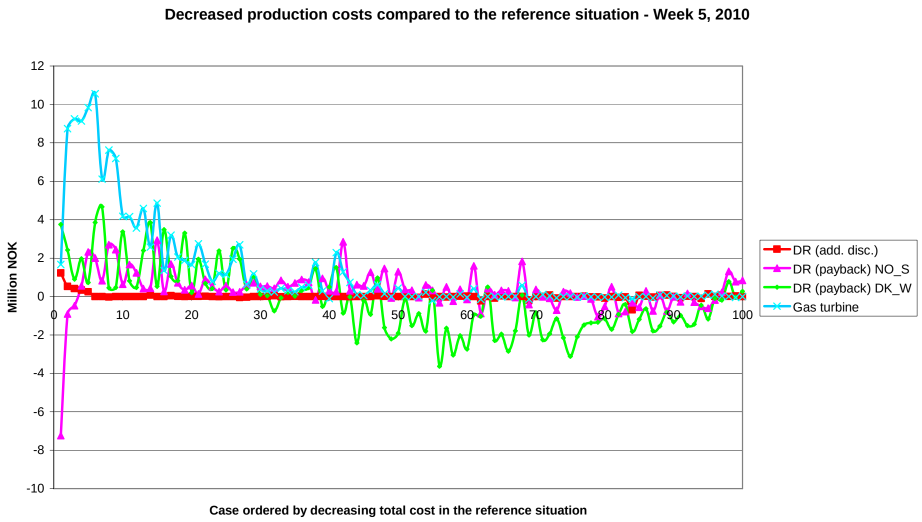


Figure 5.8 Decreased production costs compared to the reference situation.

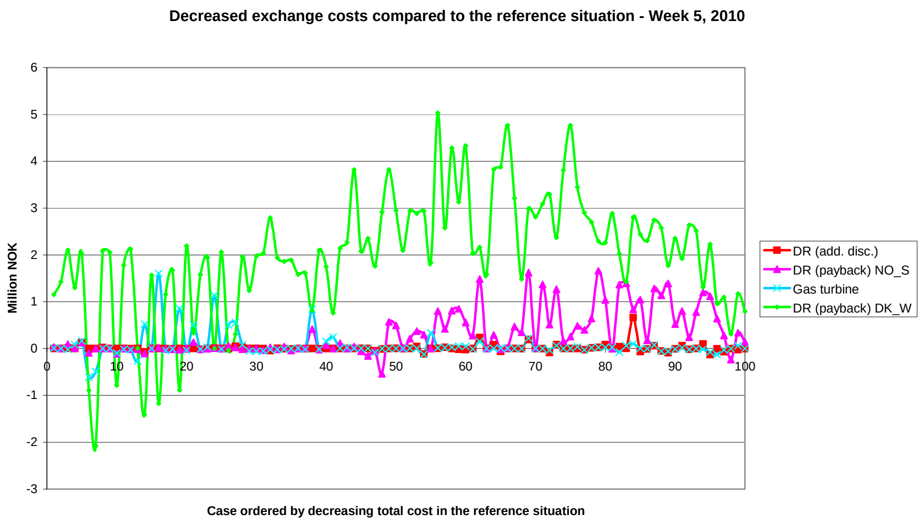


Figure 5.9 Decreased exchange costs compared to the reference situation.

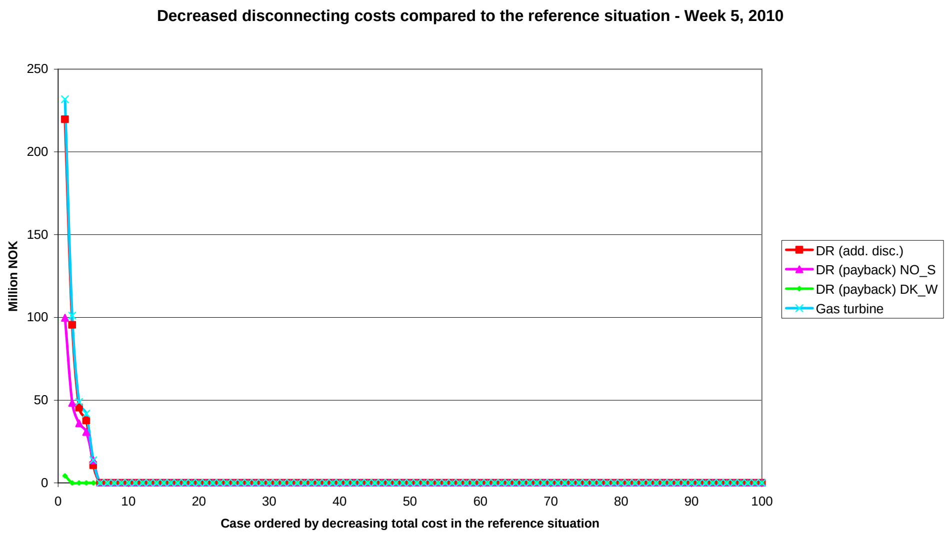


Figure 5.10 Decreased disconnecting costs compared to the reference situation.

The decrease in *production costs* compared to the reference situation is between -7 and NOK 10 million, the decrease in *exchange costs* is between NOK -2 and 5 million, and the decrease in *disconnecting costs* is between NOK 0 and 230 million.

Table 5.1 shows the total costs in the reference situation, and for the three alternative scenarios it shows the change in costs compared to the reference situation.

	10% percentile	50% percentile	90% percentile	95% percentile	Average
Reference	953	1,050	1,213	1,302	1,084
DR (peak clipping)	-0.0	-0.0	-0.0	-0.6	-4.1
DR (load shifting) NO	-0.3	-0.5	-1.9	-3.6	-2.9
DR (load shifting) DK	-1.0	-1.8	-2.6	-2.8	-1.8
Gas turbine	-0.0	-0.1	-4.4	-10.6	-5.7

Table 5.1 Total costs compared to the reference situation, million NOK.

It appears how, in particular for the DR peak clipping scenario, even the 95% percentile of NOK -0.6 million is much lower than the average of NOK -4.1 million. The reason for this is that the benefit is zero in most cases analysed but relatively high in some cases, therefore, the average of approximately NOK 4 million.

Furthermore, it appears that the benefit from the gas turbine is higher than the benefit from DR. The reason is that the variable generation costs of using the gas turbine are lower than the disconnection costs. The reason why the benefit from DR with load shifting is relatively low may be that it can be interpreted as a kind of additional electricity storage, with quite heavy restrictions, and that the value of such an additional storage in a system with lots of hydro power is limited.

Furthermore, comparing the benefits of the two disconnecting scenarios placed in respectively Denmark and Norway, we find that the flexibility in Western Denmark gains a lot from better use of the transmission line to Germany, counter wise, the case in Southern Norway where the benefit is mainly caused by decrease in disconnections.

The calculations shown in Table 5.1 were based on input data for week 5, and to the extent that the weeks differ with respect to input data such as weekly heat demand, electricity demand profile, concurrence between wind power generation profile and electricity demand profile, production capacity revisions etc., the results reflect this.

To get an impression of that, the calculations have been done for a total of eight weeks. The input data for the weeks reflect data as defined for weeks 1 through 8 in a historical year. Note that the simulations are performed for individual weeks, i.e. there is not assumed any chronological dependencies between them.

These calculations confirm that the bulk of the costs refer to a minor part of the Monte Carlo cases. Looking at the variations of the results between the eight weeks the results for week 5 shown in Table 5.1 are not extreme. The week with the highest average benefits shows benefits that are between 30 and 70% higher than the average values presented in Table 5.1. Furthermore for most of the weeks the benefits are smaller, and for some even zero. This confirms the skewness of the distribution that is observed in Figure 5.10.

The benefit in each alternative scenario should be compared to the costs of implementing DR and establishing the gas turbines. Assuming that the investment costs for gas turbines is around NOK 3 million/MW and assuming a (financial) lifetime of 20 years and an interest rate of 10%, the annual capital costs for 1,000 MW gas turbine capacity can be estimated to approx. NOK 300 million per year. If the average benefit of NOK 5.7 million in week 5 could be maintained for every week of the lifetime of the gas turbine, the gas turbine would precisely be economically feasible. However, since week 5 is a winter week, this is not likely.

The costs of implementing DR have not been estimated. In the peak clipping scenario, the average reduction in total cost in week 5 corresponds to NOK 4,100/MW/week, while the load shifting corresponds to NOK 2,900/MW/week in Southern Norway and NOK 1,800/MW/week in Western Denmark.

A typical reservation cost in 2005 for demand as reserves is between NOK 1,000 and 3,000/MW/week in Statnetts RKOM market. This market is only used in the winter period (November to April). With these figures load shifting might be competitive, if the energy payback is without loss, while peak clipping seams to be highly competitive.

For almost all cases the main benefit comes from the saved disconnection costs, except in the load shifting scenario in Denmark, which gains most from exchange costs. Therefore, the result is extremely sensitive with respect to the levels of the disconnections costs, which is set at NOK 5,000/MW and NOK 1,000/MW.

5.2 Imperfect competition and demand response

The present section investigates the role of flexible electricity demand for market power.

Market power in the Nordic electricity sector has been analysed by the Nordic competition authorities (2003). It was concluded, that the deregulation of the Nordic electricity sector has been largely successful, but also that some obstacles to competition remain:

- Bottlenecks in the grids divide the Nordic region into shifting constellations of relevant geographic markets.
- Market concentration in these geographic markets is very high.
- The high market concentration is partly due to cross-ownership and jointly owned production plants.
- Inflexibility of the production plants and capacity constraints on production enhances market power. Even a small firm can exert market power.
- Demand for electricity is very inelastic.
- Practises with negative effects on competition may have ripple effects all over the Nordic region.
- There are high barriers to entry.

Exercise of market power has the negative effect of reducing social welfare. Consequently, if increased flexibility of electricity demand can reduce the negative consequences of market power, this may be taken as an argument for promoting flexibility of electricity demand. Additional negative effects include a redistribution of wealth from consumers to producers, inefficient allocations of production, and misleading price signals for investments.

In the present section first an introduction to market power is given. Then the role of demand elasticity will be illustrated under idealised assumptions, permitting analytical solutions. Finally, the same analyses will be undertaken, but now applied to the Nordic spot market for electricity and solved with a numerical model.

Market clearing based on supply and demand functions

The following discussion will be performed with the Nord Pool spot market in mind. Briefly, this is characterized as a day-ahead market, where bids concerning the 24 hours of a day are to be given before noon the day before. Bids are specified with respect to time (the day and hour) but also with respect to the geographical location, in the form of bid areas that are interconnected by transmission lines of limited capacities. In other words, the daily market is separated into submarkets with respect to both time and space. This is in part an explanation for the existence of market power.

The market is cleared based on the received bids and available transmission capacities. This implies that prices are found for each bid area and accepted quantities are found for each actor in each hour such that all actors are satisfied in relations to their own bids. The solution in addition has the property that it maximizes the social economic surplus.

However, the last property holds true only if the bids are accurate reflections of the consumers' utilities and the producers' marginal costs. As is known, this is not true, and there may be discrepancies on both demand and supply sides.

As concerns the consumers' utilities this is treated under various perspectives elsewhere in this report. Suffice here to notice, that the utility of consuming electricity in an individual hour typically will be unclear or unknown even to the consumer himself. This may be because attention has not been devoted to that, since the traditional electricity bill is made on basis of consumption of electrical energy over longer periods, say three months. And even if the utility were know to the consumer, this may not be transmitted as a price signal to the market, again because the electricity price used for billing the costumer will be identical for all hours in the billing period (e.g. three months). Consequences in relation to this will be discussed later in this chapter.

Concerning the supply side, the received supply bids are not necessarily identical to the marginal cost. Some reasons for this are obvious. In particular, some production facilities have cost characteristics that depend on the number of hours of operation, and although there are bid forms (e.g. various forms of block bids) that to some extent can reflect this, complete correspondence can not be expected.

Clearly in a number of cases the discrepancies between the received bids and the marginal costs of production are so clear that no purely technical explanation is possible. In such cases it is obvious to look for explanations in terms of exercise of market power.

Market power concepts

Market power may be described and analyzed in terms of game theory. In game theory agents chose actions defined by their strategic variables. In an economic model of market behaviour this would either be the price of the product or the quantity that the firm produces. In general, the quality of the product could also be the subject of strategic considerations (for electricity this is probably more relevant to the retail market than to the whole sale market).

In the sequel only market power in relations to the supply side will be considered. When firms use a single price as the strategic variable, they must consider how the choice of price affects the quantity they are able to sell. This is called Bertrand competition. In a situation where firms do not have to respect any constraints on capacity the products of the firms on the market must be at least slightly differentiated in quality, function or brand in order to allow market power. Otherwise, the consumers would simply shift their demand to the rival charging the lowest price, with the result that the price would be as low as possible, i.e. equal to marginal production cost. The exception where the price need not become equal to marginal production cost is when production and/or transmission capacities are limited in relation to demand.

However, producers of electricity are restrained by the capacity of their production facilities. In this case, the firm charging the lowest price may not be able to serve the entire market, and it will thereby be possible for the firms to use their capacity constraint strategically in order to gain market power. The use of quantities as strategic variables is called Cournot competition. In this situation, the market power derives from the unwillingness of rivals to accommodate all the consumers that wish to shift away from a particular firm.

Although Cournot and Bertrand competition are traditionally the most commonly used means of modelling market behaviour, other options do exist. Some of these games utilize strategies which are much more complex than the simple price or quantity setting strategies. One such strategy is that a firm will supply a function or sequence of coordinates which specifies all the combinations of price and quantity at which it is willing to service the market. This strategy, called Supply Function Equilibria (SFE), is therefore conceptually a generalisation which contains the Cournot and Bertrand competition strategies as special cases.

Figure 5.11 illustrates the Bertrand, Cournot and Supply Function Equilibria. In Bertrand competition, firms set a price at which they are willing to supply all their capacity, i.e. a horizontal supply curve. In Cournot competition, firms choose the quantity they are willing to produce and the price is determined by the demand, i.e. a vertical supply curve. In Supply Function competition, firms indicate a functional form which specifies how much they are willing to produce at a specific price. The more they have to produce the higher is the price they charge per unit produced, i.e. an upward sloping supply curve.

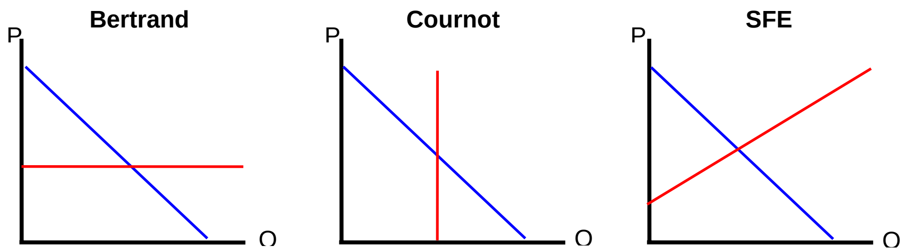


Figure 5.11 Bertrand, Cournot and Supply Function Equilibrium (SFE) competition.

If the pairs of price and quantity combinations at which a firm is willing to supply can be specified by a continuous function, e.g. a line or a polynomial, then the game is traditionally called a game in supply functions and the resulting equilibrium is called a Supply Function Equilibrium (SFE). On the other hand, if no function can summarize the sequence of coordinates, then the game is of the auction type. In the present context the term SFE will be used for either form.

As indicated in the figure, the Bertrand and Cournot equilibria are the extremes of the supply function equilibrium. Not surprisingly, the resulting market solution prices for the SFE competition will be between those of Cournot and Bertrand competition, with Cournot competition yielding the highest prices.

Game theory has several equilibrium concepts that apply to games of varying complexity (i.e. static/dynamic or complete/incomplete information). However, all these concepts are applications of the same basic idea. In order for agents to be in equilibrium, no agent must be able to choose a strategy that would make him better off, provided that all the other players stuck to their strategies already chosen. Most often this is called Nash equilibrium. Depending on the exact specification of payoff functions and strategy spaces as well as the equilibrium concept used, there may be either no, a unique or multiple equilibria. Mixed strategies (where the agents choose randomly among a subset of possible actions) may often alleviate a situation with no or multiple equilibria. A key analytical result is that under lenient assumptions a Nash equilibrium will exist either in mixed or pure strategies.

The following concentrates on the Cournot and SFE competition forms with Nash equilibrium solution. The Bertrand competition form is considered less interesting in this context because often the results will be equal or close to those of perfect competition (in fact, in case of unlimited capacity of all firms and any transmission capacities the result of Bertrand competition will be identical to that of perfect competition).

Illustration of Cournot competition

Now the results of applying Cournot competition to a small example will be illustrated. It is assumed that there is only one bid area and one hour. Demand is assumed linear, and a range of slopes are applied. To each slope the corresponding intercept with the price axis is chosen such that the demand function passes through the point with quantity 100 MW and price DKK 200/MWh. Five slopes are chosen, such that the demand elasticities at the mentioned point are -0.01, -0.05, -0.1, 0.2 and -0.5, respectively. See Figure 5.12.

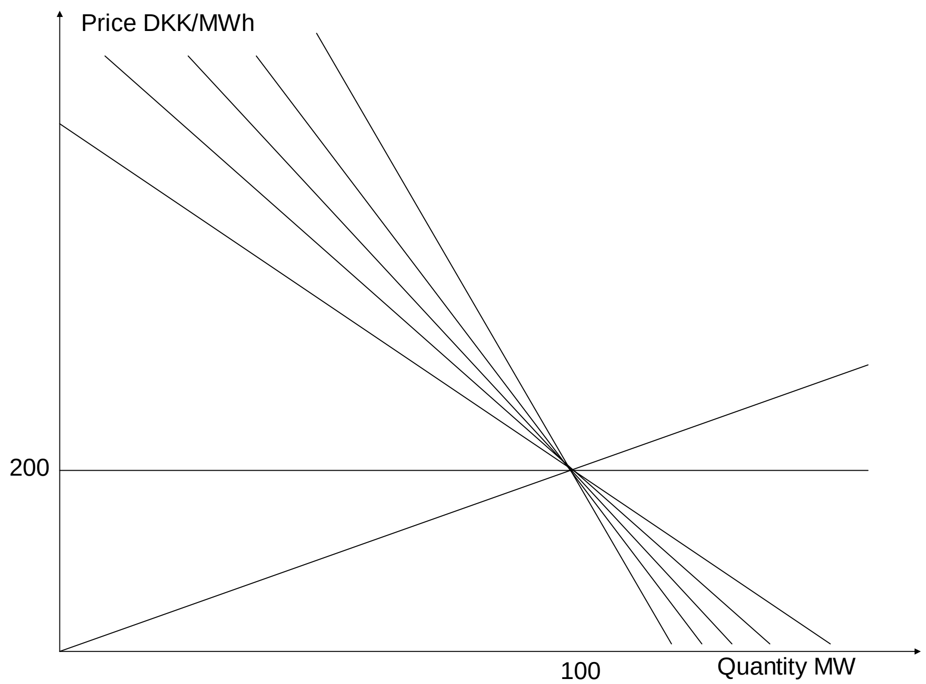


Figure 5.12 Illustration of market clearing with linear demand and supply curves. One supply and five demand curves are shown; the demand curves are alternatives. Irrespective of the demand curve, the market clears at 100 MW and DKK 200/MWh.

The supply side is represented by a number (between one and six) of identical firms. Their marginal cost functions are assumed linear, with a zero intercept with the price axis. Additionally their cost functions are chosen such that in perfect competition the market will clear at quantity 100 MW and price DKK 200/MWh. Their capacities are assumed unlimited (i.e. in this case at least 100 MW for each firm).

Figure 5.13 shows the result of solving this model for all combinations of the elasticities and number of firms in the case of Cournot competition. Note that the 'inf' indicates perfect competition (which is attained as the limit case for the number of firms increasing towards infinity).

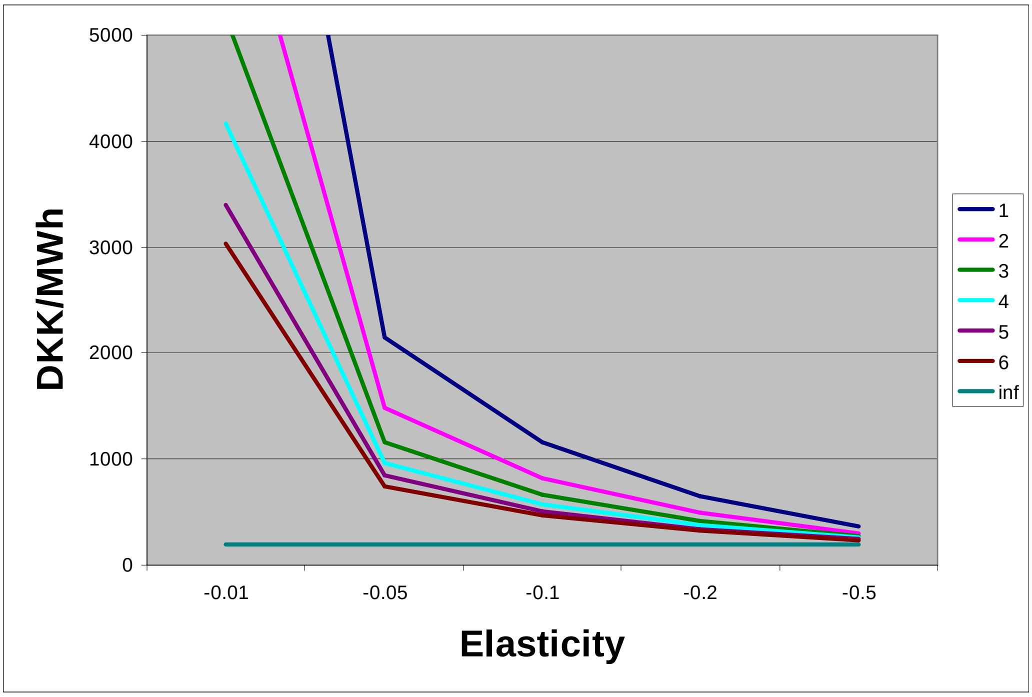


Figure 5.13 Price as function of number of firms and the demand elasticity in Cournot competition.

From the figure it is observed that as the number of firms increases the electricity price decreases. But the interesting observation in the present context is the high rate with which the electricity price increases as the elasticity decreases. Indeed, with six firms (which in a Nordic context is not a small number) an elasticity of -0.05 will permit prices that are almost four times those of perfect competition; and even an elasticity of -0.2 will permit prices that are more than 50% above the perfect competition price. Similarly it is observed that the reduction in electricity price that may be obtained by doubling the number of firms may also be attained by doubling the elasticity of demand.

It deserves mentioning that if demand is assumed completely inelasticity the Cournot model breaks down in the sense that no solution (with finite prices) exists; if a maximum price is declared on the spot market, the prices will reach that price.

Illustration of SFE competition

The Cournot competition model may be seen as unrealistic not only because it depends so heavily on the demand elasticity but also because the bid form implied (only a certain volume is bid into the market) will often appear unrealistic; the consequence that the market always clears at exactly the total supply volume bid into the market is likely to raise scepticism. The SFE model suggests an alternative that is more realistic in the sense that the supply curve that a firm bids into the market may encompass the firm's total capacity and more intuitively resemble a marginal cost curve.

In the SFE model it is assumed that the supply function bid into the market is the sum of the marginal cost and a mark-up. For now the mark-up is assumed to be a linear function of the volume, just like the marginal cost in the present example. Other forms are possible, for further information see the report Modelling Imperfect Competition in the Nordic Electricity Market with Balmorel (2005).

Figure 5.14 shows the result of solving this model. All data are the same as in the Cournot case reported above. As before 'inf' indicates perfect competition.

Comparing with the similar figure for Cournot competition, Figure 5.13, the prices here are seen to be much lower. Even with the low elasticity of -0.01 the price is below DKK 400/MWh if there are three firms. And if the elasticity is -0.5 the price is always below DKK 400/MWh, even with monopoly. In contrast to the case of Cournot competition it is possible to get finite prices also in the case of inelastic demand if there are two or more firms, this is also indicated in the figure.

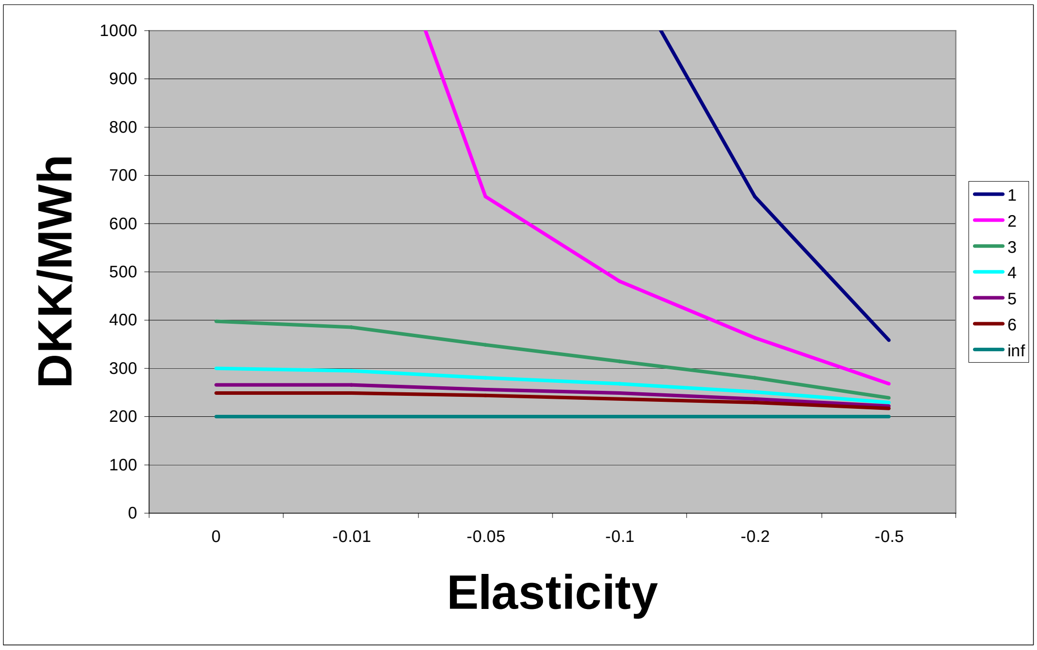


Figure 5.14   Price as function of number of firms and the demand elasticity in SFE competition.

Interpretation in relation to residual demand

To better understand the reason for the dramatic differences in results for the Cournot and SFE competition forms it is instructive to view this in relation to the residual demand. This also permits an interpretation in relation to the demand elasticity.

The residual demand to firm *i* is the demand that the firm experiences. This results as the combined consequences of the demand curve and the supply curves of the remaining N-1 firms.

In the Cournot model, firm *i* will experience a residual demand which corresponds to the demand function, except that the quantity is reduced by the sum of all the bids from the N-1 other firms. Or graphically, the firm experiences a residual demand curve that is identical to the original demand curve, shifted vertically to the left by the sum of all the bids from the N-1 other firms. See Figure 5.15. In particular this means that the slopes of the demand and the residual demand curve for any price are identical.

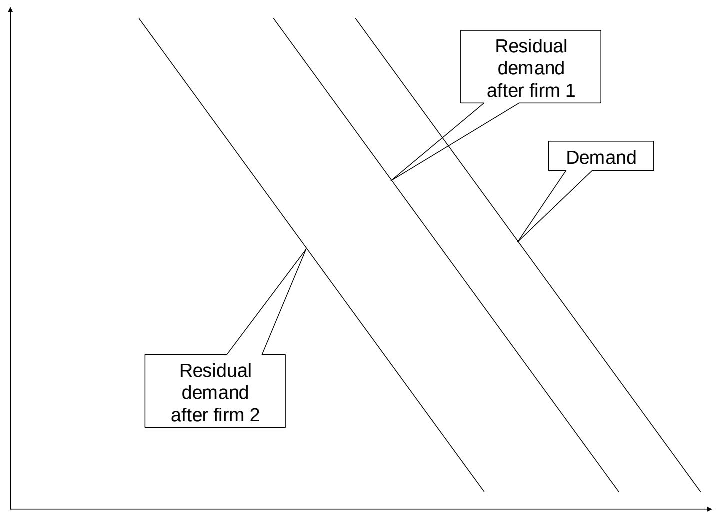


Figure 5.15 The residual demand function under Cournot competition with assumptions of a linear demand and supply functions and linear mark-up. The slope is independent of the number of firms.

In relation to SFE competition the situation is different. Here the residual demand experienced by firm *i* will have a slope that combines the slope of demand and the slopes of all the other firms' supply functions. Since all slopes are finite (in contrast to the Cournot case) such combination will invariably result in a slope that is more flat than the slope of the demand function. See Figure 5.16. This holds for all firms, and it follows that the resulting price will be lower than in case of Cournot competition.

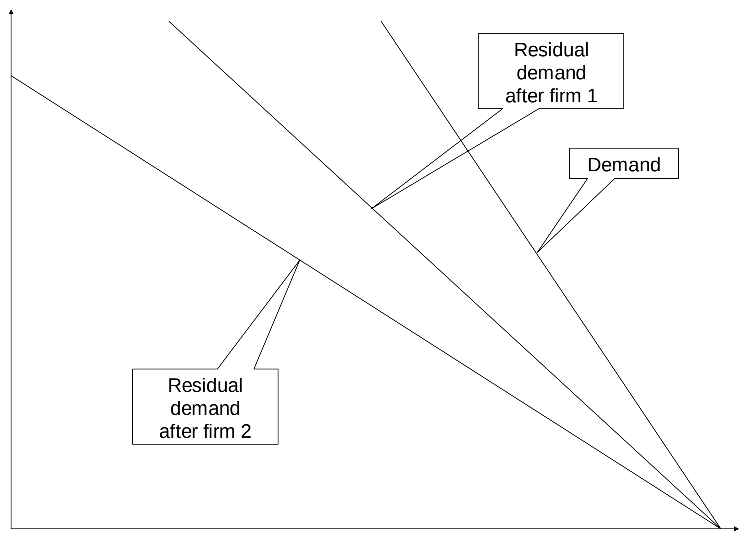


Figure 5.16 The residual demand function under SFE competition with assumptions of a linear demand and supply functions, linear mark-up and unlimited production capacities. The slope is more flat if the number of firms is increased.

Relating this reasoning to Figure 5.15 it follows that seen from the perspective of firm *i* the supply curves of the other firms has the effect that the residual demand for the SFE competition is more elastic than in the case of Cournot competition. Or, in other words: in the SFE competition the supply functions of the firms have the same effect as consumers' price elasticity. And the more firms present in the market, and the more flat their supply curves, the more elastic will the residual demand curve be. In turn, the lower will be the electricity prices.

Welfare loss

In case of imperfect competition there is a welfare loss, this is illustrated in Figure 5.17.

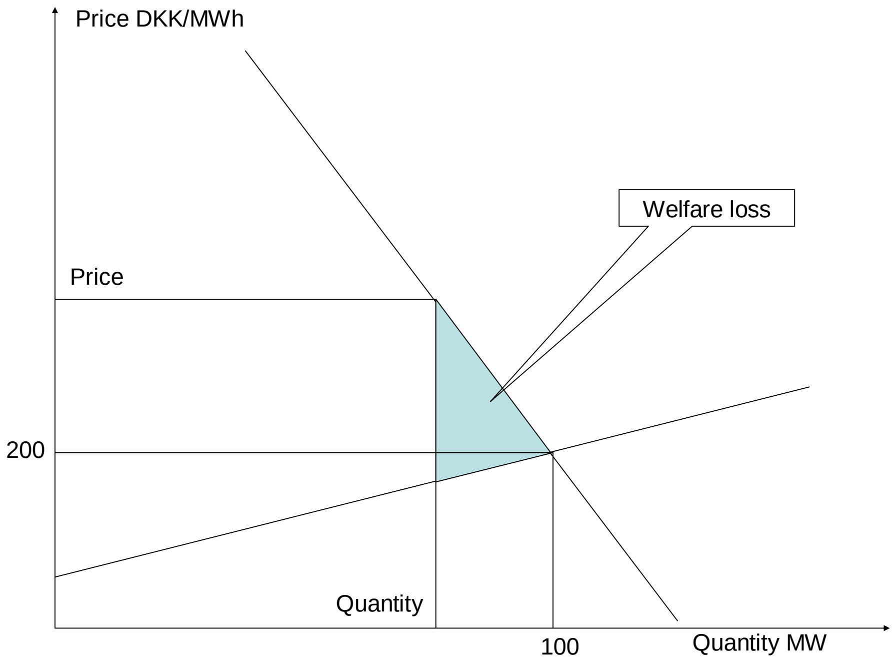


Figure 5.17 Welfare loss due to imperfect competition. The illustration may be compared to Figure 5.12. The welfare loss is indicated by the shaded triangle.

Figure 5.18 and Figure 5.19 show the welfare loss for the above cases, assuming a one hour duration. For the Cournot case in Figure 5.18 it is seen that the dependence on the number of firms is comparable in magnitude to the dependence on the demand elasticity.

As previously it should be pointed out that if demand is assumed completely inelasticity the Cournot model breaks down except when if a maximum price is declared on the spot market, in which case the price will reach that price. If this is the situation, the welfare loss corresponding to the completely inelastic demand case will be zero.

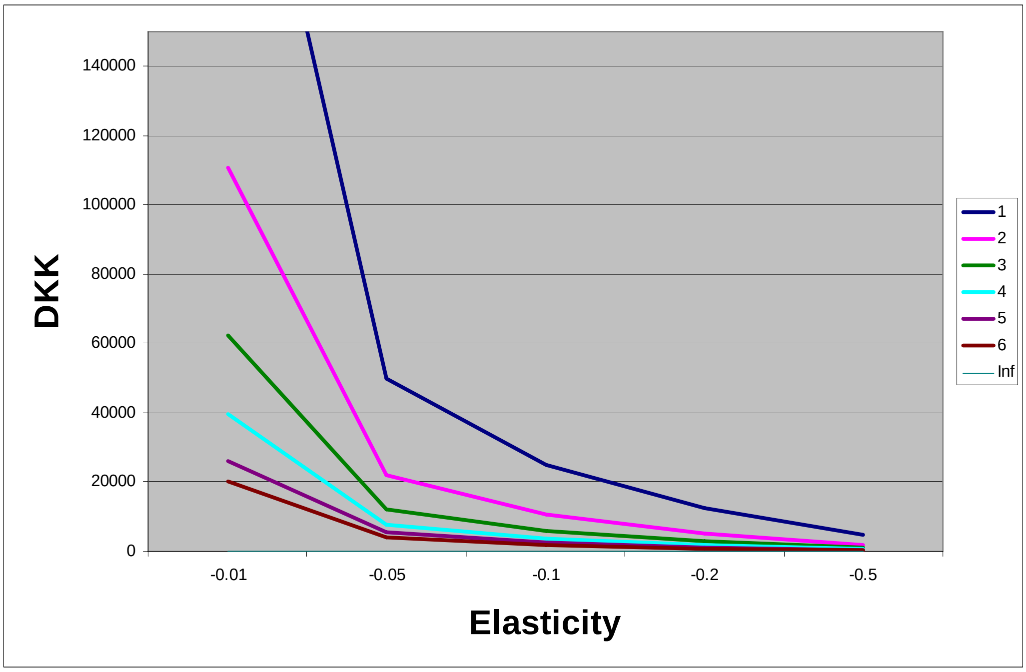


Figure 5.18 Welfare loss as a function of demand elasticity and the number of firms, Cournot competition. If the elasticity is zero and a price is obtained in the market, the loss will be zero.

For the SFE case in Figure 5.19 it is seen that the dependence on the number of firms is decisive, comparing the result for 1, 2 and 3 firms. Comparing to the case of Cournot competition it is seen that the magnitudes of the losses are much smaller.

However, the striking properties of in Figure 5.19 are the non-monotony of the curves and the fact that they attain the lowest values (zero, actually) at zero elasticity.

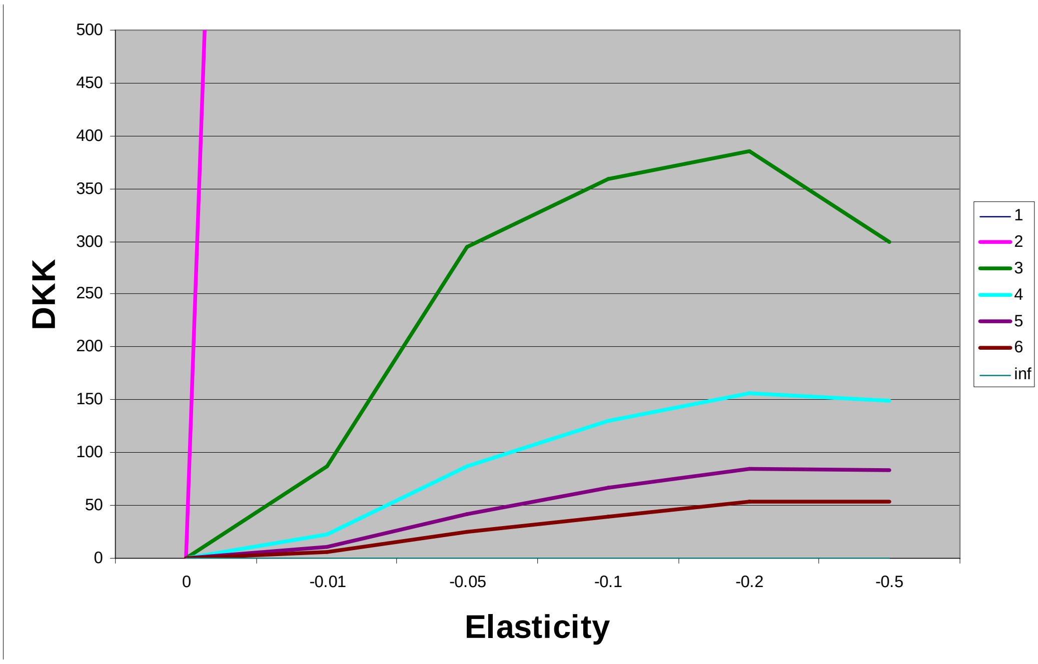


Figure 5.19 Welfare loss as a function of demand elasticity and the number of firms, SFE competition. Note that for 1 and 2 firms the curves are virtually vertical and identical.

The fact that the welfare loss is zero at zero elasticity is a theoretical result as well. This is easily confirmed by a look at the illustration in Figure 5.17, where the triangle representing the loss in case of zero elasticity will degenerate to have zero area.

Compared to a case where the elasticity is zero, there is therefore always with imperfect competition a welfare loss if elasticity is different from zero.

However, it is difficult to give any simple characteristics of the way the welfare loss will change with elasticity. The explanation for this may be found by considering Figure 5.17. The welfare loss is given as the area of the shaded triangle, and the dimensions of this triangle are non-linear functions of the other parameter values defining the problem. As already noted, if there is no demand elasticity (the demand 'curve' is vertical) there will be no social welfare loss associated with market power (but there will be a redistribution of wealth from consumers to producers). As demand elasticity is increased (the demand curve slopes more) the area may grow large since such increase permits a horizontal extension of the triangle. On the other hand, increasing the slope will also tend to reduce prices (see Figure 5.13 and Figure 5.14) and this may reduce the area in size. As the numerical illustrations show, the combined effect is that the welfare loss is not a monotone function of the demand elasticity.

Figure 5.19 shows that if the numerical value of the elasticity increases from zero, the associated welfare loss will increase, to attain a maximum and then, for further increasing elasticity, it will decrease. The elasticity at which the welfare loss is maximal depends on the number of firms. If the number of firms is between three and six, the maximum is attained at elasticities between -0.2 and -0.5, as seen in Figure 5.19. For two firms the maximum is attained around -0.00001, and the welfare loss at that point is around DKK 5,000 (not shown in Figure 5.19).

Now consider the implication of the above calculations in terms of welfare loss for the Danish electricity system. Assume that in the Danish system one year may be represented by 8760 identical hours, with an annual consumption of 33TWh, and hence an hourly consumption of (33TWh/8760) or approximately 3700MWh. Further assume that the marginal production costs are assumed linear and that the demand functions are linear, and that the perfect competition solution implies an electricity price of DKK 200/MWh and a quantity equal to 3,700 MWh. Then the annual loss due to exercise of market power may be calculated from the figures behind the above graphs in Figure 5.18 and Figure 5.19 by multiplication with approximately (8,760*3,700/100) or 330,000. Or, to get results in million DKK, multiplication by 0.33.

Referring to calculations behind Figure 5.19 shown in Table 5.2 it is then seen that the annual welfare loss in Denmark under further assumptions of SFE competition among two firms and demand elasticity of -0.1 is DKK 720 million. Increasing elasticity to -0.2 would decrease the welfare loss to DKK 521 million or by approximately DKK 270 million in the case of 2 firms. On the other hand, introduction of one more firm would decrease the welfare loss by approximately DKK 600 million to DKK 119 million.

	Elasticity						
No. firms	0	-0.00001	-0.01	-0.05	-0.1	-0.2	-0.5
1	-	-	82,476	16,426	8,232	4,097	1,578
2	0	1,625	1,249	900	720	521	294
3	0	-	29	97	119	127	99
4	0	-	8	29	43	52	49
5	0	-	4	14	22	28	28
6	0	-	2	8	13	18	18
Inf	0	0	0	0	0	0	0

Table 5.2 Welfare loss relative to perfect competition (number of firms equal to inf) as a function of number of firms and demand elasticity, SFE competition. Million DKK. A "-" indicates that the number has not been calculated.

While the welfare loss decreases with increasing demand elasticity in the shown range for 1 and 2 firms, this is not the case for 3 or more firms. Thus for instance for three firms the welfare loss increases from DKK 29 to 97 million when the elasticity is increased from -0.01 to -0.05. For two firms the maximal loss is roughly DKK 5,000, attained at an elasticity of -0.00001. As previously mentioned, for any number of firms there is a welfare loss of having any elasticity in demand, compared to having completely inelastic demand.

As previously mentioned the SFE competition may be seen as a generalisation that encompasses Cournot and Bertrand competition. The numerical results generated from the SFE and shown in, e.g. Table 5.2 should therefore also be seen as just one possible outcome in a continuous range from the least competitive Cournot to the most competitive Bertrand competition.

Inefficiency in production

The above examples were characterized by a number of identical firms exercising market power. The assumption of the firms being identical is of course unrealistic, but has the advantage of making the illustrations more convenient and transparent.

More realistically it may be assumed that there are a small number of price maker firms acting as profit maximisers, and a larger number of smaller firms acting as price takers. For a small firm it is actually rational to be price takers, because if it tried to increase the price (by bidding a smaller volume into the market (Cournot competition) or by increasing the bid price (SFE competition)) it would loose relatively much volume and increase the price relatively little with a reduced profit as consequence.

One important consequence when introducing small firms is that the distribution of production among the different units in the market may become inefficient, because the increase in price may make it profitable for small, less efficient firms to produce. This is unlike the previously analyzed situation where the assumption of identical firms will imply that the cheapest production is always applied first. In that case any welfare loss originates in the interplay between production and consumption, as shown.

The situation with price takers may be analyzed by extending the previous results as follows. Let the supply functions (marginal cost curves) of all price taker firms be aggregated to one supply function. Now consider the residual demand function, illustrated in Figure 5.15 and Figure 5.16, and assume that what is there indicated as “firm 1” actually represents the aggregated supply function for all price takers. Thus, the “residual demand after firm 1” in Figure 5.16 is actually the residual demand function that the price maker firms face as a whole.

The market situation may be illustrated as in Figure 5.17 where now the demand function corresponds to the “residual demand after firm 1” on Figure 5.16. For calculation of welfare loss it does not make any difference whether the demand function represents demand only, or whether it is a residual demand function including elements of price taker supply. The welfare loss illustrated in Figure 5.17 will then also in this case be the welfare loss associated with the situation with price taker firms.

If demand elasticity is increased this will have the effect that the slope of the residual demand function after firm 1 in Figure 5.16 and the slope of the (now: residual) demand function in Figure 5.17 will decrease (elasticity will increase). The consequence for welfare loss may be derived from Figure 5.18 and Figure 5.19.

For illustration, assume that the elasticity of demand is changed from 0 (completely inelastic) to -0.15. Assume that the competition form is SFE, and that there are 3 large price maker firms, and assume that the presence of price taker firms makes the residual demand function have an elasticity of -0.05. Other assumptions are as previously taken.

With a demand elasticity of 0, the residual demand has an elasticity of -0.05, and the welfare loss is from Figure 5.19 seen to be approximately 300 DKK. With a demand elasticity of -0.15, the residual demand has an elasticity of (approximately) -0.2, and the welfare loss is from Figure 5.19 seen to be approximately 380 DKK.

The example illustrates the method for calculating the change in welfare loss: the previous graphs may be used, but they should not be read off at abscissa points corresponding to the demand elasticity but at the abscissa points corresponding to the residual demand elasticity.

For Cournot competition the consequence is clear, because the welfare loss is a monotone decreasing function of elasticity, cf. Figure 5.18. Thus, the decrease of welfare loss associated with increasing demand elasticity is reduced.

For SFE competition the consequence remains almost as undecided as before. One firm conclusion is, though, that if demand is changed from being completely inelastic, and if residual demand is not completely inelastic, there need not be an increase in welfare loss, since the starting point will not be a zero loss. In all other cases comparison of welfare losses will be based on reading off curves that are not monotone, cf. Figure 5.19, and where it is not possible to give any analytical result concerning the direction of change.

Reconsidering the demand function

In the above analyses variation in the elasticity of electricity demand was a central analytical item. It is possible to observe two distinct uses of the electricity demand function in this. One use is as being co-determining (together with the supply side) the electricity price as a result of the market clearing. The other is as being used (again together with the supply side) as the measure of welfare loss.

Indeed, the two electricity demand functions need not be identical. In other chapters of this report it has e.g. been described how traditionally the electricity billing is based on a situation with identical consumer prices for all hours during long periods, e.g., three months. Thus, even in case a consumer might be willing to express some flexibility of electricity demand relative to the price, he does not do necessarily do so.

In the sequel the two demand functions will be labelled the "potential" and the "expressed" demand function, respectively. Thus, in this terminology, the above analyses assumed that the potential and the expressed demand functions were identical.

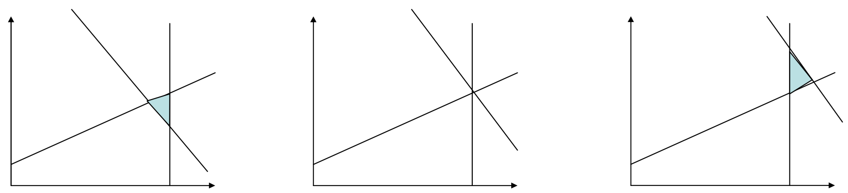


Figure 5.20 Illustration of the welfare loss in case of a difference between the expressed demand function (illustrate as a horizontal line) and the potential demand function (with a slope).

The concepts are illustrated on Figure 5.20. Each of the three subfigures illustrates a supply function and two demand functions. One demand function (the expressed one) is vertical while the other (the potential one) has a slope and hence some price elasticity.

The consequence in terms of welfare loss of having a difference between the expressed and the potential functions is illustrated by the shaded triangles. As seen, in general there is a loss, the exception is when the expressed and the potential demand functions meet in the market clearing point (middle subfigure). In the illustration to the left the consumption is higher than what is warranted by the potential demand function, while in the illustration to the right it is lower.

Thus, an immediate conclusion is that there is, save for the exceptional case, a welfare loss if the consumers can not (or at least do not) express their potential demand functions in the market. This observation has also been elaborated elsewhere in this report.

This conclusion was derived under assumptions of no exercise of market power.

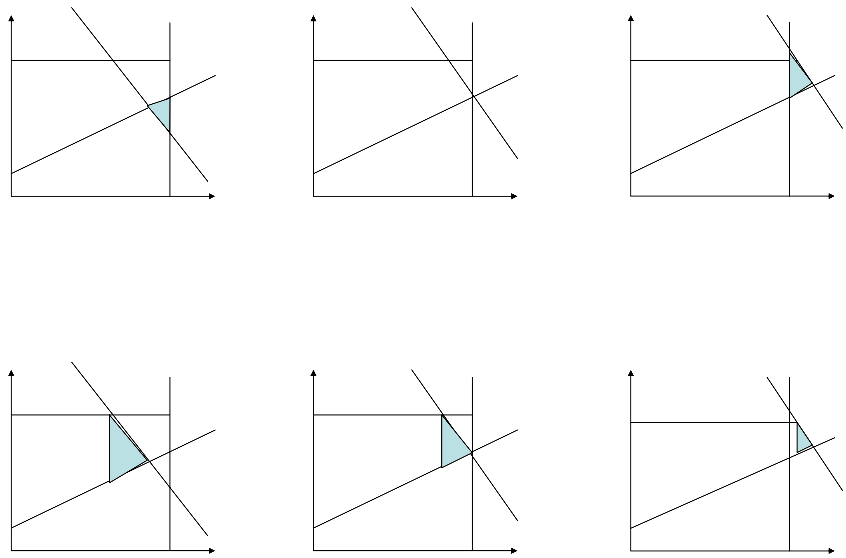


Figure 5.21   Illustration of welfare loss in presence of market power, and with (upper part) and without (lower part) discrepancy between the expressed and the potential demand functions.

Figure 5.21 illustrates the case of market power. The three upper subfigures correspond to those of Figure 5.20, except that now the price is higher due to exercise of market power by firms. The welfare loss is seen to be the same as in Figure 5.20. Thus the welfare loss due to a discrepancy between the potential and the expressed demand functions is independent of the electricity price. Consequently, the welfare loss due to a discrepancy between the potential and the expressed demand functions is independent of exercise of market power.

The three lower subfigures illustrate the situation in case the potential and the expressed demand functions are identical. Now the market price has influence on the welfare loss, and hence exercise of market power will influence the welfare loss.

Assuming that the market price is independent of the demand elasticity seen in the market (a questionable assumption, but acceptable for the sake of the following argumentation), the welfare loss in the three upper subfigures may be directly compared with the welfare loss in the three lower subfigures in Figure 5.21. From reasoning related to such figure it may be concluded that the change in welfare loss by going from the upper subfigures to the lower subfigures may be positive, negative or zero.

In summary, we may distinguish the following comparisons and their results with respect to change in welfare loss:

- Without market power, without a difference between potential and expressed demand functions: If the potential (and hence also expressed) demand function changes (e.g., over time) this will not influence the welfare loss (it remains zero).

- Without market power, with a difference between potential and expressed demand functions: If the situation is changed such that the potential demand function becomes actually expressed, there will be a gain in welfare save for exceptional situations. This is illustrated in Figure 5.20.
- With exercise of market power, without a difference between potential and expressed demand functions: if the elasticity of the demand function is increased there may be an increase, a decrease or no change in the welfare loss. This is the situation analyzed initially in this chapter, see Figure 5.18 and Figure 5.19.
- With exercise of market power, with a difference between potential and expressed demand functions: If the situation is changed such that the potential demand function is actually expressed, there may be an increase, a decrease or no change in the welfare loss. This is illustrated in Figure 5.21.

Validity of assumptions

Comparing the numerical magnitudes as given in Figure 5.18 and Figure 5.19 it is obvious (assuming that the relevant span of demand elasticities are represented in the analyses) that the competition form (or fierceness) and the demand elasticities are highly important determinants for the electricity prices. However, as seen, e.g. from the list of obstacles to competition (see the introduction to the present chapter) there are further important determinants.

For the purpose of the present analysis, the following elements may be singled out as key determinants for the electricity price in a market-based system:

- The available production capacities and marginal costs of production
- Transmission of electricity
- The demand functions for consumption
- Actors and their strategic actions.

Two of the elements are relatively well known quantitatively, while two others are uncertain or unclear. Thus, it may in many contexts be assumed that the marginal cost of electricity production is known with sufficient accuracy to permit substantial quantitative analysis. Similarly, the available transmission links and their capacities are fairly accurately described.

The remaining two items on the list, the consumers' utility and the actors and their strategies, are less established. As concerns the consumers' utilities this is treated under various perspectives elsewhere in this report.

Concerning consumers' strategic actions it is normally assumed that consumers are price takers, so further pondering in this direction is then deemed unnecessary. This line will also be followed her, however, it should be noted that precisely in relation to flexible demand the marked is very small, both in quantity and in the number of actors, so that market power should potentially be a relevant topic here. Indeed, some of the characteristics concerning market power on the electricity supply side, quoted from the Nordic competition authorities report in the introduction to the present chapter, might apply equally well for the demand side, e.g. with respect to market concentration.

There is little direct knowledge concerning the actors' strategic actions on the supply side. Obviously the electricity producers are expected to be profit maximisers, however, this does not suffice to simulate the outcome of a market solution. In continuation of the illustrations given above it is obvious that in order to make a numerical simulation of exercise of market power it will be necessary to specify the supply functions applied, whether they are of the SFE form or the more specific Cournot of Bertrand forms. Specification of the supply functions is, however, just a simple way of summarising the fierceness of competition in a functional form.

In addition a large number of additional considerations are necessary, see, e.g. Nordic competition authorities (2003) or Modelling Imperfect Competition in the Nordic Electricity Market with Balmorel (2005). Suffice to mention that actors need not be competing, since coalitions may be present, mediated, e.g. through cross ownership. Transmission capacities limitations may impede the competition from other countries. Also interrelations with other markets are essential, e.g. the financial markets on the one hand and the regulating power market on the other hand.

Conclusions

- Of the key determinants of the market prices: demand elasticity, marginal production cost, transmission, and competition form/fierceness, the two least known in quantitative terms are demand elasticity and competition.
- The present work deals with demand elasticity, in this section this is treated by parametric calculations, while other chapters quantify it.
- In relation to competition it is extremely difficult to know the strategic thinking of the key actors. In this section, this has been treated by calculations where two competition forms, Cournot and SFE, have been applied.
- An increase in elasticity will imply a decrease (or at least not an increase) in electricity prices. This in turn will imply: redistribution from producers to consumers, potentially more efficient production and better (in the sense of closer to marginal cost) price signals for investments.
- There will be a welfare loss if going from a situation with inelastic residual demand to a situation with elastic residual demand.
- There is no simple relationship between the change in residual demand elasticity and the change in welfare loss. Calculations indicate that as elasticity is increased from zero, the welfare loss initially increases (this is a theoretical result), reaches a maximum, and then starts decreasing.
- The calculations indicate that substantial changes in residual demand elasticity are needed to match the effects with respect to changes in welfare of changes in competition form from Cournot to the less fierce SFE competition.
- An indicative calculation under idealised assumptions suggests that for a Danish situation with two identical firms engaged in SFE competition the maximum annual loss in social welfare, compared to a situation with inelastic demand is DKK 1,625 million, attained at an elasticity of -0.00001, a numerically very small number. This implies that for this situation an increase in the numerical value of demand elasticity above that will decrease the welfare loss.

- For three or more identical firms the maximum welfare loss is attained at a demand elasticity around -0.2. This means that if it is believed that presently the demand elasticity is numerically smaller than that, an increase in the numerical value of demand elasticity will increase the welfare loss.
- Presence of, typically small, price taker firms may be seen as implying an elastic residual demand, and therefore has the same effect for the results as consumers' demand.
- In case there is a difference between the demand function expressed in the market and the consumers' potential demand function the analytically indecisive nature of the situation remains unchanged.
- It is difficult to estimate to which extent the analysed examples are sufficiently relevant for the present situation. In particular it may be questioned if the competition may be modelled as done here, and to which extent, e.g. political factors are determinant for the imperfect competition aspects.
- Assuming that the analysed situation and the applied method hold sufficient relevance, the absolute key question is whether the present situation is more close to the two firms' case or the three firms' case. In the former case, increase in demand elasticity matters, while in the latter case there is no clear advantage, or even a disadvantage, from increasing the demand elasticity.

6 Conclusion

The report describes demand response in the electricity sector. A microeconomic perspective is provided, and the report includes empirical observations and case studies.

The report aims at evaluating benefits from demand response. Applying different methods for evaluating benefits from demand response, various elements contributing to the overall value are presented. However, these elements are not directly additive. The focus is on benefits for society, although costs of increasing demand response are not included.

Important topics related to short-term demand response are the notification, duration and frequency of a needed demand response. Problems, actions, incentives and therefore also costs and the value of demand response vary with the notification time, duration and frequency of a response. Within seconds the problem is balancing demand and supply, maintaining the net frequency and security of supply. Actions have to be automatic, and the incentive for individual consumers to participate in solving a problem is often an optional agreement with a predetermined payment. Within a day ahead, the problem may be planned production on expensive capacity in just one hour and an action may be shifting demand to another hour (load-shifting) or reducing demand (peak clipping). Within this time scale, incentives may be price-based and possibly supplemented by automatic information on prices.

In this report, demand response actions addressing different problems at different time scales are evaluated. However, actions on one time scale may solve a problem, or part of a problem, on another time scale. As interactions between time scales are complex, and effects of demand response at one time scale on problems at another scale are unclear, values of demand response on different time scales addressing different problems may not be added directly.

Therefore, the report includes elements valuing parts of demand response but does not give an overall value of increasing demand response. Also, the report focuses on the value for society, although for the implementation of demand response activities, who gains and who pays is important. The report focuses on market efficiency and security of supply, while elements related to reduced volatility of prices and quantities, e.g. hedging costs or insurance values are not evaluated.

6.1 The value of demand response

Looking at improvements in the market efficiency, section 4.3 evaluates the social welfare gain from exposing consumers to hourly prices in the Nord Pool spot market, and section 5.2 addresses the value of market power mitigation. In both analyses a crucial parameter is the price elasticity of demand at an hourly time scale. According to empirical observations of the Danish electricity consumption this is quite low today, reflecting both a large share of consumers not exposed to hourly prices and a limited elasticity for consumers actually exposed to hourly prices. However, one issue of demand response is exactly how to increase the price elasticity of demand. In the literature estimated price elasticities vary considerably but are generally larger than the observed elasticities for Denmark. The value of demand response has been analysed and evaluated for a range of price elasticities, see sections 4.3 and 5.2.

Assuming a price elasticity of -0.1, exposing consumers to hourly Nord Pool prices, over the years 2001 to 2004 might have produced an annual welfare gain of DKK 18 million per year. This value only indicates a size and should be taken with some caution as it is based on simple assumptions. In addition, costs related to obtaining the gain (interval metering and exposing consumers to time-varying prices) and possibly saved investments in peak capacity are not included.

Other conclusions from the analyses in section 4.3 are:

- The welfare gain varies considerably both with the assumed price elasticity and with the actual price variation.
- Most of the gain is ascribed to hours with high prices. However, also very low prices contribute significantly to the welfare gain.
- Large fixed price-additives (TSO/DSO tariffs, taxes etc.) reduce the quantitative adjustment (assuming a fixed price elasticity) and thus the welfare gain.

The analyses in section 4.3 indicate that with the present tax structure, demand response activities should focus on large consumers, possibly quite specific consumers capable of following hourly prices and reacting accordingly. If small companies and private households are to be engaged, either response to prices should be automatic, information about extreme prices should be distributed directly to the consumers, or time-of-use rates, giving an incentive for load-shifting should be used.

Concerning market power, increased demand response may reduce the profit from exercising market power and thereby the incentive to do so. The analyses in section 5.2 show that with only two equally sized competing suppliers of electricity in Denmark (treating Denmark as an isolated price area), increased demand response may decrease electricity prices considerably. However, increasing the number of competing companies in the market by just one or two would imply an equally sized reduction in the price.

Concerning figures, an annual welfare loss of 720 MDDK/year has been calculated on the basis of a situation with two companies and a price elasticity of -0.1, compared to a situation with perfect competition. If the price elasticity increases to -0.2, the welfare loss decreases to DKK 521 million per year. However, the welfare loss is not a monotone decreasing function of the price elasticity. For example, if the residual demand price elasticity is zero, quantity adjustments to price changes are zero and no welfare loss is observed.

Again, figures are only indicative. However, if the assumptions of the analysis hold relevance, whether increasing demand response in order to decrease market power generates a welfare gain hinges mainly on whether two or more firms are competing in the present market. If two firms compete, a welfare gain may be obtained by increasing demand response, but if three or more firms compete, increased demand response may generate a welfare loss.

In any case, an increase in the demand elasticity will imply a reduction in the electricity price in a situation where market power is exercised. This will provide better (in the sense of closer to marginal cost) price signals for e.g. load dispatch and investments.

Security of supply problems, mainly related to peak demand or system failures, often require response at short notice and for a limited duration. For these problems, the value of demand response mainly derives from saved investments in peak capacity and saved costs of disconnecting consumers. The compensation levels required for consumers to accept controlled disconnections/interruptions in electricity supply is one way to evaluate the value of security of supply. A pilot study targeting the needed compensation for automatic interruptions of consumers with a dishwasher, a washing machine and a dryer is presented in section 4.4. The main conclusions from the analysis are:

- The required mean compensation levels are high. However, a significant share of the consumers require a much lower level of compensation.
- Consumers appear to require a threshold compensation for entering an agreement, i.e. per hour disconnected. Agreements specifying many and long disconnections are cheapest.

Another conclusion is that the choice of appliances targeted is crucial for the level of compensation required. Disconnecting a dishwasher etc. implies a discomfort to the consumer. Other appliances like an electric water heater, a freezer or a refrigerator may be disconnected for a short period without any discomfort to the consumer, and required compensation levels for shortly disconnecting these appliances should be much lower or even zero.

Finally, looking at total system costs, alternative options for solving critical situations are evaluated in section 5.1. A main conclusion from this analysis is that most of a gain from demand response is associated with very few critical situations and that a correct representation of these cases is crucial for the valuation of demand response. Regarding average gains, the simulations show that peak clipping demand response is competitive to the present reservation costs of reserve capacity in the Statnett Regulation Power Option Market, and that load shifting may be competitive. However, costs of implementing demand response are not included.

6.2 How to enhance demand response?

As regards market efficiency and security of supply, instruments to enhance demand response are quite different.

Concerning market efficiency, the key issues are to expose consumers to time-varying prices reflecting the varying costs of production and transport of electricity and to increase short-term flexibility of demand.

A precondition for exposing consumers to time-varying prices is the installation of interval meters. Today users with a yearly demand of more than 100,000 kWh have interval metering, corresponding to a little more than 50% of total electricity consumption. A large-scale roll-out of interval meters to all consumers may immediately and alone add only marginally to increasing demand response. However, benefits from interval meters are diverse. Over time, the ability to benefit from interval meters may increase due to new technology, e.g. new electrical products, advanced tariffs and enabling technologies. In addition, interval metering gives consumers the possibility to express preferences and may improve the fairness of the system.

So far it has been decided to replace about 13% of the current stock of Danish meters with interval meters. If the major part of the new meters should be advanced interval meters, some regulation may be needed.

At present numerous interval metering systems including different additional facilities exist and a common standard has not yet been defined. Before a large-scale roll-out of interval meters is carried out, a common standard should be defined, and it should be analysed which facilities to include in a meter and which facilities should be obtained by other technologies, e.g. the internet.

Assuming interval metering is established, increasing the consumers' reactions to prices is the next problem. The present price structure, where the energy part of what households pay for the electricity is about 20%, implies that the private benefit from adjusting to changes in the electricity price is minor. For companies and large consumers a larger share of the total bill is related to the cost of electricity and this increases the incentive for adjusting to price changes. The tariffs used for transport of electricity as well as for ancillary services could be developed to be more dynamic, reflecting the dynamic costs of these and increase the incentive for demand response.

Another issue related to the electricity price is the information cost of knowing the time-varying prices. Introduction of time-of-use rates is one way to obtain time-varying rates, giving an incentive for load shifting and obtaining part of the welfare gain relative to fixed rates. However, time-of-use rates are statistical average rates not reflecting the actual costs of electricity production. Time-of-use rates are a second best solution that can realise a share of the possible welfare gain with a minimum of information cost. As regards peak demand, superimposing an extra high tariff at critical hours may be argued. However, this requires consumers to obtain information concerning critical hours.

Concerning enabling technologies, smart meters or another technology sending a price signal and appliances automatically reacting to prices may be a future option. This implies that real-time pricing is manageable by consumers and that considerable flexibility in demand may be observed, e.g. electrical vehicles and water heaters loading at low prices and cutting off at high prices.

Regarding security of supply, demand response actions have to be with a short notice. Demand can be disconnected within milliseconds, which is much faster than increasing generation. Terms for participating in demand response programmes have to be agreed in advance, and if many small consumers are involved, response has to be automatic or controlled centrally. Today, many types of ancillary services are paid with a reservation price (involving contracts and control measurements), but in the future the arrangement can be developed to be voluntary and price driven (combined with statistical control). This could be a way to activate the demand side on a massive scale and obtain the services at lower costs and at a better quality. It should be noticed that security of supply problems only occur a few critical hours per year, and in the majority of these cases a limited demand response may solve the problem. However, it is also these cases that dominate the aggregated value of demand response.

The present strategy of identifying and approaching large consumers with thermal storage facilities, where interruptions of limited duration gives minimal discomfort, appears to be a reasonable strategy and may supply the necessary demand response in most of the critical situations.

In the future, enabling technologies disconnecting specific uses when needed appear promising, e.g. frequency-controlled interruptions of specific appliances or price signals automatically disconnecting uses that may wait.

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Annex I. Equations for the calculation of the equilibrium price and welfare gain by changing from average to hourly pricing

Assuming demand and supply curves with constant elasticities we have:

Demand:

$$\frac{q_1}{q_2} = \left(\frac{p_1}{p_2}\right)^{\alpha} \Rightarrow q_1 = q_2 \cdot \left(\frac{P_1}{P_2}\right)^{\alpha}$$

Supply:

$$\frac{q_1}{q_2} = \left(\frac{p_1}{p_2}\right)^{\beta} \Rightarrow q_1 = q_2 \cdot \left(\frac{P_1}{P_2}\right)^{\beta} \qquad \text{(A1)}$$

α : Demand elasticity (negative).
P : Price.
q : Quantity.

β : Supply elasticity (positive).
P : Price.
q : Quantity

(P_1, q_1) and (P_2, q_2) are two arbitrary points on the curve in question.

Due to grid payment, VAT and taxes there is a price shift T between supply and demand. If in a price equilibrium the supply is paid P_t, then the consumer has to pay $P_t + T$. If we let the symbol P denote prices without taxes etc., then the demand curve is given by:

$$q_1 = q_2 \cdot \left(\frac{P_1 + T}{P_2 + T}\right)^{\alpha} \qquad \text{(A2)}$$

The formulas for demand and supply curves can alternatively be expressed by:

Demand:

$$P_1 = (P_2 + T) \cdot \left(\frac{q_1}{q_2}\right)^{1/\alpha} - T$$

Supply:

$$P_1 = P_2 \cdot \left(\frac{q_1}{q_2}\right)^{1/\beta} \qquad \text{(A3)}$$

T : Price shift (VAT, taxes, etc.).

Figure A1 shows the equilibrium, i.e. the situation where the size of the traded amount makes supply and demand prices (excluding taxes etc.) equal. The equilibrium is indicated by subscript t.

If the consumer price (excluding taxes etc.) is fixed at P_o, then the consumer will buy the amount q_o given by the demand curve. The area of the shaded triangle is the welfare gain that could be achieved by increasing the amount q_o to the optimum amount q_t.

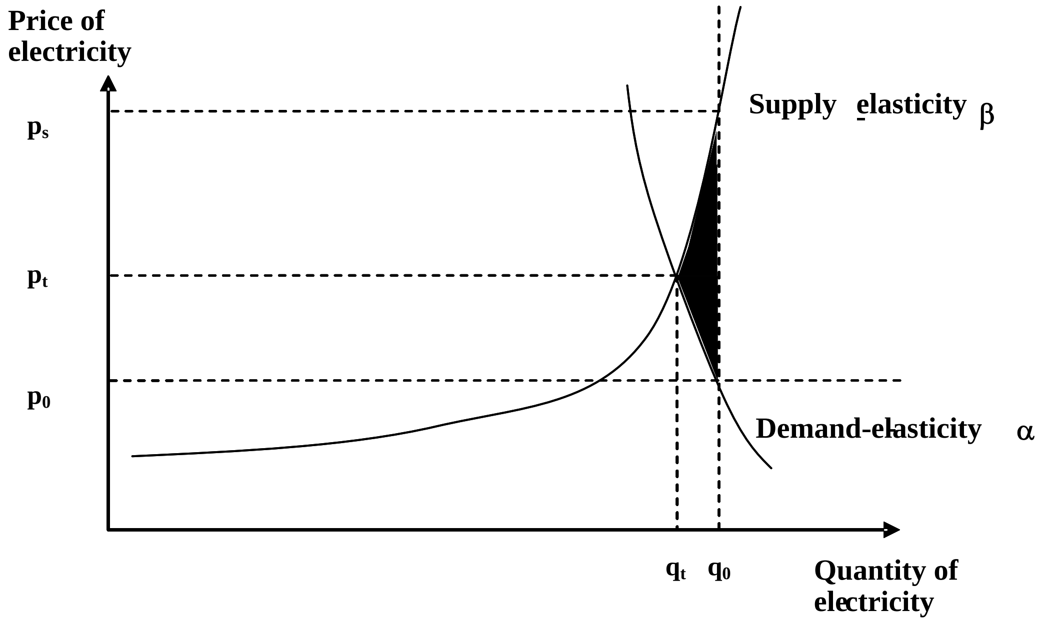

Figure A1 The equilibrium situation. The public welfare is given by the size of the two shaded areas.

The welfare gain that can be achieved by changing from a fixed consumer price P_o to the optimum price P_t (equivalent to changing from amount q_o to amount q_t) is found by integrating Eqs. (A3):

$$W = \int_{q_o}^{q_t} \left(P_\alpha - P_\beta\right) \cdot dq = \int_{q_o}^{q_t} P_\alpha \cdot dq - \int_{q_o}^{q_t} P_\beta \cdot dq$$

$$W = \int_{q_o}^{q_t} \left(\left(P_t + T\right) \cdot \left(\frac{q}{q_t}\right)^{1/\alpha} - T \right) \cdot dq - \int_{q_o}^{q_t} P_t \cdot \left(\frac{q}{q_t}\right)^{1/\beta} \cdot dq$$

$$W = \left(P_t + T\right) \cdot \int_{q_o}^{q_t} \left(\frac{q}{q_t}\right)^{1/\alpha} \cdot dq - T \cdot \int_{q_o}^{q_t} dq - P_t \cdot \int_{q_o}^{q_t} \left(\frac{q}{q_t}\right)^{1/\beta} \cdot dq$$

$$W = \frac{\left(P_t + T\right) \cdot q_t}{1 + 1/\alpha} \cdot \left[\left(\frac{q}{q_t}\right)^{1+1/\alpha} \right]_{q_o}^{q_t} - T \cdot \left[q\right]_{q_o}^{q_t} - \frac{P_t \cdot q_t}{1 + 1/\beta} \cdot \left[\left(\frac{q}{q_t}\right)^{1+1/\beta} \right]_{q_o}^{q_t}$$

$$W = \frac{\left(P_t + T\right) \cdot q_t}{1 + 1/\alpha} \cdot \left[1 - \left(\frac{q_o}{q_t}\right)^{1+1/\alpha} \right] - T \cdot \left[q_t - q_o\right] - \frac{P_t \cdot q_t}{1 + 1/\beta} \cdot \left[1 - \left(\frac{q_o}{q_t}\right)^{1+1/\beta} \right]$$

$$W = T \cdot \left[q_o - q_t\right] - \frac{\left(P_t + T\right) \cdot q_t}{1 + 1/\alpha} \cdot \left[\left(\frac{q_o}{q_t}\right)^{1+1/\alpha} - 1 \right] + \frac{P_t \cdot q_t}{1 + 1/\beta} \cdot \left[\left(\frac{q_o}{q_t}\right)^{1+1/\beta} - 1 \right] \qquad \text{(A4)}$$

Eq. (A4) is valid for $P_o < P_t$ as well as for $P_o > P_t$.

Calculations

We assume that demand and supply curves have constant known elasticities α and β. Moreover, we assume that we know the fixed consumer price P_o and the corresponding traded amount q_o and price of supply P_s. Also the price shift T is known.

P_t is then found by solving Eq. (A5) which is equivalent to solving Eq. (A6). This cannot be done analytically, but must be done by iteration.

$$q_0 = q_t \cdot \left(\frac{P_o + T}{P_t + T} \right)^{\alpha} \;\wedge\; q_0 = q_t \cdot \left(\frac{P_s}{P_t} \right)^{\beta} \tag{A5}$$

$$\Leftrightarrow \left(\frac{P_o + T}{P_t + T} \right)^{\alpha} = \left(\frac{P_s}{P_t} \right)^{\beta} \tag{A6}$$

When P_t is known, q_t can be found from Eq. (A7):

$$q_t = q_o \cdot \left(\frac{P_t}{P_o} \right)^{\beta} \tag{A7}$$

Finally, the gain W can be found from Eq. (A4).

List of symbols

q	Amount of electricity.
P	Price of electricity.
α	Demand elasticity.
β	Supply elasticity.
P_o	Fixed consumer price.
q_o	Traded amount.
P_s	Supply price.
T	Price shift between supply and demand (grid payment, VAT and taxes).
P_t	Price of electricity in equilibrium.
q_t	Traded amount of electricity in equilibrium.

Calculation of the supply elasticity β

From 0 to 48,000 MW the price at Nord Pool varies from 0 to 10 øre/kWh (based on data from Energistyrelsen, 2005) implying a Nord Pool price elasticity of:

$$\frac{\frac{\Delta q}{q}}{\frac{\Delta p}{p}} = \frac{\frac{48000}{24000}}{\frac{10}{5}} = \frac{2}{2} = 1$$

Assuming three levels of fixed additions to the price of 20.7 øre/kWk, 37.5 øre/kWh and 146.3 øre/kWh respectively gives elasticities of:

$$\frac{\frac{48000}{24000}}{\frac{10}{25.7}} = 5.14 \qquad \frac{\frac{48000}{24000}}{\frac{10}{42.5}} = 8.50 \quad \textit{and} \quad \frac{\frac{48000}{24000}}{\frac{10}{151.3}} = 30.26$$

From 48,000 MW to 58,000 MW the Nord Pool price increases from 0.10 øre/kWh to 0.20 øre/kWh. At Nord Pool prices this equals an average price elasticity of:

$$\frac{\frac{\Delta q}{q}}{\frac{\Delta p}{p}} = \frac{\frac{10000}{53000}}{\frac{10}{15}} = \frac{0.1887}{0.6667} = 0.283$$

From 58,000 MW to 66,000 MW the Nord Pool price increase from 0.20 øre/kWh to 0.60 øre/kWh, giving a Nord Pool price elasticity of:

$$\frac{\frac{\Delta q}{q}}{\frac{\Delta p}{p}} = \frac{\frac{8000}{62000}}{\frac{40}{40}} = \frac{0.129}{1} = 0.129$$

The supply curve at Nord Pool is assumed to have piece-wise constant elasticity with three levels:

- From 0 to 48,000 MW an elasticity of 1.0
- From 48,001 MW to 58,000 MW an elasticity of 0.283
- From 58,001 MW to the capacity limit 66,000 MW an elasticity of 0.129

Risø's research is aimed at solving concrete problems in the society.

Research targets are set through continuous dialogue with business, the political system and researchers.

The effects of our research are sustainable energy supply and new technology for the health sector.