Tariff scheme options
for distribution system operators
Preface

This research report provides the results of the research project “Tariff scheme options for distribution system operators”. The research was conducted by a research group of LUT Energy, the members of which were Professor Jarmo Partanen, Dr. Samuli Honkapuro, Jussi Tuunanen, M. Sc. (Tech), and Dr. Hanna Niemelä. The research was funded by the Finnish Energy Industries and the Finnish Electricity Research Pool.

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1 Introduction

Significant changes are taking place in the generation and end-use of electrical energy. The principal target of these changes is savings in the primary energy and reduction in energy production emissions. Here, deployment of renewables such as wind and solar energy and distributed generation play a key role. However, typical drawbacks of these forms of generation are their low predictability and small unit size. In the end-use, improvements in energy efficiency and controllability have an impact on both the volume and characteristics of electricity consumption. In addition, advancements in battery technology will open up new opportunities for the storage of electrical energy, thereby altering the nature of the whole power system. Moreover, smart grids enable flexible connection of distributed generation (DG), energy storages and controllable loads to the grid and their smart control.

In order for the above-described changes in the energy system to take place in a cost-efficient way from the perspectives of end-customers and enterprises in the field, demand response (DR) and related incentive tariff schemes are required both in the distribution and retail of electricity. Demand response enables distributed generation and an optimal use of the generation and network capacity. The improved capacity utilisation rate, in turn, reduces investment needs, thereby decreasing the costs to the end-customers in the long term. For distribution system operators (DSOs), improvements in energy efficiency and distributed energy storages will have an impact on the amount of electrical energy transmitted in the distribution systems, peak power and the temporal variation in power demand. As the peak power determines the network dimensioning requirements, and, on the other hand, the present tariffs are based on the amount of transmitted energy, the above changes will influence both the costs and revenues of electricity distribution. For the energy sector, problems may arise, if the changes in energy and power are such that the prevailing tariff system is not able to respond to the revenue stream needs of the DSO in the new operating environment.

Furthermore, advancements in the control and metering of the customer gateway provide technical opportunities for more dynamic tariff schemes, by which the consumption behaviour of end-customers can be steered to a direction that is optimal for the electric power system. In that case, the end-use is efficient and scheduled to guarantee an optimal use of resources in generation, transmission and distribution alike. The starting point here is that the network has to enable market-
based demand response, which, however, may not lead to network investments that are non-optimal for the national economy. Yet, in practice, demand that is optimised based on generation only may be non-optimal from the viewpoint of the distribution system, in which case the demand response products in electricity retail may produce conflicts of interest between the retailer and the DSO in the load control. With a suitable distribution tariff scheme, incentives can be provided for the consumers to optimise their electricity consumption so that besides the customer and the retailer, also the DSO benefits from the demand response.

The objective of the research is to study which opportunities and requirements the future operating environment provides for a distribution tariff scheme for DSOs. The research investigates how different tariff schemes encourage customers in energy efficiency, how they enable introduction of active resources such as demand response, and how they guarantee an optimal use of the distribution network capacity and appropriate revenue streams for the DSO. The primary target is to analyse what kind of a tariff scheme ensures the cost reflectivity of customer invoicing and an optimal use of the distribution system capacity, simultaneously allowing the market-based demand response of small-scale customers. The study focuses on small-scale customers; in practice, low-voltage customers, who at present do not have a power tariff of their own in Finland.

The structure of the report is as follows. Chapter 1 concludes with a brief review of the research conducted recently on the topic. Chapter 2 discusses the effects and target state of the distribution network tariff schemes from the viewpoints of different stakeholders. The chapter also analyses the boundary conditions for the development of the tariff scheme. Chapter 3 addresses the present tariff schemes and their key development needs in Finland. Chapter 4 introduces potential tariff schemes, and Chapter 5 concentrates on power band pricing and its effects. Chapter 6 provides conclusions, and Chapter 7 discusses the future research needs on the topic.

1.1 Previous research on tariff schemes

Kärkkäinen & Farin (2000) have investigated distribution tariff schemes in distribution networks soon after the opening of the Finnish electricity market. The study lists the most common requirements for the tariff schemes, such as cost reflectivity, equal and non-discriminating treatment of customers, freedom of choice, intelligibility, consistency and steering properties. It has been shown that these requirements are somewhat contradictory, because for instance full cost reflectivity would require complicated and geographically varying tariffs, which would be against
the requirements set for spot pricing and intelligibility of the tariffs. Considering the steering aspects of tariffs, it has been suggested that the tariffs should encourage efficiency in the network dimensioning and the use of network capacity, simultaneously promoting efficient use of energy. The study considers the proportions of fixed charges and energy rates in the tariffs of the DSOs. The fixed charges are shown to vary between 0 and 80%, depending on the DSO and the customer group. Hence, it has been concluded that the decision on the proportions of fixed charges and energy rates should be left to the DSOs.

Evens & Kärkkäinen (2010) have studied pricing mechanisms and incentive systems by which demand response can be promoted. The study provides a review of the theory related to the pricing mechanisms and analyses 15 pilot studies. The study focuses on both network and retail tariffs, and the incentive systems are divided into price- and incentive-based ones. In the price-based systems, the consumer prices vary, and the consumer’s response to changes in prices is voluntary. In incentive-based systems, the consumers receive compensation, if they allow load control. Considering the research on distribution tariffs, a highly relevant observation is that in Norway the regulator has banned the DSOs from using Time-of-Use tariffs (ToU), because they are suspected to cause potential disturbance to the normal market operation.

Similä et al. (2011) have investigated the distribution network tariff scheme in a smart grid environment by a literature review, economic theory and simulations. The simulation results show that the end-customer benefits most when the retail and distribution tariffs are dynamic (in practice, a tariff based either on market price or time of use). In addition, it is stated that dynamic tariffs improve the cost efficiency of the DSO; however, the incentive effects of dynamic tariffs may be problematic to the DSO, because the customers’ responses to the load control lead to a decrease in the company revenues, while the short-term costs remain unchanged. Thus, the prices have to be raised in order to cover the costs, which, for the customers, is negative feedback on their responses to the incentive system. Furthermore, the study recognises problems related to the load control performed by the DSO. As to this, it is concluded that the network tariffs should be static, and only the retail tariffs could vary dynamically within a day. If the DSO wishes to use load control to balance the network load, it should buy the load control from the retailer.
2 Effects of the distribution network tariff scheme and boundary conditions for development

The starting point for a pricing structure of energy services, such as electricity distribution, has to be in encouraging the energy efficiency of the system as a whole and in minimising the environmental effects and costs of energy generation to the national economy. In practice, this means measures to enable distributed generation and demand response, optimisation of the use of generation, transmission and distribution capacity, and minimisation of fuel and other variable costs. Here, it is emphasised that both energy and power have an impact on the overall energy efficiency of the electric power system, and therefore, a pricing system that only encourages in minimising the energy use does not necessarily produce an optimal result, but incentives are required to reduce the peak power and optimise the temporal variation of power.

When considering the pricing of electricity distribution, we may state that in addition to the above targets, the pricing system has to ensure reasonable and predictable revenue stream and encourage the customers to control their electricity use in a way that is optimal for the distribution system. As there are also other players in the electricity market besides customers and DSOs, such as producers, retailers and the transmission system operator (TSO), the interests of these stakeholders have to be taken into account in an optimally designed distribution tariff. For instance, a distribution and retail tariff may not produce control signals that conflict with each other. Furthermore, a customer’s opportunities to operate have to be safeguarded by ensuring the reasonableness, intelligibility and feasibility of pricing and the related incentive elements for a common electricity end-user. The above-described requirements can be expressed by stating that a distribution tariff shall balance the maximisation of national economic profit and minimisation of the adverse effects experienced by an individual customer.

According to a survey by Nemesys (2005), all the interest groups put special emphasis on stability when considering the criteria for a well-functioning regulatory model. Figure 2.1 shows that stable tariffs are equally important or even more important than low tariffs for all interest groups. Although the emphasis in this study is on the regulatory model, the results can be extended, at least in this respect, to cover the targets set for the tariff scheme.
The following sections discuss the objectives and effects of the distribution network tariff scheme in more detail from the perspectives of different interest groups.

### 2.1 Distribution system operator perspective

From the perspective of a distribution system operator, the tariffs shall guarantee an adequate and predictable revenue stream, which enables the construction, operation and maintenance of a distribution system that meets the requirements set by the customers and the operating environment.

In addition, the tariff scheme has to be cost reflective to ensure that changes in the use of electricity affect the revenues and costs as equally as possible. The distribution network components, such as conductors and transformers, are dimensioned according to the power demands of the network. Hence, the dimensioning of these components is influenced both by the power demands of individual customers but also by the peak power of a larger customer volume (supply area of a distribution transformer, feeder, primary substation), which, again, is affected by the intersecting load curves of individual customers. In the electricity distribution operations, energy-based cost factors are basically comprised of the load losses on the network and the charges of the transmission system operator. On the other hand, costs that depend on the number of customers include metering and billing and, to a certain degree, administrative costs. The network operation costs, such as operation, maintenance and fault repair, mainly depend on the scope of the network and the operating environment. Figure 2.2 illustrates a typical cost distribution of a distribution system.
operator. The figure shows that capital costs (investments and financing), which depend mainly on power, account for more than half of the costs. The costs of the main transmission grid, similarly as the distribution network costs, are chiefly dependent on power, but the invoicing in the main transmission grid is based on the volumes of transmitted energy. Thus, only the network losses constitute a cost component that is chiefly dependent on energy. The losses are divided into network and transformer losses, the latter of which can be further divided into load and no-load losses. Of these, only the transformer no-load losses are independent of the power transmitted on the network. Hence, less than 6% of all costs are energy-based costs.

In addition to the revenue stream, the steering effects of pricing have to be taken into account. If the pricing is based solely on power or the use of energy, it steers the customers to optimise their energy use with the target to reduce the costs. Hence, the objective of the DSO is to generate a tariff scheme that encourages the customers to adjust their use of electricity to be optimal for the distribution system. In theory, in an ideal situation, the power demand would be as balanced as possible in order to make the maximum use of the network transmission capacity. In addition to the above, there is a technical requirement that the distribution tariff shall not require meterings that would cause significant additional costs. The target is that the minimum requirements defined for metering in the Government Decree (66/2009) on determination of electricity supply and metering are adequate for the implementation of the tariff scheme.
2.2 Customer perspective

The proportion of electricity distribution of a customer’s total electricity bill is approximately a quarter, as shown in Figure 2.3. In the figure, the proportionally small cost component, that is, transmission on the main transmission grid (2 %) is billed also in connection with the electricity transmission on the distribution network. Electricity transmission on the distribution network, similarly as sales of other services, is subject to VAT, in addition to which the electricity taxes are charged to the customers in connection with the transmission of electricity. Nevertheless, the analyses in this study concentrate on the price of electricity transmission on the distribution network without taxes.

Figure 2.3 Electricity price formation for a domestic customer on 1 February 2012 (EMA 2012a).

The figure above can be further divided into energy-based and fixed parts in the electricity bill. Energy-based items are the electricity purchase and retail and the VAT included in these, and the electricity taxes, while the transmission of electricity on the distribution network and on the main transmission grid are mainly power-based cost items. Figure 2.4 depicts the information of Figure 2.3 divided into energy-based and fixed charges, assuming that a fixed charge is used in the electricity distribution. The figure shows that also in this case 65 % of a customer’s electricity bill is comprised of energy-based charges, which guarantees that the billing encourages the customers to reduce their use of energy even if the distribution network tariff scheme is based on a fixed standing charge only.
Favourable prices are naturally among the customers’ primary interests. The pricing of the DSOs is supervised by a regulatory model, which in practice sets a maximum limit on the company turnover. However, the focus of this study is on the tariff scheme only, and it is assumed that the level of tariffs is sufficient for the DSO to guarantee adequate revenue streams required for operation. Besides favourable prices, a key pricing criterion for a customer is predictability, in addition to which the tariffs are expected to be intelligible so that the customer understands how the electricity bill is compiled and how he/she can affect his/her bill. As it was stated above, predictability is at least as important to the customer as the favourable pricing. Equal treatment of customers, on the other hand, requires that the tariffs are cost reflective and transparent. Moreover, the tariff should be compatible and in line with the retail tariff so that both tariffs encourage the customer to improve energy efficiency in the use of electricity and do not include any contradicting incentive elements.

Customers often see changes as negative occurrences. When the tariff scheme is reformed, it is inevitable that for some customers the prices will rise and drop for others, even if the turnover of the DSO remains unchanged, and the tariff scheme is now more cost reflective. When the target is to achieve a tariff scheme that steers the use of electricity in a direction that is more optimal for the whole energy system, we have to consider our priorities: the benefit of the national economy or an individual customer’s security in the reform. The starting point is that the reform of the tariff scheme will steer the electricity users to make better use of the distribution capacity, which will lead to a decrease in the distribution costs in the long term. Thus, the reform will benefit the customers in the long term, even though the changes may have negative effects in the short term.
2.3 Impacts and opportunities of demand response

Vital for the energy system as a whole is that the distribution and retail tariffs together provide incentives for the electricity end users to act in such a way that the national economic benefit is maximised. When the objective is to optimise the utilisation of the generation and network capacity, simultaneously promoting the use of renewables such as wind and solar power, the implementation of demand response plays a key role. In practice, demand response is carried out either manually by the customer or by active load control, or by remote customer load control according to the demand. The remote control is carried out either by the electricity retailer, aggregator or the DSO. In practice, load control has a significant impact on the retailer’s electricity trade balance, and therefore, it is natural that the retailer takes care of the control. If the control were carried out by some other party, this would degrade the accuracy of the load forecast, thereby increasing the balance error and electricity purchase costs. However, the load control carried out by the retailer may in some cases have negative effects on the DSO. For instance, according to the objectives of the retailer company, an optimised demand response may increase the power peaks of the DSO, in which case the costs of the DSO will increase, while the retailer receives financial benefit from the load control.

An example of such a conflict of interest is illustrated in Figure 2.5, where the total power of a single medium-voltage feeder is demonstrated with the area price Finland in the spot market for one day (22 February 2010). The figure shows that the prices are highest during the lowest powers, and the latter price peak is removed close before the time instant of the peak power. If the customer loads were controlled based on the spot price, the demand would shift later from the moment of the first price peak, which would probably increase the power of the feeder.
For an electricity retailer, the load control during price peaks would be very profitable. The retailer could either sell the excess electricity in the market or avoid expensive extra purchases. In the above situation, the area price varies between 100 and 1 400 €/MWh, while the price charged to a domestic consumer is 60–70 €/MWh (6–7 cent/kWh).

Again, the theoretical potential of load optimisation for the DSO can be assessed by a simplified example. The total amount of energy supplied by all DSOs to the customers was 52 TWh in Finland (2010). In the same year, the sum of the annual highest hourly mean power was 11 900 MW. Thus, the peak operating time of the networks is 4 380 hours, and the network capacity utilisation rate is 50 % (peak operating time/8760). It is pointed out here that the calculation is simplified, and the results vary considerably between the distribution system operators. However, the example allows us to assume that the volume of energy transmitted in the present distribution systems could be doubled, if the power demand were distributed evenly to every hour of the year. In Finland, the total replacement value of the distribution networks is about 14 bn €, which, with a 40-year lifetime and 5 % interest rate, yields an annual cost of 815 M€/a. In practice, by the load control, the load peaks can be cut so that an increase in the energy consumption will not require extra reinforcement of the network. In the best case, the volume of energy transmitted on the distribution network could be doubled without additional investments. If the alternative is to carry on with the present load rate, we may assume that the load control would prevent an additional cost of 815 M€/a, if the annual amount of energy were double the present amount, that is, 104 TWh. The highest theoretically possible cost benefit for the national economy would thus be approx. 8 €/MWh, that is, 0.8
Here, it is emphasised that if the loads were controlled by optimising the use of the distribution network capacity as described above, the potential for market-based demand response would be lost. Therefore, it is essential to aim at a total optimisation where a compromise is reached between the benefits of the generation and the network.

### 2.4 Legislation regulating the tariff scheme

Laws and regulations that affect the selection of the tariff scheme include EU directives, the Finnish Electricity Market Act (386/1995), Laki energiamarkkinoilla toimivien yritysten energiatehokkuuspalveluista (1211/2009) (Act on energy efficiency services of enterprises operating in the energy market) and Valtioneuvoston asetus sähköntoimitusten selvityksestä ja mittauksesta (66/2009) (Government Decree on determination of electricity supply and metering).

According to Article 10 of 2006/32/EC

“Member States shall ensure the removal of those incentives in transmission and distribution tariffs that unnecessarily increase the volume of distributed or transmitted energy. In this respect, in accordance with Article 3(2) of Directive 2003/54/EC and with Article 3(2) of Directive 2003/55/EC, Member States may impose public service obligations relating to energy efficiency on undertakings operating in the electricity and gas sectors respectively.”


Item 4 of Article 12 has remained similar to Article 10 of the directive in force, and thus, no changes have been made in this respect to the requirements of the proposal for the directive.

Furthermore, Annex XI “Energy efficiency criteria for energy network regulation and for network tariffs set or approved by energy regulatory authorities” of the above-mentioned proposal for the directive provides more detailed regulations on network tariffs:

1. Network tariffs shall accurately reflect electricity and cost savings in networks achieved from demand side and demand response measures and distributed generation, including savings from lowering the cost of delivery or of network investment and a more optimal operation of the network.
2. Network regulation and tariffs shall allow network operators to offer system services and system tariffs for demand response measures, demand management and distributed generation on organised electricity markets, in particular:
a) the shifting of the load from peak to off-peak times by final customers taking into account the availability of renewable energy, energy from cogeneration and distributed generation;

b) energy savings from demand response of distributed consumers by integrators;

c) demand reduction from energy efficiency measures undertaken by energy service companies and ESCOs;

d) the connection and dispatch of generation sources at lower voltage levels;

e) the connection of generation sources from closer location to the consumption; and

f) the storage of energy.

For the purposes of this provision the term “organised electricity markets” shall include over-the-counter markets and electricity exchanges for trading energy, capacity, balancing and ancillary services in all timeframes, including forward, day-ahead and intra-day markets.

3. Network tariffs shall be available that support dynamic pricing for demand response measures by final customers, including:

a) time-of-use tariffs;

b) critical peak pricing;

c) real time pricing; and

d) peak time rebates.

Based on the above, we may state that no obvious inconsistencies were detected in the present directive or the proposal for the directive that would prevent the implementation of the tariff scheme discussed in this report.

In the Finnish legislation, the key regulation concerning the tariffs is Section 14 of the Electricity Market Act (386/1995):

The sale prices and terms of the system services and the criteria according to which they are determined shall be equitable and non-discriminatory to all system users. Exceptions to them may only be made on special grounds.

The pricing of system services shall be reasonable.

The pricing of system services must not present any unfounded terms or restrictions obviously limiting competition within the electricity trade. However, the pricing shall take account of any terms needed for reliable operation and efficiency of the electricity system as well as the costs and benefits arisen by the connection of an electricity generation installation to a system.

Furthermore, Section 15 stipulates on spot pricing:

The system operator shall, for its own part, create preconditions permitting the customer to conclude a contract on all system services with the system operator to whose system he is connected as subscriber.

The system operator shall, for its part, create preconditions permitting the customer to be granted the rights, in return for payment of the appropriate fees, to use from its connection point the electricity system of the entire country, foreign connections excluded (spot pricing).

Within a distribution system, the price of system services must not depend on where within the system operator's area of responsibility the customer is located geographically.

On demand, the Ministry can issue detailed regulations on the application of the principles of spot pricing.
Section 38 a of the Electricity Market Act states on the supervision of the system operator:

By its decision, the electricity market authority shall confirm the following terms of services and methods of pricing services before their take-up to be complied with by the system operator and the grid operator under the systems responsibility:

1. methods to determine the system operator’s return on its system operations and the fees charged for the transmission service during the surveillance period;
2. terms of the system operator’s transmission service;
3. terms and methods of the system operator’s connection service to determine the fees charged from the connection;
4. terms of the services under the systems responsibility of the grid operator subjected to the systems responsibility and methods to determine the fees charged from the services.

The confirmation decision shall be based on the criteria laid down in chapters 3, 4 and 6 a and in Regulation (EC) No 1228/2003 of the European Parliament and of the Council on conditions for access to the network for cross-border exchanges in electricity. The decision confirming the pricing methods can order on the following:

1. valuation principles of capital bound to system operations;
2. method of determining the approved return on the capital bound to system operations;
3. methods of determining the result of the system operations and the correction of the income statement and balance sheet required by them;
4. target encouraging improvement of the efficiency of the system operations and the method of determining it, as well as a the method to apply the target in pricing;
5. the method of determining the pricing structure, if the method of determination is necessary for providing access to the system or to implement an international obligation binding on Finland or if the method of determination is related to pricing of services under the systems responsibility.

The confirmation decision, which is applied to the methods referred to in subsection 1(1), is valid during a four-year surveillance period. If the system operator has started its operations while the surveillance period applied to other system operators has not yet run out, the confirmation decision referred to in paragraph 1 of subsection 1 is, however, valid until the end of this surveillance period. The other decisions referred to in subsection 1 remain in force until further notice or, for a special reason, during the period laid down in the decision.

In the Act, it is stated that “the decision confirming the pricing method can order on the method of determining the pricing structure”; however, this is not requested from the surveillance authority.

Section 1 of the Electricity Market Act states on energy efficiency that

Undertakings operating in the electricity market are responsible, for example, for providing their customers with services relating to the supply of electricity and for promoting electricity efficiency and conservation in their own business operations as well as in those of their customers.

However, unlike the directive 2006/32/EC, which states that there shall not be such incentives in transmission and distribution tariffs that unnecessarily increase the volume of distributed energy, the present legislation on the electricity market does not include any direct requirement on this kind. Currently, the regulatory model for the electricity distribution business monitors the reasonableness of the DSO’s return on capital, in addition to which limits are set on the amount of network asset depreciations and operative costs. Thus, in practice, the regulatory model sets the limits on the turnover of the DSOs, but does not take stance on the pricing structure.
The Act on energy efficiency services of enterprises operating in the energy market (1211/2009) stipulates an obligation for enterprises operating in the energy market to promote their customers’ electricity efficiency and conservation in their operations. The Act is applied to enterprises that sell or deliver electricity or district heating, district cooling or fuel. In practice, the Act sets requirements concerning electricity billing mainly for the electricity retailer; the act states that the retailer shall bill the electricity based on energy consumption at least three times a year. In addition, the retailer shall provide the end-user with a report of his/her energy consumption.

From the perspective of this research project, Chapter 6 of the Government Decree on determination of electricity supply and metering (66/2009)\(^1\) is of practical relevance, as it determines the minimum requirements for the metering of electricity supply:

Section 4:

*The metering of electricity consumption and small-scale electricity generation shall be based on hourly metering and remote reading of the metering equipment (obligation of hourly metering).*

Section 5:

*The hourly metering equipment installed at the site of electricity use and the distribution system operator’s information system processing the metering data shall have at least the following characteristics:*

1) *The data recorded by the metering equipment shall be remotely readable from the memory of the metering equipment through a data transmission network (remote reading feature);*

2) *The metering equipment shall record the starting and ending points of the de-energised periods the duration of which exceeds three minutes;*

3) *The metering equipment shall be capable of receiving and executing or forwarding load control commands sent through the data transmission network;*

4) *The metering data and the data concerning the de-energised periods shall be stored in the distribution system operator’s information system that handles the metering data; the hourly metering data shall be stored in this information system at least for six years and the data on the de-energised periods at least for two years;*

5) *The data protection of the metering equipment and of the distribution system operator’s information system handling the metering data shall be secured appropriately.*

*The distribution network operator must offer hourly metering equipment for the customer’s use, including a standardised connection for real-time monitoring of electricity consumption, if the customer places a separate order for such equipment.*

In addition, the decree lays down a transition period such that at least 80% of the consumption sites shall meet the above conditions by the end of 2013. Based on the legislation presented above, we may assume that in the future there will be meters in use that meter the hourly mean powers and are read once a day. This is the technical boundary condition applied also to the tariff alternatives considered in this report.

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\(^1\) Unofficial translation; the decree available only in Finnish and Swedish
Furthermore, according to Section 1 of Chapter 7 of the above-mentioned decree

*The distribution system operator shall offer metering services in accordance with the general time differentiation to the customers within its area of responsibility.*

*Metering services in accordance with the general time differentiation include:*

1) *metering service based on hourly metering;*

2) *metering service for a flat rate tariff;*

3) *metering service for a two-rate tariff (day/night);*

4) *metering service for a seasonal tariff (winter weekday and other energy).*

Thus, the decree obliges to offer the above-described metering services. In practice, the present distribution tariffs follow the above division of metering services; however, this division is not required of the distribution charges, but it applies only to the metering services.

The objective of the Energy Services Directive (2006/32/EC)\(^2\) and the energy efficiency agreements adopted in accordance with it is to reduce energy use from the level of 2001–2005 by 9 % by 2016. There is an energy services action plan for the enterprises operating in electricity transmission and distribution and district heating; 91 enterprises had joined the plan by 26 January 2012. A directive target of the energy sector is to take measures that lead to a 150 GWh saving of electricity in the electricity transmission and distribution losses and in the electricity consumption of generation and transmission of district heat, and a 150 GWh saving in distribution losses of district heat and fuel consumption in separate generation of heat by 2016 compared with the present level without the above measures. Again, the target of the companies that have joined the agreement is to reduce their energy use at least by 5 %. Furthermore, the target of the companies that have signed up to the agreement is, together with their customers, to implement measures that promote the efficiency of the energy end use, and thereby, reaching of the energy savings targets (Energy Efficiency Agreements). Hence, reduction of losses, which is achieved for instance by cutting of the peak powers, is vital also for reaching the energy efficiency targets.

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3 Current tariff schemes and their reform needs

The distribution tariffs of small-scale consumers in Finland typically comprise a fixed charge, which depends on the size of the main fuse, and an energy rate, which may vary between times of the day and seasons. Demand-based tariffs instead are intended for larger customers. Hence, the time dynamics of the small-scale consumer tariffs is mainly limited to the two-rate tariff, and the power taken at the connection point is limited only by the main fuse. Thus, the financial incentives for the temporal optimisation of electricity use are limited.

According to a survey by the Energy Market Authority (EMA 2010a), the proportion of the fixed charge in the tariffs has increased significantly over the past ten years, which for its part indicates needs for reforms in the tariff scheme. Table 3.1 and Figure 3.1 present the results of the survey considering the proportions of fixed and variable costs in the electricity distribution tariffs for typical end-users:

- K1, Flat, no electric sauna heater, main fuse 1 x 25 A, electricity consumption 2 000 kWh/yr
- K2, Detached house, no electric heating, electric sauna heater, main fuse 3 x 25 A, electricity consumption 5 000 kWh/yr
- L1, Detached house, direct electric heating, main fuse 3 x 25 A, electricity consumption 18 000 kWh/yr
- L2, Detached house, partly accumulating electric heating, main fuse 3 x 25 A, electricity consumption 20 000 kWh/yr
- T1, Small-scale industry, power demand 75 kW, electricity consumption 150 000 kWh/yr

The reference material in the survey comprises tariffs including VAT but excluding the electricity tax and the security-of-supply fee.

Table 3.1 Proportion of the fixed and variable tariff components in the distribution tariffs of different types of consumers in 2000 and 2010 (EMA 2010a).

<table>
<thead>
<tr>
<th>Type of consumer</th>
<th>Fixed 1/2000</th>
<th>Fixed 1/2010</th>
<th>Variable 1/2000</th>
<th>Variable 1/2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>K1</td>
<td>42.4 %</td>
<td>58.2 %</td>
<td>57.6 %</td>
<td>41.8 %</td>
</tr>
<tr>
<td>K2</td>
<td>31.1 %</td>
<td>43.4 %</td>
<td>68.9 %</td>
<td>56.6 %</td>
</tr>
<tr>
<td>L1</td>
<td>26.0 %</td>
<td>34.9 %</td>
<td>74.0 %</td>
<td>65.1 %</td>
</tr>
<tr>
<td>L2</td>
<td>28.6 %</td>
<td>34.9 %</td>
<td>71.4 %</td>
<td>65.1 %</td>
</tr>
<tr>
<td>T1</td>
<td>24.6 %</td>
<td>24.6 %</td>
<td>75.4 %</td>
<td>75.4 %</td>
</tr>
</tbody>
</table>
The above figure shows that the proportion of the fixed tariff component has increased for all types of consumers except for industrial customers. Increasing the proportion of the fixed tariff component enhances the predictability of the distribution revenues, because in addition to the changing trends in the electricity consumption habits, the volume of transmitted energy is significantly influenced by the outdoor temperature. The above results are based on data for 2010, and a similar tendency has continued ever since; that is, the proportion of the fixed tariff component has increased further.

However, the proportions of the variable and fixed tariff components vary between DSOs, as shown in Figure 3.2, which illustrates the standing charges and energy rates in typical flat rate distribution tariffs (for a 3x25 A main fuse) by DSOs based on statistics provided by the Energy Market Authority.

![Figure 3.1 Proportion of fixed charge in the distribution tariffs of different types of consumers (based on EMA 2010a).](image1)

![Figure 3.2 Flat rate distribution tariffs of Finnish distribution system operators for a main fuse of 3x25 A (based on statistics of the Energy Market Authority).](image2)
3.1 Incentives of the tariff scheme

In the present tariffs, the flat rate tariff consists of a fixed standing charge (€/month) and an energy rate (cent/kWh), which is constant regardless of the time of use. The fixed monthly charge is usually based on the size of the main fuse, which in itself promotes the optimal dimensioning of the connection point. In practice, the power is limited only by the size of the main fuse, which is most typically 3x25 A. The energy component, again, encourages reduction of the total consumption of energy; however, its proportion has decreased in the 2000s, as stated above, which has weakened the above-described incentive effect.

The two-rate tariff similarly comprises a fixed standing charge, which depends on the size of the main fuse, and an energy rate, which is lower in the night-time (usually from 10 p.m. to 7 a.m.). The incentive effects of this tariff are otherwise similar to the flat rate tariff, but the tariff also includes an incentive to schedule the electricity use to the night-time whenever possible. In practice, this tariff type is used in connection with accumulating electric heating. The target of the tariff is to balance loads by shifting the electricity use to the night-time, when electricity is typically used least. However, the control does not monitor the state and needs of the electric power system, but numerous boilers that are simultaneously switched on may cause problems both in the distribution system and in the national power balance.

Considering the present tariff schemes, we may state that they encourage reduction of energy use, although the proportion of the fixed component has increased over the years. However, there are hardly any incentives for the target that is most vital for the distribution system, that is, the reduction of peak power.

3.2 Cost reflectivity of the present tariffs

As shown in Chapter 2, a majority of the costs of a DSO are either fixed ones or depend on power, while only a minority depend on the volume of energy transmitted. Although the proportion of the fixed tariff component has increased, the energy-based tariff component still plays a key role in the revenue stream. Thus, the present tariffs do not correspond very well with the cost structure of DSOs. Moreover, in the present tariff scheme, the charges are not necessarily allocated to the customers by the matching principle, as will be illustrated below.
Figures 3.3 and 3.4 present an annual duration curve for two actual end-customers. Both the customers have a 3x25 A main use, and their billing is based on a two-rate time-of-day tariff.

As the network dimensioning is based on peak power, customer B produces a higher cost for the DSO than customer A. If the distribution pricing is based on transmitted energy, customer A will, however, pay a higher distribution charge than customer B. In other words, costs are not correctly allocated, but the customer producing a lower cost pays a higher distribution charge. If the proportions of fixed and variable tariff component are equal in the DSO’s tariffs, customer A will pay a distribution charge that is about one-quarter higher than the charge of customer B.
3.3 Change trends in electricity use

Significant changes have taken and will take place in the volume of transmitted energy and power demand, which have an impact on the revenue and costs of the DSOs. Figure 3.5 illustrates the effect of different actions on the power and energy as discussed in the workshop held in 2011. The workshop comprised researchers and representatives from DSOs and the Finnish Energy Industries, 22 persons altogether. Naturally, the effects are case specific, and thus, the figure only presents the experts’ average estimates of the direction and magnitude of these changes.

![Figure 3.5 Effects of different actions on the power and energy transmitted on the distribution network.](image)

The actions that reduce the volume of transmitted energy and either increase or only slightly decrease the power demand are most problematic with respect to the present tariff system, which is chiefly based on transmitted energy. In particular, heat pumps in buildings with electric heating and customers’ own electricity generation are problematic in this respect. For instance, it has been estimated that heat pumps will reduce the amount of annual transmitted energy by 11% by 2020 in the operating area of a single distribution system operator, while the peak powers remain unchanged. If the tariff scheme remained in its present form, this would reduce the annual turnover.
by 5 %, whereas this development would not have an impact on the costs of the DSO. In the scenario of the highest impact, the volume of energy transmitted would decrease by 25 %, which, in turn, would decrease the annual turnover by 12 % (Tuunanen 2009). Consequently, the revenues would not correspond with the costs, and thus, the unit prices would have to be raised if the present tariff scheme were kept in force. Here, it is worth pointing out that heat pumps, similarly as the other actions in the figure, improve energy efficiency, and their adoption should be encouraged.

In general, we may state that energy saving and promotion of energy efficiency are targets to the adoption of which the customers should be motivated. However, at the same time, with the current tariff scheme, these actions have a negative impact on the economy of the distribution system operator, and they make the tariff scheme less cost reflective. Thus, considering both the revenue stream and the incentive aspects of the tariffs, the present tariff schemes have to be developed to better correspond with the changing operating environment. In the next chapter, alternative tariff schemes are introduced.
4 Alternative tariff schemes

As shown above, the reform needs are evident in the present tariff scheme. In principle, the pricing of electricity distribution can be arranged in multiple ways. Bearing in mind the basic requirements for the tariff scheme, such as spot pricing, cost reflectivity and intelligibility, the alternatives are, in practice, narrowed down to a few schemes that can be applied either separately or combined. In the following sections, a few alternative tariff schemes are introduced, and their features are compared with the above-presented requirements and boundary conditions.

4.1 Fixed monthly charge

The principle of this tariff scheme is that the energy component is removed from the present tariff scheme, and thus, the tariff will only include a fixed monthly charge that is based on the size of the main fuse; the charge will of course be higher than the present one, as the turnover of the DSO is assumed to remain unchanged. For a customer, a distribution tariff of this kind is simple; for the DSO, the revenue stream is predictable, and, to some extent, cost reflective. The tariff would not produce contradictory incentives with the retail tariff, and would allow market-based demand response. Considering the network effects, the only incentive provided by the distribution tariff would be related to the optimisation of the main fuse size. However, the options are limited (for small-scale customers, typical alternatives are 3x25 A and 3x35 A). Thus, the peak power taken from the network is only limited by the main fuse, and the tariff does not include any other incentives for the optimisation of power consumption. Hence, only the retail tariff stimulates the efficiency of energy use.

A recent trend has been to increase the proportion of the fixed tariff component, as was stated above. An ultimate alternative of this development trend would be to have a fixed standing charge only, in which case the energy component would be removed altogether. Having only a fixed charge would thus guarantee predictable and stable transmission revenues for the DSO also in the changing operating environment. In a tariff scheme of this kind, the customers’ opportunities to affect their electricity bills are practically non-existent, and the tariff scheme would not encourage energy efficient consumption of electricity. Thus, we may conclude that a tariff structure comprising a fixed component only would not meet the above criteria.
4.2 Energy rate

A trend opposite to the previous one is the course of development from the present tariff scheme to a tariff component that is based solely on energy. However, in practice, the trend has been quite the opposite, which, for one, is an indicator of the problems of the energy-based pricing from the DSO’s perspective. As it was stated above, only a minority of the costs of the DSO depend on the volume of energy transmitted, and thus, the cost reflectivity of the energy-based tariff would be lower than that of the present tariff (fixed charge and energy component). In addition, the predictability of the DSO revenue would decrease significantly, as the transmission revenues are directly dependent on the volume of energy transmitted. In that case, the variation in the outdoor temperature would have a higher impact on the revenues than at present.

An energy-based distribution tariff would strongly encourage the end-customers to reduce their energy consumption, which is naturally further supported by the electricity retail tariff. However, an energy-based tariff does not include any incentives to reduce the peak power, and thus, a reduction in energy consumption does not necessarily decrease the costs of the DSO. Consequently, we may state that the incentive effects or the cost reflectivity of the distribution tariff based solely on energy are not as good as anticipated.

4.3 Dynamic energy tariff

A development option that would encourage the customers to optimise their energy consumption into a direction that is optimal from the viewpoint of the distribution system is a dynamic energy tariff, in which the price of transmitted energy (cent/kWh) would vary according to the time of use. At present, a similar model is found in the two-rate tariff, where the energy rate is lower in the night-time. In this case, however, there are only two time and price levels in use, although the number of levels can, in principle, be significantly higher. When in the near future all the end-customers will have remotely read meters, the energy distribution charge could vary more dynamically according to the time of use, as illustrated in the simplified example in Figure 4.1.
In this tariff model, the price could be stepped so that the price would be highest at the instants when the network load is at highest, and vice versa. The time steps could be constant for every day, and differentiated between weekdays, Saturdays and Sundays, or they could vary so that the prices would be given in advance for instance on the previous day.

In a tariff structure of this kind, however, problems could arise both for the customers and the distribution system operator. First, the load behaviour varies significantly between different customers; the load peaks of domestic customers occur in the evening, while at workplaces the electricity consumption is highest during the working hours. Thus, the time structure of a pricing scheme that would effectively balance the loads on the network should be based either on a single feeder or even on the supply area of a single distribution transformer. This would lead to different prices in different supply areas of the DSO, which is unambiguously prohibited by the Electricity Market Act. Using several price steps, together with a possible variation of inexpensive and expensive hours, would make the system complicated for the customers. Moreover, the tariff structure could produce contradictory incentives between the electricity retail and distribution, if the expensive and inexpensive hours for the distribution charge and the market price occurred at different times. In that case, the market-based demand response and the pricing of electricity distribution would steer the consumption in opposite directions. The suggested tariff structure would become too complicated, and its incentive effects would be ambiguous for the customer. For a DSO, it would also be uncertain whether the targets set for the tariff scheme could be met.
4.4 Power-based pricing scheme

In the power-based pricing, the distribution charge is based on the peak power taken from the grid (in practice, the highest hourly mean power) over a certain time period, or on a certain subscribed capacity agreed upon with the DSO. Power-based pricing is nowadays common for large-scale customers, whereas it is not used for small-scale customers. In Sweden, for instance Sollentuna Energi has introduced power-based pricing for all of its customers. In Sollentuna’s network tariffs, there are a standing charge that depends on the main fuse size (e.g. 1 200 Swedish kronor/a for a 25 A fuse without taxes) and power charge (from November to February 69.60 kronor/kW, month and from April to October 34.80 kronor/kW, month excluding taxes). The power charged to the customer is based on hourly powers on weekdays between 7 a.m. and 7 p.m., from which a mean value of three peak hourly powers is calculated on a monthly basis (www.sollentunaenergi.se).

In practice, the power tariff is cost reflective for the DSO, because the pricing principle is the same as the key cost basis of the electricity distribution. Also the predictability of transmission revenues is higher than in the energy-based pricing, as for instance the variations in the annual mean temperature have a significantly lower impact on the annual peak powers than on the volume of transmitted energy. Similarly, the structural changes in the electricity end-use, such as installation of a heat pump for space heating, have a lower effect on power than on energy.

The suggested pricing scheme would steer the customers to reduce their peak powers, which would promote the energy efficiency of electricity distribution. Reduction in the overall energy consumption is encouraged by the energy rate of the retail tariff as well as by the electricity tax, and also the distribution charge may involve an energy component in addition to the power component. This, however, complicates the tariff scheme further. In principle, the price of power may vary by the time of use, either so that the powers at low-load hours are not taken into account when determining the peak power used as the pricing basis, or so that the price of the peak power occurring at the peak load hour is higher. This, however, may lead to similar problems as described above for the dynamic energy tariff. The basis for pricing can be either active power (kW) or current (A). The benefit of the latter is that it also includes reactive power, but on the other hand, the power demand is usually given in watts in electric devices, and it is thus easier to understand as a unit of measurement. In practice, in power-based pricing, the customers should be able to follow and limit their power demand, either manually or automatically, for instance by alternation. Power-
based pricing may involve different pricing models; these are for instance sliding power pricing and power band pricing, which are introduced and discussed in the following.

In the sliding power pricing, the customer could be charged for instance according to the highest metered hourly mean power of one year based on the AMR data. The hourly powers applied to the customer billing would be metered for a period of one year. The bill would be the same for every month for a year. For instance, a household with the highest hourly power of 10.0 kW would pay a distribution charge of 50 €, if the kW price were 5 €. The annual distribution charge would thus be 600 €. Variation could occur in the distribution charges in the sliding power pricing scheme between years, even though the amount of variation is lower in power than in energy. Nevertheless, the variation in annual power would degrade the predictability of the DSO’s turnover. In particular, fluctuations in the power demand of customers with electric heating can be quite significant. The highest hourly power of a customer with electric heating may vary by more than 3 kW between years. Based on the customers’ hourly metering data over the few past years, the values between years may vary by 2 kW even for the 30th highest hourly power for a customer. Now, we assume that the DSO has decided to determine the kW price to be 5 € in this pricing scheme, and the basis of charging is the mean value for the 30th highest hourly power. If there is a 2 kW difference between two years in the charging of hours used in the calculation, this will mean 2kW x 5 €/kW, month x 12 months = 120 €, year in the DSO’s turnover and the customer’s distribution bill.

Variation may thus take place between years, which is not desirable either for the distribution system operator or the customer. Figure 4.2 shows DSOs’ total variations in power between years.
Another power-based alternative is a power band pricing scheme based on current or power. For a DSO, a benefit of power band pricing is the same power band and power band charge for the whole year and an almost constant turnover in different years. Power band pricing is discussed in more detail in the following chapter.
5 Power band

Power band is a distribution pricing scheme developed from power-based pricing. It seems a viable novel solution to distribution pricing, and therefore, it has been studied in a larger scale. For customers, DSOs and the electricity market as a whole, power band pricing involves various positive features. For instance, a power band would promote, better than the sliding power pricing scheme, the targets of a distribution network turnover that would be steady at an annual level and the equal monthly distribution charges of customers. Introduction of power band pricing would not require any new technology or large investments. The ongoing installation of remotely read electricity meters, however, has to be accomplished prior to the transfer to this pricing scheme. A further benefit of the power band is the low dependency of distribution charges on the outdoor temperature. This, again, has an influence on the turnover of the DSO and the distribution charges of customers with electric heating. The AMR meters in smart grids together with various control systems may enable new functionalities in the electric power systems, but also produce new development needs in distribution pricing. In this respect, the power band could be a viable alternative because it is flexible and cost reflective.

5.1 Introduction of power band

The concept of power band is familiar to the public through internet broadband. In the context of electricity distribution, the concept would mean that a customer would subscribe to the desired subscribed power, in other words, electricity distribution capacity, provided by the DSO. In practice, this would correspond to the practice of subscribing to a broadband service of a mobile operator. In distribution pricing, the transition to the power band pricing could thus make the customer’s electricity bill more intelligible. However, the intelligibility of power band pricing is not addressed in more detail in this study, and thus, the issue should be studied further in the future.

The customers’ subscribed power could chiefly be the transmission capacity required by the customer, that is, the mean power of the peak hour. Considering the electricity distribution capacity, some other options have been studied in addition to the highest hourly mean power; however, it has been found to be clearly the best one for the purpose. The price of subscribed power would be determined based on the network operation costs, that is, the regulated revenues and volumes of subscribed power. Power-based pricing would encourage the customers to reduce their subscribed
power, and thus, the loads could be balanced more evenly. If the pricing were based on power, the customers would pay for the proportion of the total network capacity they have used. The average network tariffs of customers would not change; in other words, the revenues of the DSO would remain constant in the new situation. Similarly, the average proportion of the distribution fee in the total price of electricity would remain unchanged.

A customer’s power band would be determined based on the highest metered hourly mean power of the year; in other words, in practice according to the customer’s hourly peak power. For instance, for the customer in Figure 5.1, the highest hourly power would be about 14 kW. If the customer were charged based on the highest hourly power, the customer’s power band would be 14 kW. The customer would pay a fixed monthly charge for the power band every month of the year.

In principle, we may think that a customer is already billed based on a power band scheme. The fixed charge in the DSO’s distribution tariff is usually based on the customer’s main fuse size. The domestic customer in Figure 5.1 has a main fuse of 3x25 A, and thus, the largest power band measured as an hourly power would be approx. 17 kW (indicated by the red line in the figure). The customer could consume a significantly larger amount of electricity in an hour, that is, for the whole band width with the same standing charge; however, the proportion of the energy rate in the retail and distribution tariffs and the electricity tax would limit the excessive use of energy. Now, the fuse size is the only factor that limits the peak power; yet, for small-scale customers, it has almost no incentive to reduce power consumption.

Figure 5.1 Hourly AMR metering data of a domestic customer for 2011. The customer has a main fuse of 3x25 A and a flat rate electricity tariff in use. The customer’s highest hourly power is approx. 14 kW. The customer could use the whole power band of 17 kW limited by the main fuses (red line) with the present standing charge.
Hence, the present distribution pricing does not encourage reduction of power demand. The customer does not have an opportunity to affect the standing charge either, if the main fuse size of the customer is already as small as it can be. Despite this, the customers should have an incentive to reduce their peak power and thus affect the standing charge.

A fixed monthly charge may sometimes be somewhat challenging from the pricing point of view. Exceptional distribution pricing, for instance temporary electricity supply, may cause slight ambiguity in pricing. In power band pricing, this could be solved for instance by multiplying the annual distribution charge for a certain power band by the ratio of the days when temporary electricity supply is needed to the days of one year (365).

5.2 Pricing schemes and the unit of power band

A suitable pricing scheme that is in compliance with the laws and directives set for pricing should be established for the power band. Moreover, it should be applicable to different distribution system operators and customer types. In Finland, there are a large number of DSOs, and the pricing schemes and prices vary considerably between the operators. On the other hand, the networks of DSOs are very different, and thus, the distribution prices should not be compared between the companies.

In addition to the different operating environments of the DSOs, the customer distribution and the electric energy and power consumed by the customers vary significantly. This can be illustrated by the flat rate distribution tariff that almost all DSOs offer for their customers. In the flat rate electricity tariff alone there are usually different categories for the main fuse size, such as 3x25 A or 3x63 A, into which the customer may fall. In addition to this, the same flat rate distribution tariff group may include customers that live in blocks of flats and have low energy consumption, or small-scale industrial customers with a larger consumption of electricity. Hence, there is a significant amount of variation, which has to be taken into account when analysing the calculation results. If the issue is considered with respect to customers of a certain type, we will understand the reasons for this variation. Table 5.1 shows the differences between individual customers within a customer group of similar type.
Table 5.1 Annual energies, peak powers and annual distribution charges according to the prevailing pricing scheme as well as the peak operating time for different customers living in detached houses (DH) with electric heating.

<table>
<thead>
<tr>
<th>Customer type</th>
<th>Annual energy [kWh]</th>
<th>Peak power [kW]</th>
<th>Present distribution charge [€, a]</th>
<th>Peak operating time [h]</th>
</tr>
</thead>
<tbody>
<tr>
<td>DH electric heating</td>
<td>6 834</td>
<td>3.56</td>
<td>472</td>
<td>1920</td>
</tr>
<tr>
<td>DH electric heating</td>
<td>10 339</td>
<td>4.63</td>
<td>515</td>
<td>2233</td>
</tr>
<tr>
<td>DH electric heating</td>
<td>11 586</td>
<td>8.71</td>
<td>502</td>
<td>1330</td>
</tr>
<tr>
<td>DH electric heating</td>
<td>11 789</td>
<td>4.12</td>
<td>533</td>
<td>2861</td>
</tr>
<tr>
<td>DH electric heating</td>
<td>12 130</td>
<td>8.43</td>
<td>475</td>
<td>1439</td>
</tr>
<tr>
<td>DH electric heating</td>
<td>12 197</td>
<td>6.06</td>
<td>509</td>
<td>2013</td>
</tr>
<tr>
<td>DH electric heating</td>
<td>14 810</td>
<td>9.07</td>
<td>653</td>
<td>1633</td>
</tr>
<tr>
<td>DH electric heating</td>
<td>15 061</td>
<td>7.83</td>
<td>551</td>
<td>1923</td>
</tr>
<tr>
<td>DH electric heating</td>
<td>16 534</td>
<td>7.51</td>
<td>678</td>
<td>2202</td>
</tr>
<tr>
<td>DH electric heating</td>
<td>16 923</td>
<td>7.30</td>
<td>702</td>
<td>2253</td>
</tr>
<tr>
<td>DH electric heating</td>
<td>17 094</td>
<td>7.82</td>
<td>821</td>
<td>2186</td>
</tr>
<tr>
<td>DH electric heating</td>
<td>20 712</td>
<td>10.77</td>
<td>693</td>
<td>1923</td>
</tr>
<tr>
<td>DH electric heating</td>
<td>24 467</td>
<td>9.43</td>
<td>907</td>
<td>2595</td>
</tr>
</tbody>
</table>

In the example group, the customers live in detached houses (DH) with electric heating (either accumulating, partly accumulating or direct electric heating). The table gives the electric energy consumption of one year, the peak power and the annual distribution charge according to the present pricing scheme and the peak operating time for these customers. There are 13 customers in the group, and their annual energies vary between 6.8 and 24.4 MWh. As we can see, the customers’ annual consumption may vary considerably even among customers of similar type. The differences in annual energies are explained by different types of heating. Some customers have electric heating only, while some may have additional heating with wood or a heat pump. In addition, also the size of the building has an impact on the demand for heating. All the customers are charged at a two-rate time-of-use tariff. The differences in distribution charges are revealed by the energy consumption over time. For instance, the amount of distribution charge paid by the first customer is almost the same as that of the second customer, although he/she consumes 3.5 MWh less. The difference is explained by the fact that the consumption of the first customer takes place mainly in daytime when the price of energy is at highest and vice versa. In addition, Table 5.1 illustrates the differences in the measured highest hourly mean powers between the customers. For
instance, the peak power of the last customer is less than 10 kW, although he/she consumes less energy and pays a higher distribution charge than the second last customer, the peak power of which is more than 10 kW.

There are various alternatives available both for the distribution and power band pricing. The unit price may behave in different ways with respect to kW or amperes. Alternatives for power band prices could be for instance a unit price that decreases with the increasing power band, fixed price and increasing price. In addition to these, various step schemes can be developed for the power band, where the steps occur for instance at every ampere or 5 kW. In the power band scheme, suitable steps should be found for each band so that the monthly charge still increases as the band increases. This condition has to be met to ensure that customers have motivation to reduce their power band. On the other hand, the pricing scheme should not encourage the customers to subscribe to larger power bands, in which case they would not pursue the aim of reducing their power. Thus, a decreasing unit price is out of question. Alternatively, if the unit price were increasing along with an increasing band, the high band prices for large power bands would cause a problem. Hence, we may conclude that it is justified to apply a fixed price as the price for the power band. Consequently, the price would be equal to all customers and encourage power saving. In addition, there would be a clear basis for the power band pricing and power optimisation of the customer power.

In most of the Finnish DSOs, the standing charge in the distribution pricing depends on the size of the main fuse; on the charge scale, the lowest standing charges are either for 1x25, 3x25 A or 3x35 A. Compared with the present distribution pricing, the steps in the power band pricing scheme should be significantly smaller. Quite a different approach is provided by an alternative where the bands occur in steps of one ampere. For a DSO, the transition from the present charge scale to a fine power band scale would be difficult and rigid to implement. In addition, the customers should have suitable devices to be able to meter their consumption on the fine power band scale. These would include at least a consumption display, home automation system or an online service provided by the DSO. Such devices, however, are possessed only by few customers. Thus, it is advisable to first define the steps for more than one unit, such as five units on the power band scale.

Yet another issue related to power-based pricing is whether the unit of pricing is amperes or kilowatts. Ampere is the unit of current, and amperes are familiar to customers because of the main fuse size applied in the present distribution pricing. Amperes would be practical and easy to use, as they would remove the need to charge for reactive power. If amperes were applied, the DSOs would
have to modify their AMR data, which is given in kilowatts. On the other hand, amperes may be difficult for the customers to understand; it may be challenging to explain to a customer how one ampere (of consumption) is formed or how large an ‘ampere band’ the customer needs. In the case of kilowatts, this is easier as power ratings are usually given in different electric devices. Thus, the customers are able to consider their power consumption and requirements for the power band. For instance, a customer living in a flat may have a 6 kW electric sauna heater. The customer is probably able to comprehend that this is the minimum amount of power band he/she needs. At the same time, the efficiency of different electricity saving measures is clarified. For instance, if the customer has a device with a power of 2 kW, and he/she decides to invest in a new, similar device with a power of 1 kW, he/she probably understands the effect of the investment on the price of electricity distribution. A slight problem in the application of kilowatts is the separation of effective and reactive power. In the power-based pricing, the DSOs would like to apply separate pricing for active and reactive power; in particular, as the amount of reactive power is currently increasing for instance because of the increasing number of energy saving lamps. Nevertheless, for the customers, separate charges for active and reactive powers would be difficult to comprehend. In the kilowatt-based pricing scheme, the active and reactive power could be combined (apparent power), and the charging would be unified, comprising both price components. On the other hand, it is worth remembering that the present remote meters installed at customers are not typically able to meter active and reactive power separately, or amperes. Thus, it is justified to use kilowatts as the unit of pricing, and reactive power pricing is omitted from the considerations for the time being. However, the issue of reactive power should be addressed in more detail in the future studies.

The applicability of the power band scheme could be evaluated by considering the present distribution pricing scheme based on the size of the main fuse. If the issue is approached from the perspective of power band pricing, the domestic customers will nearly always order a power band of 17 kW; the customers have no opportunity to affect this. Let us take a different approach and provide the customers with an opportunity to scale their power band down. Based on the above, it has been decided to apply kilowatts with a 5 kW power band scale as a basis for the power-based pricing in the calculations. In Table 5.2, two different alternatives are given to show how the main fuses and their powers would correspond to the power band scale. On the left, there is a power band scale with 5 kW steps, and on the right with 3 kW steps. In principle, both the scales are correspond well to the present main fuse sizes and thereby also to the standing charges. In Table 5.2 on the right, the scale starts from 2 kW, which can be too low even for the smallest consumers. If the target
is to use a fixed price as the unit price, a threshold charge should be included in the pricing. This threshold charge would be a minimum distribution charge to cover the fixed costs.

Table 5.2 Alternative power band scales. The left-hand column has been used in the calculations. The right-hand column is based on the idea of determining the power bands in smaller steps.

<table>
<thead>
<tr>
<th>Main fuse (A)</th>
<th>Power (kW)</th>
<th>Band (kW)</th>
<th>Main fuse (A)</th>
<th>Power (kW)</th>
<th>Band (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>2</td>
<td></td>
<td>2</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>5</td>
<td></td>
<td>8</td>
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</tr>
<tr>
<td>25</td>
<td>17</td>
<td>15</td>
<td>20</td>
<td>11</td>
<td>14</td>
</tr>
<tr>
<td>35</td>
<td>25</td>
<td>25</td>
<td>25</td>
<td>17</td>
<td>17</td>
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<tr>
<td>50</td>
<td>35</td>
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<tr>
<td>63</td>
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<td>45</td>
<td>25</td>
<td>29</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>35</td>
<td>32</td>
<td></td>
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<td></td>
<td></td>
<td>35</td>
<td>38</td>
<td></td>
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<td></td>
<td>41</td>
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<td></td>
<td></td>
<td></td>
<td>63</td>
<td>44</td>
<td>43</td>
</tr>
</tbody>
</table>

It is difficult to determine a fixed price for the pricing of the power band, if the smallest band of the customer is really small. Therefore, a threshold charge is required, if the target is to collect a certain minimum sum to cover the fixed costs caused by the customer. Table 5.3 lists the monthly and annual charges on a finer power band scale where the unit price is a fixed price of 2.5 €/kW, month.
Table 5.3 Example of monthly and annual prices for power bands. The unit price €/kW is an approximate value.

<table>
<thead>
<tr>
<th>BAND (kW)</th>
<th>PRICE (€/kW)</th>
<th>PRICE (€, month)</th>
<th>PRICE (€, a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>2.5</td>
<td>5</td>
<td>60</td>
</tr>
<tr>
<td>5</td>
<td>2.5</td>
<td>12.5</td>
<td>150</td>
</tr>
<tr>
<td>8</td>
<td>2.5</td>
<td>20</td>
<td>240</td>
</tr>
<tr>
<td>11</td>
<td>2.5</td>
<td>27.5</td>
<td>330</td>
</tr>
<tr>
<td>14</td>
<td>2.5</td>
<td>35</td>
<td>420</td>
</tr>
<tr>
<td>17</td>
<td>2.5</td>
<td>42.5</td>
<td>510</td>
</tr>
<tr>
<td>20</td>
<td>2.5</td>
<td>50</td>
<td>600</td>
</tr>
<tr>
<td>23</td>
<td>2.5</td>
<td>57.5</td>
<td>690</td>
</tr>
<tr>
<td>26</td>
<td>2.5</td>
<td>65</td>
<td>780</td>
</tr>
<tr>
<td>29</td>
<td>2.5</td>
<td>72.5</td>
<td>870</td>
</tr>
<tr>
<td>32</td>
<td>2.5</td>
<td>80</td>
<td>960</td>
</tr>
<tr>
<td>35</td>
<td>2.5</td>
<td>87.5</td>
<td>1050</td>
</tr>
<tr>
<td>38</td>
<td>2.5</td>
<td>95</td>
<td>1140</td>
</tr>
<tr>
<td>41</td>
<td>2.5</td>
<td>102.5</td>
<td>1230</td>
</tr>
<tr>
<td>44</td>
<td>2.5</td>
<td>110</td>
<td>1320</td>
</tr>
<tr>
<td>47</td>
<td>2.5</td>
<td>117.5</td>
<td>1410</td>
</tr>
<tr>
<td>50</td>
<td>2.5</td>
<td>125</td>
<td>1500</td>
</tr>
</tbody>
</table>

The bands would continue by the same logic as far as required by the customers. Changes caused by the pricing scheme to the distribution pricing are calculated in steps of 5 kW. In the power band pricing scheme, the target is to improve the characteristics related to the distribution pricing, and thus, the purpose of the power band is not to impact on the construction of customer connections. Hence, the cross-sectional areas of low-voltage conductors and fuse sizes would remain unchanged. In other words, the size of a customer’s main fuse, e.g. 3x25 A, will not be scaled down, even if the customer subscribes to a power band of 10 kW. However, if the powers transmitted on the network decrease, also the long-term investment costs of the DSO will decrease, which will show in the distribution prices in the long term.

The calculations showed that the power band should first be introduced to replace the present standing charges. In that case, the tariff scheme will be similar to the present one (€/month + cent/kWh), but the standing charge would be determined based on the power band, and thus, a customer would have an incentive to reduce his/her power, and thereby a genuine opportunity to affect the amount of the standing charge. If the transition to the new pricing scheme were carried out this way, the non-recurring changes in the distribution price would remain minor. The transition to this pricing scheme could be carried out in one year’s time. Later, if the target is to increase the proportion of the power band in the distribution tariff, the proportion of the energy rate could be
reduced and the proportion of the power band could be increased. It will take time to ensure that the changes are not too radical for an individual customer. The schedule for this phase could be approximately five years.

5.3 Excess usage of power band

Opinions vary on how the power band size of an individual customer should be determined. We may question whether the highest hourly power is an equitable basis for the determination of the power band, and whether a customer can be allowed to exceed his/her band a few times without additional costs. For the DSO, using the highest hourly power as a basis for the determination would be justified, as the dimensioning of the network is based on the highest powers on the network. From the customer’s point of view, the highest consumed hourly power could also be a suitable basis for charging, as it would be based on actual consumption. A drawback is that the pricing scheme would be somewhat rigid. Considering the pricing, a more flexible option is that the customer is allowed to exceed the band for instance ten times. There are 8760 hours in a year, and hence, the tenth highest hourly power accounts only for 0.1 % of all the hours of the year. Events of excess usage of the power band are not very harmful to the network, as there is usually some flexibility involved in the present networks. From the customers’ perspective and for the sake of flexibility of the power band pricing, it would be justified to allow a customer to exceed the band for instance 10, 30 or even 50 times a year.

At the moment, the customers’ highest hourly power usually remains below the powers determined by the fuses. Sometimes the hourly powers may be somewhat higher than the powers limited by the fuses, because the fuses do not react to slight exceeding of the power limits. In the power band pricing scheme, significant exceeding of the power bands should not be possible, as the size of the main fuse should limit the customer’s band in any case. For instance, a domestic customer’s normal main fuse size is 3x25 A, which corresponds to 17 kW. Thus, in principle, the largest band that the customer could choose would be 17 kW. However, the powers above this would be limited by the fuses already. In addition, there are customers who, in principle, do not have an opportunity to choose too large power bands for themselves; such are for instance customers living in flats without an electric sauna. At customers of this kind, the largest current-using device is typically an electric stove, the power rating of which is usually about 3 kW. If we assume all other electric equipment to operate at the same time, the highest power still remains well below 10 kW.
On the other hand, a customer may also possess equipment that consumes a considerable amount of electric power compared with other devices. In that case, the customer may exceed the band without noticing when using all the electric equipment in an energy-inefficient manner at the same time. For domestic customers, a typical example is a sauna heater in a flat. However, excess usage events of this kind are not frequent, and they are usually minor. Thus, when changing over to power band pricing, significant exceedings of the power band will not take place, and the excess usage can be controlled somehow in practice. Obviously, the excess usage of the power band has to be observed.

In this context, in addition to the excess usage of the power band, it is worth our while to discuss the overdimensioning of power bands in brief. Overdimensioning of the power band would mean that a customer’s actual consumption would be clearly below the subscribed power band, in which case the customer could well do with a smaller band. A customer, the power band of which is based on 6.9 kW (highest hourly mean power) serves here as an example: the customer could do well with a 10 kW band, but pays for a band of 15 kW instead. Naturally, situations of this kind should be avoided. If the customer showed no interest in monitoring the size of his/her power band, the DSO could take care of the problems related to overdimensioning. In a situation like this, the information systems of the DSO would handle the situation. By monitoring the hourly power used as the basis for billing, the information system could detect that the customer can do well with a band of 10 kW. In that case, the DSO would automatically scale the customer’s band down. Thus, no harm would be done because of the oversized power bands. The same practice could be applied also to the selection of the power band in general: the DSO determines the power band, but the customer may change it and order another one. If the customer wants to have a smaller power band, he/she should have to pay for this. Subscribing to a larger power band instead would not cause extra costs. Changing over to a smaller band should be charged in order to prevent speculation on the band size and charges.

Let us return to the principles for determining the size of the power band. Based on the flexibility of the power band, we may consider that the customer’s power band could be determined for instance based on the 10th highest hourly power. An advantage would be that the number of events of excess power band usage could, in principle, be estimated for a customer in advance. If some flexibility is included in the determination of the highest hourly power, the customer pricing could also be based on the mean value of the highest hours. The calculations have shown that the issue is of no significance to a customer group. Similarly, for an individual customer, the differences between these two methods are quite marginal. Thus, the question of whether the basis for billing is for
instance the 30\textsuperscript{th} highest hourly power or its mean value is relevant only for a marginal number of customers. In addition, for the DSOs, the method based on the mean value of the highest hourly powers would probably be more difficult to implement. The mean value does not bring any additional benefit, and it is thus excluded from the considerations.

Larger differences may occur between individual customers depending on whether the customer’s band size is determined based on the highest hourly power or the 30th highest hourly power. The highest hourly powers of a customer may be a few kilowatts higher than the customer’s other consumption in normal conditions (see Fig. 5.3). This may partly be explained by the fact that in the distribution pricing products there have been no incentives steering the customers’ power consumption so far. In practice, the customers could have used their power capacity however they like within the limits set by their main fuses. Hence, it is likely that if the distribution pricing were based, if only partly, on the power consumed by the customers, the customers would start to pay more attention to their electricity consumption, and try to reduce their power use. The calculations seem to indicate that in our case, it is not very significant for the customer group whether the basis of billing is the hourly powers from the 30th highest power onwards; in other words, whether the basis of power band determination is the 30\textsuperscript{th} or 50\textsuperscript{th} highest hourly power. Changes may naturally take place, but they are usually such that one customer benefits from the change in the pricing scheme while another loses an equal amount. Thus, the basis for the determination of the power band is limited so that the highest hourly power is applied to determine the customer’s power band, and some events of excess power band usage are allowed.

\textbf{5.3.1 Events of power band excess usage; power band pricing in the standing charge only}

Applying the power band to the present standing charge may cause changes in the amount of the distribution charge for certain individual customers, and the distribution charge may increase for some customers in the transition period. However, it should be borne in mind that almost all customers will have an opportunity to change their power band to a smaller one and thereby affect their distribution charge. Therefore, when preparing the pricing scheme, special attention should be paid to the excess usage of the power band. If the power band were first applied to the standing charge only, the weight of excess usage would not have to be as high as when the power band forms the basis for the whole distribution pricing. The calculations have shown that in most cases, when
comparing a suitable practice for the excess usage between customers, it occurs that the price sinks for one customer but rises for another.

First, when switching from the present distribution pricing scheme to the power band scheme in the standing charge, the determination of the power band could be based on the customer’s highest metered hourly power of one year. This can be justified for instance by the fact that this would guarantee equal treatment of customers from the start. Another argument is that the practice applied to the excess power band usage would be unambiguous, which is probably highly important in the transition. If the charging is based on the highest hourly power of the previous year, it is likely that the number of events of excess power band usage is relatively low. This is illustrated by Figures 5.2 and 5.3, which present the consumption curves for different years.

![Customer with a flat rate tariff and a 3x25 A main fuse](image)

Figure 5.2 Hourly AMR data of a domestic customer for approx. one year (2006). The main fuse is 3x25 A, and the customer is charged based on the flat rate distribution tariff. The highest hourly power is slightly above 15 kW.

In Figure 5.2, the customer’s peak hourly power is about 15.5 kW, and thus, he/she should order a power band of 20 kW. The figure shows that there is no danger of exceeding the 20 kW band, and even if the band were 15 kW, exceeding of the band would be highly unlikely. However, the customer would have significant potential to cut the highest hourly power. In cases like this, the customer could nevertheless be provided with an opportunity to affect the size of the power band. The customer could check the size of his/her suitable power band for instance in an online service.
Figure 5.3 Hourly AMR data of the domestic customer of Fig. 5.2, now for year 2007. The highest hourly power is slightly above 12 kW. The customer’s 10th highest hourly power is also above 10 kW, and thus, the power band of 15 kW would still hold.

If the customer’s power band were determined according to year 2007, (Figure 5.3), his/her power band would be 15 kW based on the highest hourly power. No events of excess usage would probably occur in this case either. Instead, if the power band had been 10 kW, there would have been 15 events of excess usage. By cutting down his/her power consumption, the customer could well do with a 10 kW band.

The proportion of the standing charge is generally 10–60 % of the distribution charge. If power band pricing were applied only to the standing charge of the distribution charge and its proportion of the distribution charge were at least 50 %, the highest hourly power could be used as the basis in the determination of the power band. Customers at all power band steps should be allowed to exceed the band. The number of excess usage events could be same for all power band steps. A suitable number could be for instance ten excess usage events.

For the DSO, an advantage in changing over from the standing charge to the power band scheme is that it causes no risk to the company revenue. The DSO can control the revenue to be collected by determining the power band prices according to its targets. On the other hand, if the distribution pricing as a whole is based on power band pricing, the amount of power used in billing has to be reconsidered.
5.3.2 Excess power band usage; full power-band-based distribution pricing

If the distribution pricing were based fully on the power band and the highest hourly power consumed, it would cause significant changes in the electricity price to farmers, enterprises and small-scale industry. Let us consider an example of an agricultural consumer (farm) with main fuses of 3x63 A, corresponding to a power of 43 kW. The consumption curve of a customer of this kind is illustrated in Figure 5.4. The customer’s peak power is 33 kW and the customer has consumed 16.3 MWh of electricity during one year. Now, if the customer were charged according to the peak hourly power for the whole year, as it was assumed previously, the customer’s electricity bill would increase considerably from the present level. At the moment, the customer’s distribution charge is about 1 250 € without electricity tax, where the proportion of the standing charge is about 700 € and the energy rate is about 550 €. If the power band replaced only the standing charge in the distribution pricing, the customer’s distribution charge would remain at the 35 kW band nearly the same as with the present pricing scheme.

![Farm with a 3x63 A main fuse](image)

Figure 5.4 Electricity consumption of an agricultural customer, showing a peak caused by grain drying in July–August compared with the normal consumption rates. In the figure, one month equals 730 hours.

However, problems would arise if the proportion of energy rate were decreased and the proportion of power band were increased. In that case, the power band prices should be increased equally for all bands. As a result, the example customer’s price of the power band would be 2.5-fold; in other words, the agricultural customer’s new distribution charge would be about 3 150 € a year. Thus, the events of excess power band usage should be treated differently in the case of a full-weight power band than when the power band is applied to the standing charge of the electricity distribution. The
number of excess usage events should be taken into account, because the price of the power band would have a significantly higher weight in the price of electricity distribution.

For the example customer, a suitable power band would be 15 kW at the moment, when the period of grain drying in August is excluded from the analysis. With the power band pricing model, the customer’s distribution charge would be approx. 1000 €, in other words, it would be slightly lower than with the present pricing scheme. However, the events of excess power band usage cannot be neglected; if the customer had a 20 kW band, he/she would have exceeded it almost hundred times. As stated above, choosing a larger band for the customer is out of question, and thus, other solutions have to be sought. Here, we have at least two alternatives: either to allow the customer to exceed the power bands by different steps for the excess usage, or to charge the customer for the excess usage.

An example of the steps for the events of excess power band usage is given in Table 5.4. The figures in the table indicate for instance that a customer with a 5 kW band would be allowed to exceed the subscribed band ten times. The events would be recorded automatically by the DSO, and the customer would not have to worry about them. In addition, this method would help in tracking exceptional customers from the customer group.

Table 5.4 Example of the steps for events of excess power band usage. The figures are examples only.

<table>
<thead>
<tr>
<th>POWER BAND (kW)</th>
<th>NUMBER OF EVENTS OF EXCESS POWER BAND USAGE</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>10</td>
</tr>
<tr>
<td>10</td>
<td>20</td>
</tr>
<tr>
<td>15</td>
<td>30</td>
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<tr>
<td>20</td>
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<tr>
<td>25</td>
<td>75</td>
</tr>
<tr>
<td>30</td>
<td>100</td>
</tr>
</tbody>
</table>

Another alternative to track the exceptional customers would be to monitor the peak hourly powers of non-domestic customers monthly for a period of one year; in practice, this applies to customers in agriculture, small-scale industries and services. In other words, the customer’s highest hourly powers would be monitored monthly. It is typical for customers of this kind that the hourly powers remain relatively constant at an annual level. For instance, a customer’s powers could be below 15
kW for 11 months while being 25 kW for one month. Consequently, the customer’s normal power band would be 15 kW. An alternative could be that the customer would notify the DSO of exceptional power consumption for instance through a web-based online service and subscribe to a smaller band.

Another way to take the events of excess power band usage into account is an excess usage charge. The customer would pay the charge for the months exceeding the power band, in principle for one or two months. Customers of this kind should also have an opportunity to affect the size of their power band, regardless of the events of excess usage. There are customers similar to the customer of Figure 5.5 also in other customer groups, for instance in small-scale industries. However, these customers have typically very limited opportunities to regulate their power consumption. If the events of excess usage occurred over a period of more than three months, the customers could be steered directly to a larger power band. The excess usage could be charged for the months when the events of excess usage occurred; yet, by allowing excess usage only for two months, after which the DSO would automatically shift the customer to a larger power band. The same approach could be taken also to ordinary low-voltage customers. If the number of allowed events of excess usage were exceeded, alternatives would be either to shift the customer to a larger band by the DSO or charge the customer for the excess usage. It is not reasonable to allow excess usage for more months than suggested here, because the model becomes too complicated to apply.

The charge for the excess power band usage could be based on various alternative models. Here, we introduce a few of these. The guiding principle in the excess power band usage should be that the customer, in addition to the normal monthly power band charge, pays an extra charge, the total amount of which is higher than the monthly charge of the next larger power band. The principle is illustrated in Table 5.5. The unit prices are fixed prices, and the steps between the power bands are of equal size. In other words, if the amount of a monthly charge for a 5 kW band is 20 €/month and the power band charge for a 10 kW band is 40 €/month, the steps would be at intervals of 20 €. In that case, the charges for excess power band usage should be more than 20 € in order for the charge to be a real extra charge stimulating the customer to avoid excess usage of the power band.
Table 5.5 Formation of charges for excess power band usage. The unit prices for power bands are examples only.

<table>
<thead>
<tr>
<th>POWER BAND (kW)</th>
<th>PRICE (€/kW, month)</th>
<th>MONTHLY CHARGE (€, month)</th>
<th>EXCESS USAGE CHARGE (€, month)</th>
<th>MONTHLY CHARGE (€, month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>4</td>
<td>20</td>
<td>24</td>
<td>44</td>
</tr>
<tr>
<td>10</td>
<td>4</td>
<td>40</td>
<td>24</td>
<td>64</td>
</tr>
<tr>
<td>15</td>
<td>4</td>
<td>60</td>
<td>24</td>
<td>84</td>
</tr>
</tbody>
</table>

The example above could be a suitable calculation method for excess usage. Electrotechnical determination of charges for excess power band usage can be carried out as follows. The charges of mobile operators for exceeding the minute packages are typically threefold compared with the package prices. Similarly, in the power band scheme, the charge for exceeding the power band could be threefold compared with the normal power band charge. In other words, a threefold charge would be multiplied by the unit price of the power band and by the highest power exceeding the power band. Now, if the excess usage were 2 kW, in the case of Table 5.5 this would mean 3 x 4 €/kW, month x 2 kW = 24 €, month.

Another option would be to add up the events of excess usage, in which case they would constitute the customer’s energy rate. Now, excess usage below 100 kWh could cost 24 € per month, while excess usage above 100 kWh would cost, for example, 36 €/month. In this option, similarly to the other alternatives, the customer is not charged for excess usage events, if their number remains below ten.

Although we have now considered power band excess usage, the related charges and the customers’ consumption behaviour, we are not able to say exactly how the customers’ consumption habits will be affected by the power band pricing. Therefore, pilot studies on the topic are required. The objective of this section has been to show which issues are worth addressing in the implementation of the power band scheme, and which mistakes should be avoided. The principles introduced here represent suggestions and ideas that might work. In practice, pilot studies could be conducted in the field to determine the most viable basis for the pricing of excess power band usage. It is also important that the DSOs apply similar practices in the initial stage of the pricing scheme to avoid misunderstandings.
5.4 Power band: energy efficiency perspective

An advantage of the power band scheme is the incentives it provides for energy efficiency. Energy efficiency is a broad concept, and therefore, when considering the electricity market, the effects of the power band scheme should be addressed from the perspectives of both the customer and the distribution system. The following figures provide the AMR data of a few customers. The points in the figure, that is, the customer’s hourly powers, show that the customer has opportunities to change over to a smaller power band, in other words, to improve the energy efficiency, and thereby affect his/her distribution pricing.

![Figure 5.5 Mean hourly powers of a domestic customer for a period of one year. The figure shows that the customer obviously has potential to scale his/her power band down.](image)

The red line in the figure depicts the customer’s highest hourly power at present. Now, according to the highest hourly power, the customer would subscribe to a band of 15 kW. If the customer scaled the band down to the 10 kW level indicated by the green line in the figure, his/her distribution charge would become lower. This approach may be considered to represent the concept of demand response, which is an example of energy efficiency from the perspective of the distribution system. Demand response would mean that the customer would not use all his/her electric devices at the same time, but would shift his/her electricity consumption or cut it down so that the consumption would be more evenly distributed among the hours of the day. For the customer of Figure 5.5, the hourly powers often exceed 10 kW at the beginning of the year. If the customer had opportunities to shift his/her consumption or cut it down at the hours of the highest powers, the idea of demand response would materialise and the energy efficiency would improve from the customer’s point of view. Demand response is essential also for the distribution system as it can be used as a means to
boost the efficient use of network capacity. In practice, considerations are based on market-based
demand response, but in an optimal situation, the aspects of both the network and the markets are
simultaneously taken into account when demand response is carried out.

The second customer in Figure 5.6 has even more potential for demand response. If the customer
were charged for the highest hourly power, he/she would have a band of 20 kW in the initial stage
when changing over to the power band pricing scheme. In reality, the customer would do well with
a 10 kW band, and he/she could be able to subscribe to a 5 kW band by adjusting his/her
consumption habits or by pursuing energy efficiency. Here, it is however worth noticing that
optimisation of the band would not be mandatory, and it would not lead to consumption control or
other similar situations. Almost all customers have potential to scale their power band down.

Figure 5.6 Mean hourly powers of a second domestic customer for a period of one year.

The effects of actions towards energy efficiency are clearly visible in Figure 5.7, which illustrates
the hourly powers of an individual customer for three consecutive years. Although there are no
exact background data available of the customer’s consumption habits, the figure shows clearly that
the customer’s load curve has levelled out and the peak power has decreased. The customer has not
had a power band available, yet his/her behaviour has developed similarly as if steered by a power
band.
Figure 5.7 Mean hourly powers of a domestic customer for three years. The customer’s data have been measured from the beginning of the year until July (4,940 h). The energies and mean powers for the period are: year 2006: 11.9 MWh and 2.41 kW, year 2007: 10.5 MWh and 2.13 kW, year 2008: 10.4 MWh and 2.11 kW. The lowest temperatures have been -29.7 °C (2006), -35.5 °C (2007) and -18.9 °C (2008).

We can see that a customer can significantly improve his/her energy efficiency by adjusting his/her consumption habits; for instance, it is maybe not necessary to inefficiently keep all electric equipment on at the same time. The customer can cut down unnecessary electricity consumption, for instance by switching lights off when not needed. Energy efficiency is also promoted by avoiding the unnecessary simultaneous use of all electric equipment. The customer also has other, more powerful incentives to replace devices that consume large amounts of electric energy and power. For instance, accumulating electric heating can be replaced by a full-power capacity ground heat pump. Now, a considerably smaller power band can be selected, and the consumption of electric energy is reduced.
There are also other reasons why the power band pricing scheme can be considered as a tool to promote energy efficiency. In Finland, most of the peak load in electricity generation is produced by methods that generate the largest emissions. If the consumption peaks can be reduced at the national level, we may assume that it is also possible to reduce the peak powers and thereby have a positive impact on energy efficiency and reduction of emissions. This is illustrated in Figure 5.8.

If the amount of power and energy consumed can be reduced at the national level, also the use of renewables in energy production can be boosted. This supports the energy efficiency targets of the EU. Moreover, in electricity transmission and distribution, the energy efficiency would show as a reduction in transmitted energy and powers, and thereby, as reduced losses.

### 5.5 Effects of power band for different stakeholders

The features of the power band from the perspectives of different stakeholders are given in Figure 5.9.
For the customer, the power band pricing scheme would be cost reflective, as the customer would only pay for the network capacity he/she has used or reserved. The distribution tariff would thus be unambiguous, as it would have one tariff component only. Two- or three-component tariffs would confuse customers, similarly as the present distribution pricing scheme. The intelligibility of the power band would be supported by the fact that the concept of band is already familiar to customers for instance from internet broadband. In the power band scheme, the customers would have a genuine opportunity to affect their distribution charges, and the scheme would not provide contradictory steering signals. The power band would also partly encourage customers to develop distributed generation, if the customers could thus decrease their subscribed power. The primary benefit of the power band is probably that the customers are encouraged to use energy efficiently from the perspective of the distribution network; in other words, to cut down the required distribution capacity.

From society’s point of view, the power band would promote the energy efficiency targets and support the climate and energy policy, where energy efficiency is considered from a holistic system perspective. Power band would enable market-based demand response, and thereby promote the functioning of the electricity markets. In addition, it seems that the power band pricing scheme does not conflict with the prevailing regulation and legislation.
For a distribution system operator, the pricing scheme would guarantee predictable revenue streams, as the fixed monthly charge for all the customers around the year would help in keeping the turnover at a desired target level. That way, no significant changes would take place in the turnover between years, as this has been taken into account when preparing the pricing scheme. The previous chapters have addressed cost formation for DSOs. It has been shown that the power and fixed charges constitute a significant proportion of costs. The power band would, in particular, be cost reflective, and support the objectives defined above. According to the energy efficiency directive, the distribution system operators should provide services and encourage customers in efficient optimisation of electricity consumption. By the power band pricing scheme, the requirements set by the directive are met. When remotely read meters have been installed at all customers, there is infrastructure required for the power band. However, some effort will be required from the DSOs to upgrade or modify their information systems to meet the needs of the new tariff scheme.

Power band as a distribution pricing scheme would also be compatible with the retail tariff, and thus, distribution pricing would be a feasible option for the retailer. The retailer would have more opportunities to develop its price products, and the retail tariffs would not be confused with the distribution tariffs. The distribution pricing scheme would also enable market-based demand response, yet the power band would reduce the potential of the demand response. The demand response potential would decrease, because the customer’s controllable power would be smaller as it would be limited by the subscribed distribution capacity. On the other hand, the power band would limit the occurrence of high power peaks and encourage the customers to optimise their total consumption.

5.6 Marginal costs of the power band

A benefit of the power band is that the changes in the power consumption affect both the customers’ distribution charge and the DSO’s long-term marginal costs by the same mechanism. Thus, it has to be ensured that the prices determined for the bands allow network investments when the loads increase. The situation is illustrated by an example of the replacement value of a distribution network of a DSO in relation to the peak powers at different voltage levels. The replacement value is converted into annual costs with a 40-year lifetime and a 5% interest rate.
low-voltage networks 320 €/kW = 18.6 €/kW, a = 1.55 €/kW, month
medium-voltage networks 300 €/kW = 17.5 €/kW, a = 1.46 €/kW, month
primary supply station level 100 €/kW = 5.8 €/kW, a = 0.48 €/kW, month
whole DSO 720 €/kW = 42 €/kW, a = 3.5 €/kW, month

The company turnover is 4.4 M€ and the annual peak power 50 MW. Thus, we obtain a turnover to power ratio of 88 €/kW a year, that is, 7.33 €/kW a month. In practice, the price for the power band has to be determined more accurately, as discussed above. This price, however, can be used as a baseline against which to compare the above network marginal costs. We can see that the power band price determined this way would ensure the funding for the network reinforcement investments.

5.7 Transition to the power band pricing scheme

The present distribution pricing scheme is in need of reforms; as shown in this report, these reform demands could best be met by the power band pricing scheme. Considering distribution pricing, the transition to the power band scheme could take place either partly or completely, depending on the interests and objectives of the stakeholders in the electricity market. To guarantee the security of an individual customer, transition to the power band pricing scheme should be gradual. In the initial stage, the power band would be included in the standing charge of the electricity distribution. Instead of the fixed distribution charges and standing charges that are based on the size of the main fuse, the network companies could provide power-based bands. In the power band model, there would be only one pricing scheme, which would, however, include more steps than the present scheme of fixed charges, which is based on the size of the main fuse. Because the distribution pricing practices vary between the DSOs, there is an obvious need for harmonisation in the field. In the DSOs, the target could be to replace the standing charge by the power band during a period of one year. At the earliest, this could take place in 2015, when all customers would already have AMR meters at their disposal, and the DSOs would have time to ensure that the metering systems are operational. The time of transition would be the same for all DSOs, and all DSOs should participate in the reform to guarantee that all the customers and retailers all over the country would be treated equally.

The power bands offered by DSOs would be given in kilowatts equally by all DSOs in the pricing scheme. First, it would be advisable that all DSOs also applied the same steps in the power band...
system. The bands could start from 5 kW and continue in steps of 5 kW, in other words, 5 kW, 10 kW, 15 kW and so on. The steps of this size are justified by the present main fuse system and because of the equitable treatment of the customers. In the initial stage, when changing over from the standing charges to the power band, the steps between the power bands should be quite large; this way, too frequent occurrences of excess power band usage could be avoided in the first years. On the other hand, we are not able to say how the consumption habits of the customers would change, and therefore, the steps between the power bands should be quite large.

Information of the transition to the new power band pricing scheme should be provided well in advance. Hence, if the transition were carried out systematically from the beginning of year 2015, the customers should be informed of the process at the beginning of 2014 at latest. Information about the transition to the new distribution pricing scheme could be provided for instance together with the electricity bills, on the DSOs’ web pages and in the media. The customers would be informed in their bill about their highest hourly power of the present year and the resulting power band and monthly charge. Together with the present distribution price and consumption data, the customer would be informed of the opportunities to scale the power band down and cut down the electricity bill.

A suitable power band for the customer would be determined directly based on the DSO’s customer data of the hourly consumption. For instance in the initial stage of the transition process, when the power band would replace the standing charge, the billing could be based on the highest hourly power. The customers would be allowed to exceed their power bands for instance ten times a year in each power band. This rule could be applied for a few years. When the customers are familiar with the new pricing scheme, the bands could be offered in steps smaller than 5 kW, simultaneously increasing the weight of the power band in the distribution pricing.

As an increasing part of the customer’s distribution charge would be based on the power band, the size of the power band could be determined basically according to the same principle as before. Now, the customer would be allowed more events of excess power band usage, which would increase in size along with an increasing power band size. At the same time in this stage, the customers would be charged for excess usage that exceeds the number of allowed events. Before changing over from the combined power band and energy rate to a full power band, the proportion of power band pricing of the distribution price should be increased to at least 50%. This stage
would be reached faster by some DSOs than by others. The standing charges of some DSOs are already at a higher level when compared with other companies.

During the years following the distribution pricing reform, the target would be to increase the proportion of the power band in the distribution charge at least to half of the charge. Full power band pricing could be introduced to the customers over a period of several years. For instance, after changing from the standing charge to the power band, the proportion of the customers’ power band charge in the distribution pricing could be increased and the proportion of energy rate could be decreased, as shown in Figure 5.10. The process should take several years to ensure that the changes in one year are not too radical for the customers. For enterprises, the changes over several years should not be too radical either to avoid unreasonable damage to the business.

![Figure 5.10 Changes in the distribution charge components for a K1 type electricity user of a DSO when changing over to the power band pricing scheme.](image)

The new scheme would be launched in 2015 at the earliest, when the power band pricing would replace the standing charge. Over the coming few years, the proportion of the standing charge, that is, the power band, would increase, and the proportion of energy rate would decrease. The distribution charge as a whole would remain constant or at the target level determined by the DSO.

### 5.8 Implementation of the power band pricing scheme

In this report, only the outlines of the implementation of the pricing scheme have been discussed. However, for the practical implementation of the scheme, the system has to be piloted in an actual operating environment.
The customers’ present standing charges would first be converted into a power band. For the purpose, the DSOs should collect AMR metering data of each customer’s highest hourly power of the year. These data would be used to determine the customer’s power band in the initial stage. Moreover, the DSOs should determine the charges collected at present from the customers’ standing charges for distribution. After this, there are various alternatives to determine the unit price, of which the DSO can choose the one that best suits its purposes. However, it would be important to have a fixed price as the unit price (€/kW, month) when converting the standing charge into a power band; thus, it would be easier to adjust the prices in the future and avoid any volume discounts.

An alternative would be that the DSO determines a single unit price €/kW for a year based on the AMR data and standing charges, which is applied to all customers of the DSO. In that case, the unit price €/kW would be constant for all customers, and it would be adjusted to a level where the revenues collected from the standing charges remain constant, thereby guaranteeing that also the changes in prices remain reasonable for the customers.

Another alternative would be to group the customers according to their power bands so that for instance the customers with a 5 kW band would comprise one group, the customers having a 10 kW band another, and so on. The revenues produced by the standing charges of the customer group are added up and divided by the number of customers in the customer group. The resulting annual power band charge has to be further modified between the customer groups so that the unit price of the band is constant. Thus, with a fixed unit price for the band, for instance 2 €/kW a month, a 5 kW power band would cost 10 € a month and a 10 kW band 20 €.

First, the DSO would automatically determine a suitable band for the customer based on the metered hourly data for the highest hourly power of one year. For instance, if the power band were included in the standing charge for distribution in 2015, the customer billing could first be based on the highest hourly data metered for year 2014. The customer would have a right to switch the power band once a year. The reason for allowing only one switch a year is that customers with electric heating would probably try to order a smaller band for summer than for winter, when the consumption of electrical energy is considerably higher. Furthermore, the power band is intended to be a fixed monthly charge around the year. The purpose is not to randomly switch the power band and the related monthly charge. A year may sound a long time; however, the contracts with mobile operators and electricity retailers are typically made even for two years. During the transition, if the customer wanted to have a smaller power band than the one determined by the DSO, the customer
should notify the DSO through the company’s internet service or by calling the customer service. Naturally, a prerequisite for the switch is that the band would be adequate for the customer. If this condition were not met, the DSO would inform the customer about an excess usage of the band for instance through an online service, and switch the band automatically to a larger one or charge the customer for the excess usage. If the customer wants to subscribe to a smaller band than what is suggested by the DSO, the customer should be charged for the switch. This way, unnecessary switches between the power bands could be avoided.

In the initial stage, that is, when switching from the present standing charge to the power band, the customers would be allowed to exceed their band ten times in each power band. In practice, the DSO would suggest a suitable band for the customer, in addition to which the customer could choose a suitable band for him/herself. This would remove the risk of an oversized power band.

In the power band pricing scheme, the customer has an opportunity to influence the subscribed band and thereby the amount of the distribution charge. It would be advisable to inform the customer about the opportunities to reduce the power consumption similarly as about the means to reduce the energy consumption. This information could be given together with the electricity bills and in the DSO’s newsletters. Either the electricity retailer or the DSO could provide the customer with tips on energy efficiency or how to switch to a smaller power band.

The process of including the power band scheme fully in the distribution pricing would be carried out over several years. The power band could replace the present standing charge in distribution pricing as soon as the DSOs have managed to raise the proportion of the power band price to the 50 % level of the total distribution price. After this, a few more years are required to reach a full power band pricing scheme. At the same time, it would be necessary to modify some of the principles related to the power band in order to avoid any changes that would be unbearable from a customer’s point of view.

The power band could be determined on a similar basis as previously, that is, by the highest hourly power of a year, because the customers are already familiar with the principle. Now, more events of excess usage would be allowed for the customers depending on the size of the power band. For example, a band of 5 kW could be exceeded ten times a year, and a 15 kW band 30 times. The customer would be charged for excess usage exceeding the allowed limits, or he/she would be shifted to a larger power band. In this context, the DSOs could also introduce power bands in
smaller steps; the bands could be for instance 5 kW, 8 kW, 10 kW, 13 kW and so on. In the future, the steps between the bands could be even smaller.

When changing over to a full power band scheme, special attention should be paid to exceptional customers, the power consumption of which during one month may be multiple compared with the consumption for the rest of the year. For customers of this kind, a stepped scheme should be used for the events of excess power band usage, or the customers should be tracked based on their monthly hourly peak powers, or the customers themselves should inform about their desire to select a smaller power band either through an online service or by contacting the DSO by phone.

5.9 Power band as a distribution pricing scheme: a summary

As a whole, the transition process from the present distribution pricing scheme to the full power band scheme would take several years. The transition process is illustrated by figures and tables below.

In the initial stage, the power band would replace the present standing charge. This would be carried out by determining the highest hourly power from a customer’s hourly data for one year, which the DSO would use as a basis to determine the customer’s power band. The DSO would determine the prices for the power bands according to its target levels. The smallest band would be 5 kW and the bands would be defined in steps of 5 kW. Hence, all the customers would have same power bands, but the energy tariffs for the distribution could still be selected from various alternatives. The power bands for the customers of a DSO and the resulting monthly charges would thus be as shown in Table 5.6.

<table>
<thead>
<tr>
<th>YEAR 2011</th>
<th>Customer 1</th>
<th>Customer 2</th>
<th>Customer 3</th>
<th>Customer 4</th>
<th>Customer 5</th>
<th>Customer 6</th>
<th>Customer 7</th>
<th>Customer 8</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max (kW)</td>
<td>16.8</td>
<td>10.07</td>
<td>13.39</td>
<td>9.75</td>
<td>10.11</td>
<td>10.55</td>
<td>8.23</td>
<td>15.68</td>
</tr>
<tr>
<td>Power band (kW)</td>
<td>20</td>
<td>15</td>
<td>15</td>
<td>10</td>
<td>15</td>
<td>15</td>
<td>10</td>
<td>20</td>
</tr>
<tr>
<td>Price (€, month)</td>
<td>40</td>
<td>30</td>
<td>30</td>
<td>20</td>
<td>30</td>
<td>30</td>
<td>20</td>
<td>40</td>
</tr>
</tbody>
</table>

In the initial stage, the customers would have an opportunity to choose whether they accept the power band suggested by the DSO or whether they would like to have some other band. In the initial stage, the selection of power band would be free of charge. The customers could determine a suitable band for themselves by using the DSO’s online service or by calling the DSO and inquiring...
about possible solutions for a suitable power band. In Figure 5.11, the power band of a customer would be 20 kW.

![Customer with a flat rate tariff and a 3x25 A main fuse](image)

Figure 5.11 Hourly data for one year of a domestic customer living in a detached house.

The customer decided to take a 15 kW power band instead of the 20 kW band recommended by the DSO. The customer knows now that he/she has a power band of 15 kW, which costs 30 € a month, and he/she may exceed the band ten times during the year, after which he/she is automatically shifted to a larger power band. As the power band replaced only the standing charge, the customer will have to pay an energy rate in the distribution charge based on the consumed energy. Consequently, the basis for billing could be as illustrated in Table 5.7.

<table>
<thead>
<tr>
<th>Unit price 2 €/kW, month</th>
<th>5 kW</th>
<th>10 kW</th>
<th>15 kW</th>
<th>20 kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power band (€, kk)</td>
<td>10</td>
<td>20</td>
<td>30</td>
<td>40</td>
</tr>
<tr>
<td>Allowed excess usage events (number, a)</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td><strong>Flat rate distribution tariff</strong></td>
<td>Consumption charges</td>
<td>cent/kWh</td>
<td>2.76</td>
<td></td>
</tr>
<tr>
<td><strong>Time-of-day distribution tariff</strong></td>
<td>Consumption charges</td>
<td>cent/kWh</td>
<td>day</td>
<td>night</td>
</tr>
<tr>
<td></td>
<td>3.41</td>
<td>1.69</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The process would continue so that the DSOs would raise the proportion of the power band to a 50% level in the distribution pricing over a period of a few years; in other words, the proportion of the energy rate in the distribution pricing would decrease. The DSO would suggest a suitable band for the customer, thereby avoiding an oversized band. Should a customer like to have a larger band,
he/she could order it for free. If the customer wanted to have a smaller band than the DSO suggests, he/she would have to pay a small extra service fee for the switch.

After the most critical transition phase, the DSOs could start to offer power bands in smaller steps, for instance at 5 kW, 8 kW, 10 kW and 13 kW. The practice for the determination of the power band would be the same as before: The customers have a power band, which they may exceed for a certain number of times. In this stage, it may not be advisable to adjust the basis for the determination of the power band any longer. When changing over to the power band, a unit price of 2 €/kW a month is assumed for the standing charge. When the proportion of the energy rate has been removed, as a result, the unit price of the power band has increased for instance to 4 €/kW. Now, the customer prices would be as shown in Table 5.8.

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Power band (kW)</td>
<td>8</td>
<td>15</td>
<td>10</td>
<td>8</td>
<td>10</td>
<td>8</td>
<td>13</td>
</tr>
<tr>
<td>Price (€, month)</td>
<td>32</td>
<td>60</td>
<td>40</td>
<td>32</td>
<td>40</td>
<td>32</td>
<td>52</td>
</tr>
</tbody>
</table>

As the weight of the power band increases in the distribution pricing, the number of allowed excess usage events for customers should be increased in steps. This would provide flexibility in the pricing. If the customer is not able to stay within the limits of the subscribed power band, that is, the number of allowed events is exceeded, he/she is automatically shifted to the next power band. The practice applied to the determination of the power band is still that the DSO suggests a suitable band, and the customer may either switch it or keep the suggested band. The power band pricing scheme is not suitable for all customer types because of the price structure; therefore, an excess usage charge for one or two months should be introduced for such customers. An example of distribution pricing in a full power band scheme is illustrated in Table 5.9.

<table>
<thead>
<tr>
<th>Data: 4 €/kW, month</th>
<th>5 kW</th>
<th>8 kW</th>
<th>10 kW</th>
<th>13 kW</th>
<th>15 kW</th>
<th>18 kW</th>
<th>20 kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power band (€, month)</td>
<td>20</td>
<td>32</td>
<td>40</td>
<td>52</td>
<td>60</td>
<td>72</td>
<td>80</td>
</tr>
<tr>
<td>Allowed excess usage events (number, a)</td>
<td>10</td>
<td>15</td>
<td>20</td>
<td>25</td>
<td>30</td>
<td>35</td>
<td>40</td>
</tr>
<tr>
<td>Excess usage charge (€, month)</td>
<td>24</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

In the later stage, the DSOs could offer power bands in smaller steps, such as 1 kW, to their customers. In this stage, the customers should have a home automation system of some kind, a consumption display or similar to monitor the consumption at an hour level.
6 Conclusions

Promotion of energy efficiency and reduction of the environmental effects of energy generation call for changes in the entire energy system. Here, distributed generation by renewables such as solar and wind power play a key role. As it is difficult to predict generation of this kind, demand response is required to balance variation in consumption and generation. Moreover, new pricing schemes are needed to encourage the customers in energy efficiency and demand response. The target is to establish a pricing scheme for DSOs that encourages the end-users to behave so that the energy efficiency of the whole energy system, including generation, transmission and distribution, is maximised and the total costs to the national economy are minimised. Furthermore, the pricing scheme has to be cost reflective, equitable and intelligible to all parties involved.

The study has addressed opportunities to develop the tariff structures from the perspectives of distribution system operators, customers and other stakeholders in the energy sector. The present tariff structure has to be developed, in particular because of its inadequate cost reflectivity and weak incentive effects. These issues will raise problems especially under the changes that the energy system will face in the future; the measures to boost energy efficiency will impact on the amount of transmitted energy and the power demand of the customers, and thereby the revenues and expenses of the DSO. In practice, the expenses of a DSO mainly depend on the peak power on the network, whereas in the present tariff structures, which have a fixed standing charge and an energy rate, a majority of the revenues are based on the amount of transmitted energy. Thus, in the present tariff scheme, changes in the electricity consumption do not affect the revenues and expenses equally. For instance, a customer’s own small-scale electricity generation or a heat pump in a building with electric heating improves the total energy efficiency and decreases the volume of energy transmitted on the network, yet does not usually impact on the peak power taken by the customer from the network. Thus, actions of this kind reduce the revenues of the DSO, but do not influence the expenses. From the distribution network’s viewpoint, the present tariff structure does not encourage the customers to optimise their electricity consumption either, and thus, has no incentive to improve the energy efficiency of electricity distribution. Hence, we may state that the tariff scheme should be developed to be more cost reflective for the DSO, and to encourage the customers to optimise their electricity consumption also from the perspective of the distribution network. Furthermore, special attention should be paid to ensure that the tariff scheme does not lead to conflicts of interest between other stakeholders in the field. Now, it is a suitable moment to develop the tariff scheme,
as the tariff reform can be made parallel to the adoption of AMR meters and possible changes in the retail market model.

Considering the alternative tariff schemes discussed here, the power band pricing scheme meets best the targets set for the new tariff scheme. In the power band scheme, a customer’s distribution tariff depends on the subscribed power band (e.g. 5 kW, 8 kW, 11 kW). A pricing scheme of this kind encourages the customers to optimise their electricity consumption so that the peak power demand is decreased. As the network capacity utilisation rate increases, the long-term costs decrease, which is also financially beneficial to the customers. Energy-based pricing of electrical energy, again, encourages the customers to cut their total energy consumption. The primary factor affecting the costs of electricity distribution is the peak power of the network. Thus, for the DSO, power-based pricing is cost reflective. It is also equitable to the customers, as the costs are divided between customers so that the customer causing a higher cost pays a higher price and vice versa.

If the market model for retail markets is developed so that the retailer is responsible for the customer gateway and also charges the proportion of the DSO to the customers, the retailer will have an incentive to steer the customer’s electricity consumption toward an overall optimum for the market and the network. Now, the retailer optimises the control of customer loads, energy storages and generation according to the spot prices, simultaneously taking into account the optimal dimensioning of the power band. The size of the customer’s power band can be increased, if the costs of the switch to a larger band are lower than the benefits achieved by the market-based load control. Correspondingly, a smaller band is chosen, if the savings provided by the switch to a smaller band are higher than the losses caused by the decrease in the load control potential. In the above situation, the total energy efficiency, including electricity generation and distribution, is maximised, as the use of the network and generation capacity is optimised simultaneously. When the power band price corresponds to the marginal costs of the distribution network, and the spot price to the marginal costs of generation, the above-described scheme pursues an overall optimum of costs also at the national economy level.

The tariff scheme reform inevitably leads to changes in prices for individual customers. However, the reformed scheme is more equitable and provides better incentives for the customers; in the new scheme, the costs are also allocated better by the matching principle. The new scheme can be adopted gradually, thereby avoiding too radical changes for individual customers. At the same time, adequate revenues are guaranteed for the DSO both in the transition and the new tariff scheme.
7 Topics of further study

Tariff schemes and their effects have been discussed extensively in this report. The results obtained in the study have also raised some issues for further study, which are worth addressing in the future.

The report has addressed the effects of power band on the demand response in general. However, the effects of the distribution tariff on the market-based demand response have to be analysed in detail by taking into account the incentives produced both by the power band and the market-based demand response as well as the overall effects for the customer and the energy system as a whole.

The effects of the new tariff scheme have to be piloted in an actual operating environment before the scheme is adopted in a large scale. Special attention should be paid to the intelligibility of the tariff scheme for the customer, and to the actual effects of the tariffs on the customer behaviour. Simultaneously, the feasibility and potential of the above-described demand response should be investigated with different customers. In addition, opportunities to increase customer activity with respect to demand response should be studied.

A problematic issue when considering the tariffs for small-scale consumers is the billing of reactive power. Changes in the electric equipment possessed by customers also increase the small-scale customers’ consumption of reactive power; nevertheless, there are no incentives to reduce the reactive power, as it has no effect on billing in the present tariff scheme. No changes are expected either, if the pricing is based on subscribed power, as suggested in this report. If the pricing were based on current instead of power, this would include reactive power also. Now the problem would be that the present AMR meters typically do not record current or reactive power, and thus, changes would be required in the metering systems. Furthermore, small-scale customers are also usually not familiar with the technical concept of reactive power, and this would cause problems in informing the customers about the billing principles. Small-scale customers’ reactive powers can also be affected by various standards for electric equipment, but the network tariff should nevertheless include a proper incentive to reduce the reactive power; however, the practical implementation requires further study.

In addition to analyses and results provided in this report, the legislative aspects associated with the power band should be investigated in cooperation with the respective ministry (Ministry of Employment and the Economy).
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