IMPACT ASSESSMENT OF THE REFORM OF THE MAIN GRID SERVICE FEE STRUCTURE

TRANSLATED FROM THE ORIGINAL FINNISH VERSION DATED 26.5.2026

JUHA VANHANEN

CENTROCAMPISTA LTD

TABLE OF CONTENTS

1 INTRODUCTION

Fingrid is planning to reform the main grid service fee structure. The aim of the reform is to create a cost-based fee structure, in which the payments are allocated to customers in accordance with the causality principle. A significant change is the transition from a current consumption energy-based fee structure to a new fee structure, in which some of the fees are based on power taken from the main grid.

This impact assessment examines the impacts of the planned new fee structure on Fingrid’s customers. The review will be carried out by comparing the costs of the planned new fee structure with the current fee structure using measurement data from the year 2024. The basic assumption for the calculations is that the new fee structure will charge the same amount as would have been charged with the fees in 2024 under the fee structure and the unit prices valid in 2024[1]. The calculations are made for each connection point and customer. The analysis and reporting of the calculations is done by customer groups. The customer groups examined are producers, industry, DSOs and energy storages.

Chapter 2 of the report describes the current fee structure as well as the new fee structure, its various components and the principles for determining them. Chapter 3 describes how the impact assessment was carried out, the data used and the main assumptions under which the unit costs of the new fee structure were determined. In addition, Chapter 3 describes the calculation principles used in the impact assessment and defines the values of the unit prices of the new fee structure.

Chapter 4 presents the results of the impact assessment. The results show the difference between the new and current fee structure. Based on the results, it is possible to observe how the reform will affect different customer groups and what kind of changes will take place within the customer groups. The results show also changes in customer payments, but do not present the names of individual customers. In addition, alternative calculations, in which the pricing depends either on the geographical area or on the voltage level of the connection, are presented in Chapter 4.

Chapter 5 describes the qualitative changes that are expected to take place by the early 2030s. Electricity consumption and the input to and output from the main grid are expected to increase significantly. At the same time, significant investments are being made in the main grid, and transmission losses in the main grid are expected to increase from the current level. Similarly, major changes are expected in customers' production and consumption volumes and main grid inputs and outputs. The purpose is to assess the overall impact of these expected changes on both the components of the main grid service fee and the payment burden of customers.

Chapter 6 examines as a special issue the ability of consumption customers to manage the power they take from the main grid, if a new fee structure is introduced. In addition, Chapter 6 examines the effects of the reform on the location of new projects and the ability of DSOs to pass on the fee structure changes to their own customers. The analyses described above have been carried out qualitatively, and no dynamic effects have been modelled. Chapter 7 summarises the results and conclusions.

[1] In 2024, Fingrid did not collect three months' fees. However, this study has examined the situation in which all the months would have been charged according to the price list in force.

2 REFORM OF THE MAIN GRID SERVICE FEE STRUCTURE

2.1 Current fee structure

The current main grid service fee structure is very energy-based and exceptional in European context. Most grid fees are targeted at consumption customers, whose fees are based on energy consumption and energy taken from the main grid.

All consumption fee components (consumption fee and main grid output fee) are solely dependent on the amount of energy and are not affected by the power taken from the main grid or the power of consumption beyond the connection point (see Figure 2.1). The consumption fee, which is allocated to all consumption behind the connection point, is the most significant fee component. In 2026, the consumption fee is 10.47 €/MWh on a winter weekday and 2.97 €/MWh at other times, while the main grid output fee is 1.07 €/MWh.[1] In 2024, which is the reference year for this impact assessment, the corresponding fees were 8.96 €/MWh, 2.55 €/MWh and 0.92 €/MWh, respectively.

The fee components for production are the power plant's generation capacity fee, which is power-based, and the main grid input fee, which is based on the energy supplied to the main grid. An alternative to generation capacity fee is an energy fee for power plants with short operating times. These are determined separately in advance in December of the previous year. In 2026, the generation capacity fee is 189.50 €/MW per month, and the energy fee for short operating times is 3.80 €/MWh.[1] In 2024, the corresponding fees were 162.00 €/MW, per month and 3.26 €/MWh. In 2026, the main grid input fee is 0.71 €/MWh, and in 2024, it was 0.61 €/MWh.

The energy storage capacity fee, which is charged for the grid output and input capacities, was not introduced until the beginning of 2026. In 2026, the energy storage capacity fee is half of the power plant's generation capacity fee, i.e., 94.75 €/MW, per month, and it is charged separately for both grid input and output power.

Consumption	Consumption fee (€/MWh) - Winter weekday - Other Time	Main grid output fee (€/MWh)
Production	Generation capacity fee (€/MW) or Energy fee for short operating times (€/MWh)	Main grid input fee (€/MWh)
Energy storage	Energy storage capacity fee for grid input and output (€/MW)	Main grid input and output fee (€/MWh)

Figure 2.1. Main grid service fee structure at present.

[1] Fingrid, Main grid service fees 2026

2.2 Proposal for a new fee structure

The reform of the main grid service fee structure aims at a cost-based fee structure in which the payments would be allocated to customers in accordance with the causality principle. The reform aims to curb the growth of the power taken from the main grid and fed into the main grid to curb main grid investments that will ultimately burden main grid customers.

Increasing the transmission capacity of the main grid requires investments, the amount of which depends on the power to be transmitted. Thus, the new fee structure includes a consumption capacity fee for consumption customers and energy storages (see Figure 2.2). The consumption capacity fee takes into account the hourly peaks over different months as well as over a longer period, e.g., a year.[1]

The hourly peak over a longer period can be based on the contract power, the measured hourly peak of the previous calendar year or the rolling 12-month. In this report, the hourly peak over a longer period will be called the “annual hourly peak". The use of the annual hourly peak is motivated by the fact that it determines the ultimate capacity of each customer. The use of the monthly hourly peak is motivated by the fact that the Energy Authority has in its own regulation[2] obligated DSOs to use each month's measured hourly peak as the basis for invoicing. The uniform practice will improve the conditions for power control of customers through all voltage levels of the electricity network. Preliminarily, it is planned that the annual hourly peak and the monthly hourly peak would be weighted equally, i.e., the weight of both would be 50%.

Regarding production, the generation capacity fee is intended to remain as it is at present, i.e. it is based on the power plant's net electrical output and it is charged from all power plants over 1 MW, regardless of whether the power plant is only a production connection or whether the power plant is in a distribution network or an industrial connection. In addition, the energy fee for short operating times will be retained as an alternative to the generation fee, as currently. No consumption capacity fee will be charged from the power plants, if the power plant has only consumption for its own use. If there is other consumption in connection with production, such as an electric boiler or energy storage, the consumption capacity fee is charged.

<table>
<tr><td>Consumption</td><td>Consumption capacity fee (€/MW) based on both annual and monthly hourly peaks</td><td rowspan="3">The loss fee (€/MWh) is invoiced for all grid input and output energy, regardless of the type of customer</td><td rowspan="2">The system fee (€/MWh) is invoiced for production and consumption</td></tr>
<tr><td>Production</td><td>Generation capacity fee (€/MW) or
Energy fee for short operating times (€/MWh)</td></tr>
<tr><td>Energy storage</td><td>Consumption capacity fee (€/MW) based on both annual and monthly hourly peaks</td><td>The system fee (€/MWh) is invoiced for storage losses</td></tr>
</table>

Figure 2.2. Proposal for a new main grid service fee structure.

[1] Hourly peak refers to the average hourly power whitdrawn from the main grid.
[2] Energy Authority, Energiaviraston määräys 2340/000002/2025 [in Finnish]

To cover the costs of transmission losses in the main grid, a separate loss fee will be charged to replace the current main grid input and output fees. The loss fee covers the costs arising from the losses of the main grid. The loss fee is energy-based and is charged for all input and output energy to and from the main grid. The unit price of the loss fee is the same for both the input and output. The loss fee is intended to be based on 15-minute measurements. If an energy storage facility has both output and input within 15 minutes, these are netted and a loss fee is charged for the input or output that has become net.

In addition to the above, the intention is to introduce a system fee to cover, among other things, the costs of stability management and the acquisition of reserves. The system fee is energy-based, and it is targeted at all consumption and production. The system fee for energy storage facilities is charged only based on the loss energy caused by the storage. The system fee is also intended to be based on 15-minute measurements.

3 IMPLEMENTATION OF THE IMPACT ASSESSMENT

3.1 Approach

The impact assessment compares the differences between the current and the new fee structure. The data used is the metering and billing data of each connection point in 2024. The assumption for the calculations is that the new fee structure will charge the same amount as would have been charged with the fees for 2024 without the fee reductions granted[1]. The impact of congestion income recorded in the income statement for the year in question and reducing the payment burden of customers has also been eliminated from the calculations.

The calculations are made for each main grid connection point. The results are reported by customer groups. The results also show a more detailed distribution of changes within each customer group. Furthermore, the calculation produces information on the weight of the different fee components of the new fee structure.

3.2 Data and assumptions

The connection point specific data used in the calculations has been obtained from Fingrid's information systems. The data has included the annual sums of input and output energies and consumption energy, as well as the hourly peak powers of each month. From the financial information, the total amount of invoicing for the year and its breakdown into the payment components of the current fee structure have been used. The financial information has been calculated based on the assumption described above that all months of 2024 would have been charged in accordance with the valid price list.

[1] In 2024, Fingrid did not collect three months' fees. However, this study has examined the situation in which all months would have been charged according to the price list in force.

The calculations include all Fingrid's customers for 2024. This also includes customers who have started using the connection in the middle of the year or stopped using the connection during the year. The calculations have first been made by connection points, and then the connection points of each customer have been combined. The calculations have used netted input and output energies in accordance with the netting agreements in force. The power outputs of the power plants have been determined based on the power plant fees paid in 2024, which means that the power plants that have been in use for part of the year have been taken into account in the comparison in the correct way. Producers whose connections have had significant consumption and who have previously been charged a consumption fee of at least 1,000 € per year have been charged also a consumption capacity fee. No consumption capacity fee has been charged from other producers. No consumption capacity fee has been charged for any backup connections.

3.3 Setting up payment components

The payment components of the new fee structure are defined in accordance with the following cost-based principles:

1. The loss fee is determined based on Fingrid's net loss costs for 2024 (approximately 70 M€), and it is allocated to both input and output energy of equal value and allocated to all customers. Loss costs include hedge costs, but not cross-border transmission loss costs covered by congestion income.
2. The system fee is determined based on system costs corresponding to Fingrid's current costs (approximately 60 M€) and allocated to all consumption and production, apart from energy storage facilities, the fee for which is based solely on the loss energy of the energy storages.
3. The power plant's generation capacity fee collects the same amount of money as in 2024 (approximately 40 M€). Similarly, the energy fee for short operating times power plants collects the same amount of money as in 2024 (< 1 M€).
4. The consumption capacity fee is determined so that it and all other fee components described above collect the same amount of money as would have been collected in 2024, if all months had been invoiced. 50% of the consumption capacity fee is based on the annual hourly peak and 50% on the monthly hourly peaks.

It should be noted that in 2024, Fingrid's main grid service fee level was below the highest payment level allowed by law, as congestion income was used to reduce customer fees.

According to these principles, the unit prices of the various components of the new fee structure are:

- Consumption capacity fee: 1340 €/MW, month
- Generation capacity fee: 162 €/MW, month
- Energy fee for short operating times: 3.26 €/MWh
- Loss fee: 0.59 €/MWh
- System fee 0.39 €/MWh

In the calculations, the annual hourly peak is the highest measured hourly power in 2024. In practice, the hourly peak over a longer period can be, e.g., the hourly peak of the previous year or the last rolling 12 months, or a separately agreed contract power.

The above-mentioned fee components describe a situation in which the new fee structure would have been in place in 2024, and main grid service fees would have been collected every month of the year, and congestion income would have been used to reduce the payment burden of customers by the same amount as in 2024. The prices do not describe the present or future prices but only concretize the situation in 2024.

The results presented in Chapters 4.1 to 4.5 are based on the fees calculated at the unit costs above. Chapter 4.6 presents an alternative calculation, in which the loss fee is set regionally. Chapter 4.7 presents a calculation, in which the consumption capacity fee and the generation capacity fee of the power plants have been set according to the voltage level of connection so that the charges are lower at the 400 kV voltage level than at the 110 kV and 220 kV voltage levels.

4 CALCULATIONS OF IMPACTS

4.1 Overview

The new fee structure changes the cost burden of customer groups. Figure 4.1 shows the allocation of fees under the current and new fee structure to different customer groups. Producers include (i) power plants connected to the main grid that have no consumption other than consumption for own use and are not subject to a consumption capacity fee, and (ii) main grid connected power plants that have demand behind the connection point and are subject to a consumption capacity fee. The group DSOs and others includes all DSOs and a small number of consumption customers that are not industrial in nature, but of which there were too few to form a separate customer group. In addition, it is necessary to note that there are power plants also included in the industrial and DSO customer groups.

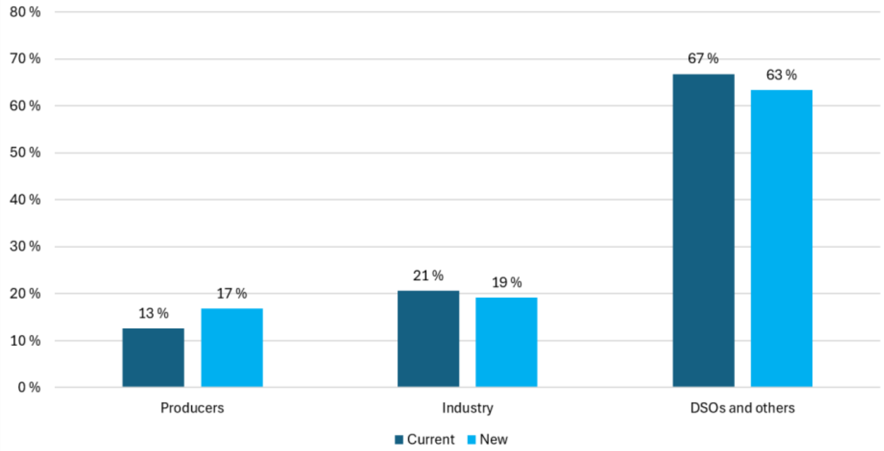

Figure 4.1. Distribution of fees by customer group, calculated with 2024 data.

In 2024, the number of energy storage customers was so small that their significance was non-existent (rounded to 0%), so they have not been included in the summary figures. Energy storages are examined in more detail in Chapter 4.5.

In the new fee structure, producers' share of total fees is 17%, while in the current fee structure it is 13%. Correspondingly, the share of industrial customers decrease from 21% to 19%, and the share of DSOs and others decrease from 67% to 63%. In the new fee structure, the loss fee (0.59 €/MWh) is approximately the same as the current grid input fee (0.61 €/MWh), but lower than the grid output fee (0.92 €/MWh) in 2024. The system fee for production and consumption (0.39 €/MWh), on the other hand, is lower than the loss fee.

As there are also power plants in industry and distribution networks that pay the generation capacity fee, the energy fee of short operating times, the loss fee for input into the grid and the system fee for net production, the total share of production in the new fee structure is 26%. In the current fee structure, it is 19%.

Compared to the current fee structure, the total fees charged to producers will increase by 33% (see Figure 4.2). In euros, the increase is approximately 0.4 €/MWh. The fees for industrial customers decrease by 7%, and the fees for DSOs and others decrease by 5%. The relatively larger change for producers is explained by the fact that the fees charged by producers per energy and power units are currently lower than those of consumption customers, i.e., industry and DSOs.

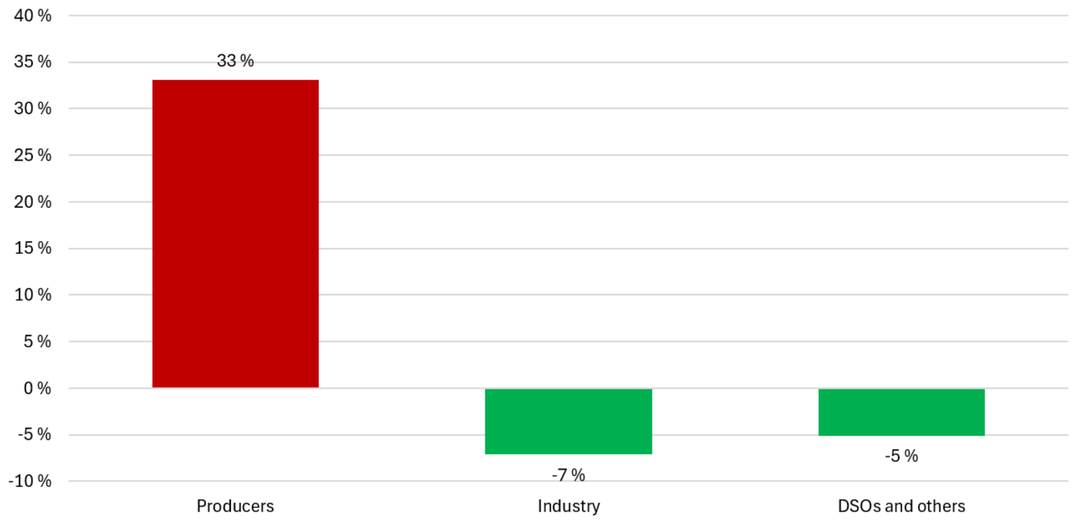

Figure 4.2. Relative changes in fees, calculated using 2024 data.

The most significant change in the new fee structure is the shift from energy-based fees to capacity-based fees. In the current fee structure, the share of capacity fees is only about 10% in total, while in the new fee structure, the share of capacity fees rises to 68%, based on 2024 data. Of this, the share of consumption capacity fee is 58 percentage points, and the share of generation capacity fee is 10 percentage points. The share of loss fees is 17 % and the system fee is 15 % (see Figure 4.3).

For industrial and DSO customers, the consumption capacity fee is clearly the most significant payment component in the new fee structure, whereas previously the majority of fees were collected through consumption fees. The fees of producers are divided quite evenly between the generation capacity fee, loss fee and system fee. Compared to the current fee structure, the generation capacity fee is the same, the loss fee is slightly lower than the current grid input fee, and the system fee is a completely new fee component.

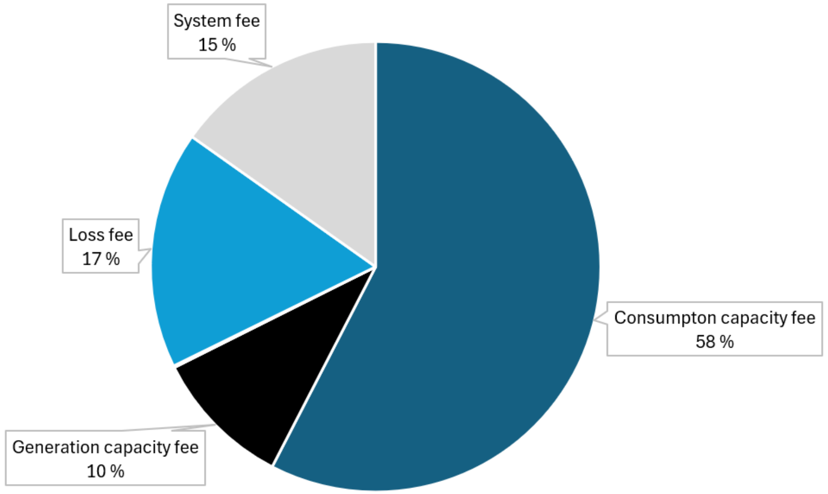

Figure 4.3. Relative shares of the fees in the new fee structure, calculated using 2024 data.

Customer-specific changes can be examined based on both relative changes and monetary changes. Figure 4.4 shows the distribution of relative changes. The figure shows that 40% of customers have lower fees and 60% of customers have higher fees. For about 20% of customers, fees decrease by more than 10%, and for about 20% of customers, fees increase by more than 30%. The increase will mainly affect producers, for all of whom the fees will increase (see Chapter 4.2 for more details).

Figure 4.5 shows the monetary changes in the fees. The figure shows that the monetary changes are moderate for the majority. For about 60% of customers, the change is between -100,000 € and +100,000 € on an annual basis. On the other hand, at both extremes of the changes, the changes in euros are large. The benefits are especially high for some customers, as 10% of customers benefit more than 400,000 €/year. The different customer groups are examined in more detail in Chapters 4.2 – 4.5.

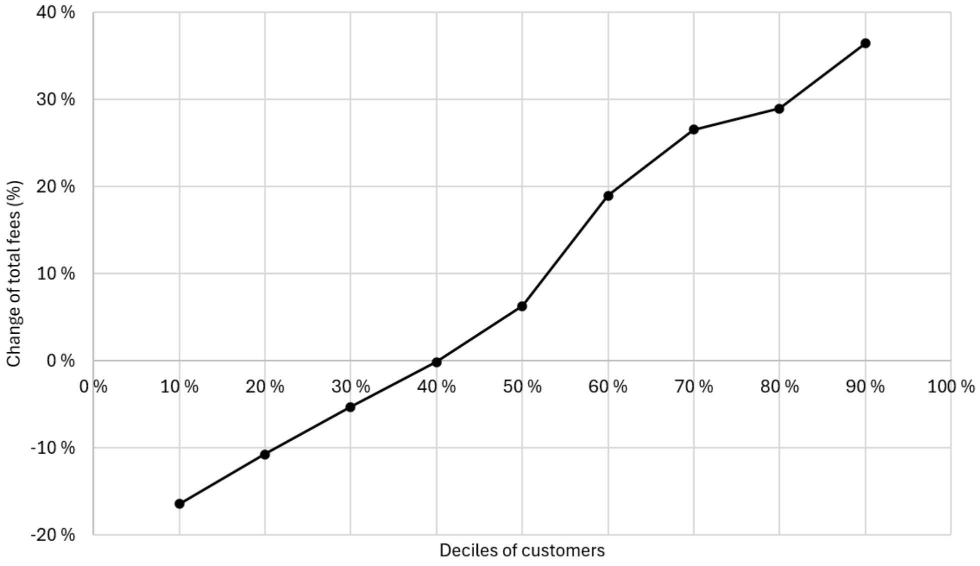

Figure 4.4. Distribution of relative changes in payments, including all customers.

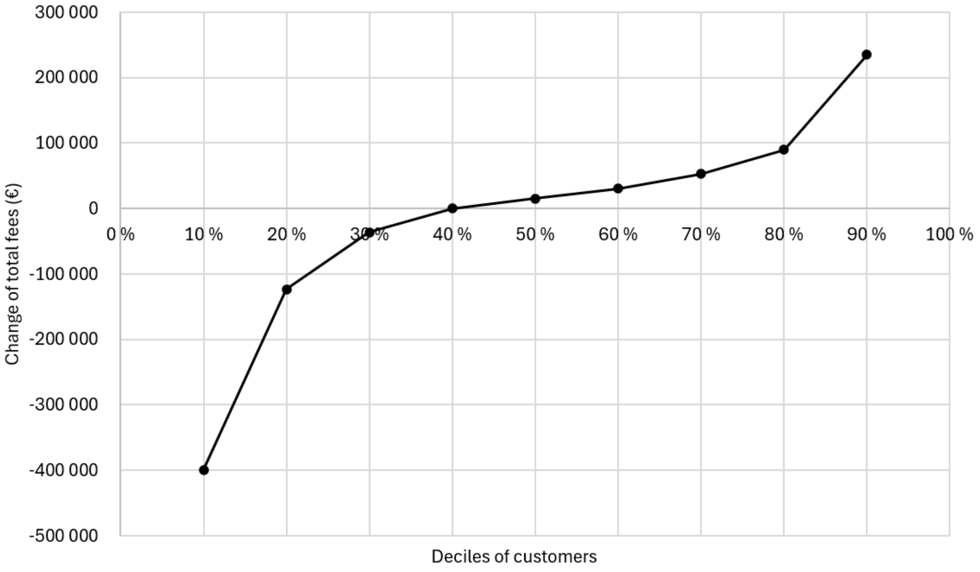

Figure 4.5. Distribution of changes in payments in euros, including all customers.

4.2 Producers

In the new fee structure, the total fees of producers increase by 33%, which corresponds to an increase of approximately 0.4 €/MWh. The customer-specific distribution is shown in Figure 4.6, which shows all producers who have had production in 2024. For most producers, the increase in fees is between 20% and 45%. Only the change of four producers is outside this range. For these exceptional customers, the change appears to be relatively larger due to the current netting agreements. In the calculations, the existing netting agreements have been taken into account in both the current and the new fee structure.

The system fee for the new fee structure is energy-based. Thus, it puts the same strain on different forms of production per unit of energy produced. If the fee were power-based, it would be collected proportionately more from power plants with a low peak operating time - for example, solar power.

Since, based on the assumptions used in the impact assessment, the generation capacity fee for power plants and the energy fee for short operating time power plants are the same in the new and current fee structure, and the impact of the new loss fee is approximately the same as the effect of the current main grid input fee, it means that all production will be subject to an additional cost in the new fee structure, which roughly corresponds to the amount of the system fee (0.39 €/MWh). In the current fee structure, the system costs are mainly covered by consumption fees that are targeted only at consuming customers.

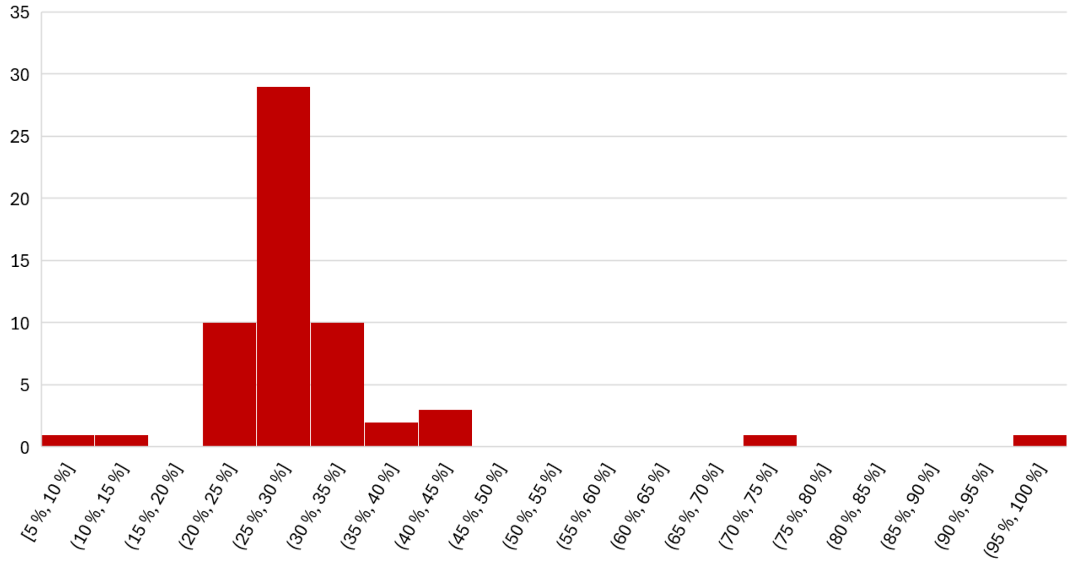

Figure 4.6. Distribution of percentage changes of the producers. The y-axis indicates the number of customers that fall within each percentage change interval.

4.3 Industry

The total fees of industrial customers is reduced by 7%. The distribution by customer is shown in Figure 4.7. For most industry customers, the fees are reduced by 0–20%. The fees are reduced for approximately 70% of industrial customers. The fees increase for the industrial customers with high withdrawal power in relation to energy consumption, i.e., customers with low capacity factor (see Figure 4.8).

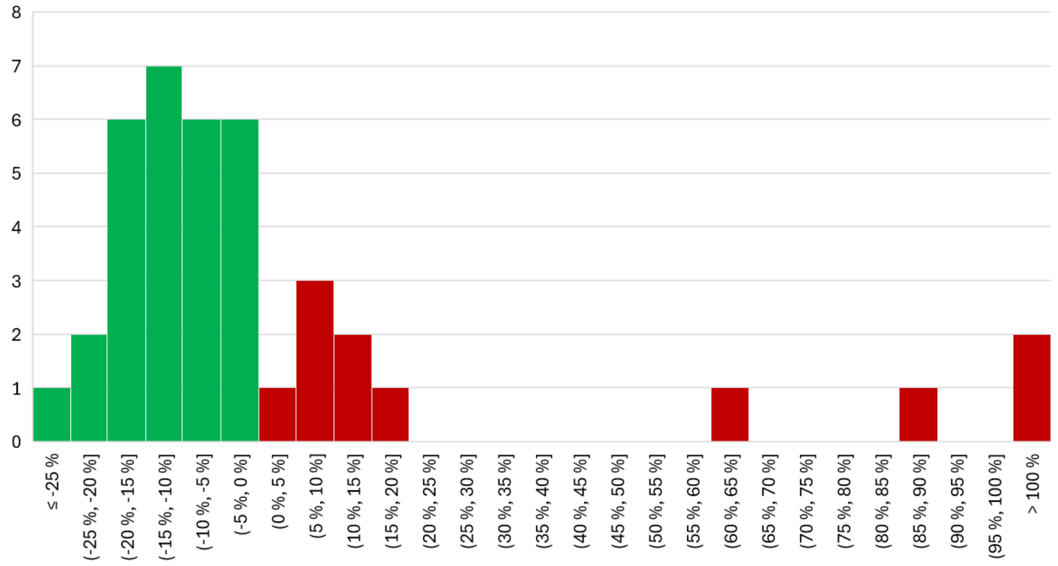

Figure 4.7. Distribution of percentage changes of industrial customers.

The changes are largely explained by the fact that in the new fee structure, the consumption capacity fee is the most significant payment component, while in the current fee structure, consumption fees are the most significant factors. When moving from an energy-based fee structure to a capacity-based fee structure, the capacity factor explains a significant part of the change. In addition, generation behind the connection can decrease loss fee and possibly consumption capacity fee, if the production is available during peak consumption.

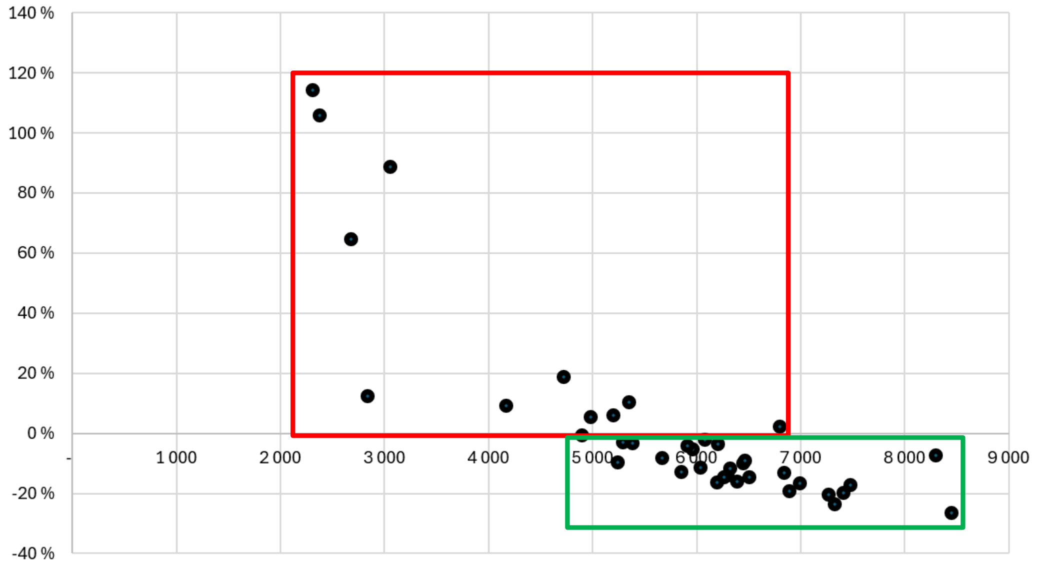

Figure 4.8. Percentage changes in industrial customers' payments as a function of the capacity factor (= annual energy consumption / the withdrawal power on the basis of which the consumption capacity fee is paid).

4.4 DSOs and others

The total fees of DSOs and others are reduced by 5%. The client-specific distribution is shown in Figure 4.9. The fees decrease for about half of the customers and increase for half of the customers. Apart from one DSO, the changes are between -20% and +20%. Changes outside this range target other consumption customers who are not industrial in nature, but of which there were too few to form a separate customer group.

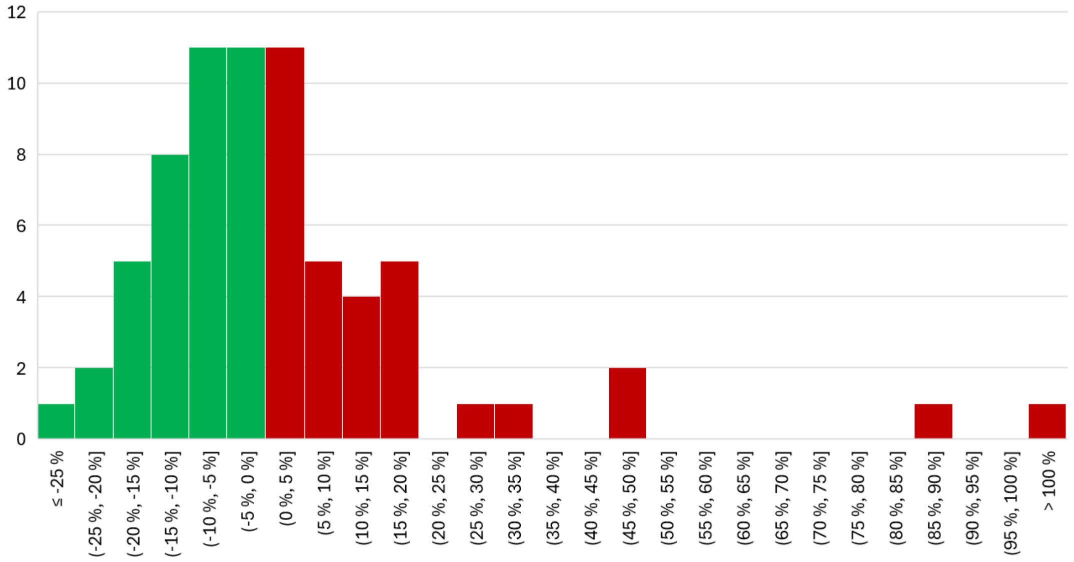

Figure 4.9. Distribution of percentage changes of DSOs and other customers.

The reform benefits customers with a high capacity factor (see Figure 4.10) and generation behind the connection point, i.e., for example urban DSOs with a significant amount of combined heat and power production. Beneficiaries can also be found in the distribution networks of sparsely populated areas, which have a significant amount of production. Fees increases in distribution networks, where the capacity factor remains low due to, e.g., the large share of electric heating customers, power peaks caused by electric boilers and the lack of production.

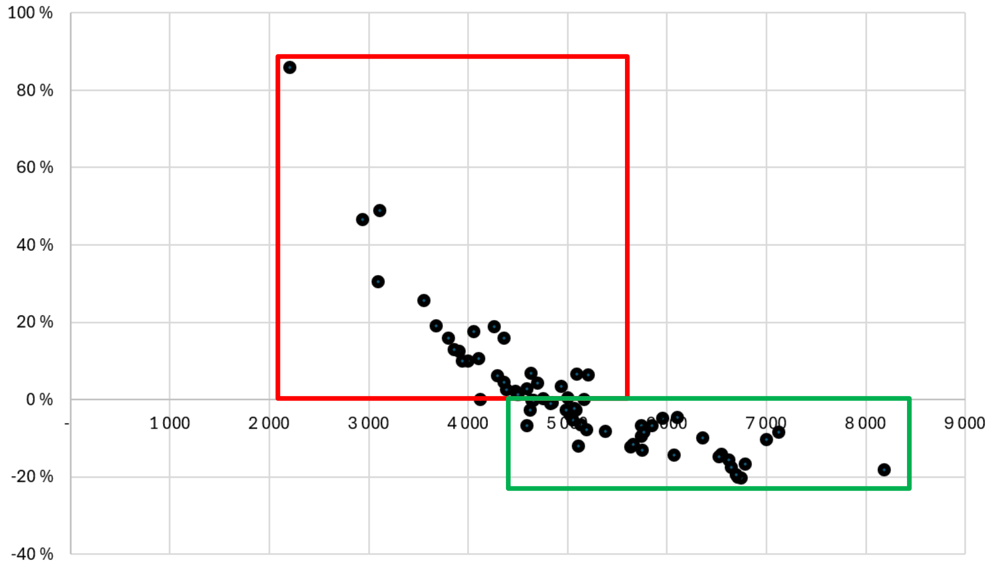

Figure 4.10. The percentage change of DSOs' and other customers' payments as a function of the capacity factor.

4.5 Energy Storages

In 2024, there were not yet enough energy storage facilities connected to the main grid to carry out a proper analysis. Only one energy storage facility connected to the main grid was in use throughout the year and the other two only for part of the year. For this reason, the impacts on energy storage have been assessed using separate calculations and are not based on measured data.

The capacity fee for energy storage facilities introduced at the beginning of 2026. It was initially set to correspond to the generation capacity fee of power plants so that it is half of that fee, and it is charged separately for both input and output capacity. The most significant change in the new fee structure is that the current energy storage capacity fee will be replaced by a consumption capacity fee, because energy storage facilities reserve power based on their charging power in the same way as consumption customers. Since the consumption capacity fee is about 8 times higher than the generation capacity fee (see page 8), this change means a significant increase in fees for energy storages.

The significance of loss fee and system fee depends on the activity of the use of the energy storage. The more energy storage is charged (withdrawal from the main grid) and discharged (input into the main grid), the higher the loss fee. Similarly, the activity of use causes losses, based on which the system fee is determined. The more energy storage is used, the greater the significance of these fees. However, the consumption capacity fee is the most significant payment component, even if the energy storage is actively used.

As an example, consider a 100 MWh energy storage with a nominal output of 100 MW. Assume that the energy storage facility uses a charging power of 100 MW at its nominal capacity for at least one hour at least once in each month and that the energy storage facility is used in such a way that it charges and discharges the storage facility on average once a day (=365 cycles per year). In addition, suppose that the efficiency of the energy storage is 90%. In this case, the fees for energy storage in the new fee structure will be more than 5 times higher than in the current fee structure calculated at 2026 prices.

If the energy storage facility were used in such a way that its charging capacity from the main grid would be limited, but the discharging power would be kept at its maximum, a significant benefit in fees could be achieved. For example, if the charging capacity from the main grid were limited to 20 MW, the fees would then increase by 23% compared to the current fee structure calculated at 2026 prices. If the energy storage facility were placed in connection with production and it was not charged from the main grid at all, the fees would be lower than at present.

In addition to the above, it should also be noted that when switching from the current hourly billing period to a 15-minute billing period, it will increase the fees for energy storage facilities that are charged and discharged within the same hour.

4.6 Alternative analysis: Regional loss fee

The purpose of the regional loss fee is to charge a higher loss fee for the input energy of the production-dominant area and the output energy of the consumption-dominant area. This creates an incentive for new production to be in a consumption-dominant and balanced area and for consumption to be in a production-dominant and balanced area, which can curb the growth of network losses. At the same time, however, it should be noted that a higher loss fee is also applied to the input energy of existing production in the production-dominant area and to the output energy of existing consumption in the consumption-dominant area.

In the following, we have examined a scenario in which the loss fee is 1.5 times higher for input energy in the production-dominant area and for output energy in the consumption-dominant area. As the amount of money collected with the loss fee does not change, this means that the loss fees for customers in other areas is reduced by the corresponding amount that is charged with the increased loss fees.

This scenario increases the payments of producers located in production-dominant areas by an average of 5 percentage points and decreases the payments of producers in other areas by an average of 13 percentage points compared to the baseline scenario (= no regional loss fee). Most producers are in production-dominant areas, which explains why the percentage changes in the beneficiaries are greater than those of the losers. The increase in fees for industrial customers and DSOs located in consumption-dominant areas is both an average of 1 percentage point. Correspondingly, the fees of industrial customers located in other regions will decrease by an average of 2 percentage points and those of DSOs by an average of 3 percentage points.

The regional loss fee affects producers the most, because the relative amount of the loss fee is the greatest for them. Figure 4.11 shows the customer-specific changes for producers compared to the baseline scenario. Most producers are in production-dominant areas. In the baseline scenario, their fees typically increase by 20-40%, and the regional loss fee typically causes them an additional fee of slightly more than 5 percentage points (see the cluster in Figure 4.11).

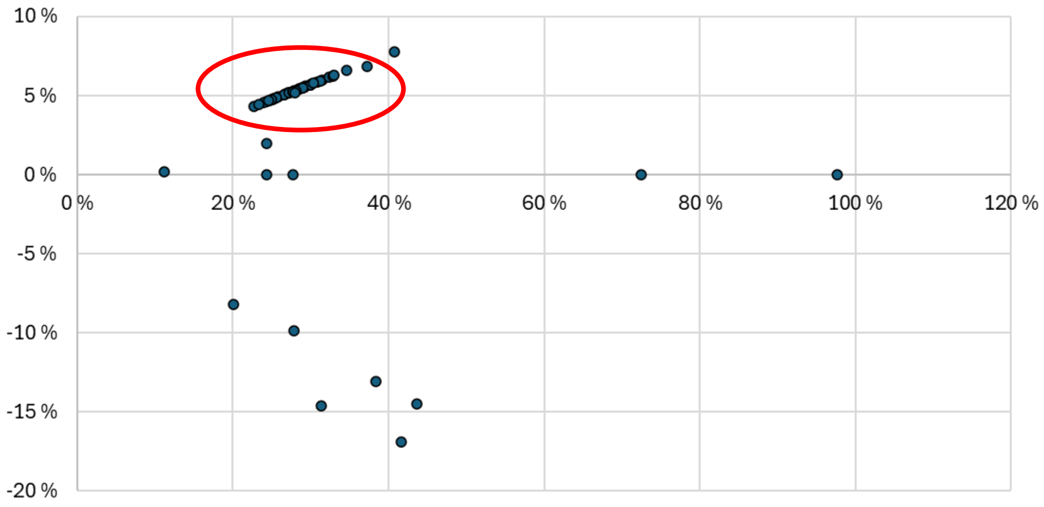

Figure 4.11. Change in producers' fees compared to the baseline scenario (= no regional loss fee) if a regional loss fee is used. In the figure, the x-axis shows the customer's change in the baseline scenario, and the y-axis shows the change in percentage points relative to the baseline scenario.

In industry and distribution networks, customer-specific changes are more moderate, as the significance of the loss fee is smaller for them. For industrial customers and DSOs, the changes are between -4 and +2 percentage points.

The effect of the regional loss fee depends on the extent to which the loss fee has an overall impact on the customer's payments. For producers, the regional differentiation is most significant, as the loss fee is about a third of the total fees of the producers. For industrial customers and DSOs, the share of the loss fee is clearly lower than this. For energy storage facilities, the significance of the loss fee depends on how actively the storage is being charged and discharged. As the consumption capacity fee is the most significant payment component, the effect of the regional loss fee is like that of consumption sites (industry and DSOs), i.e., it is more moderate than for producers. In addition, it should be noted that energy storage facilities have both output from the main grid and input into the main grid, so if, for example, output is more expensive due to the regional loss fee, the input is correspondingly cheaper – and vice versa.

Although the regional loss fee can to some extent encourage new customers to locate in favourable areas, the regional loss fee also affects existing customers. If we were like to encourage new connections to select their location in favourable areas, a regional connection fee could be a better way to achieve this than a regional loss fee.

4.7 Alternative analysis: Voltage-dependent capacity fees

The voltage-dependent capacity fee can be justified by the fact that less network infrastructure is needed for connections with a higher voltage level (400 kV) than for connections with lower voltage levels (110 kV, 220 kV).

An alternative scenario has been examined below, in which the capacity fees for a 400 kV connection would be 75% of the corresponding capacity fee for 110 kV and 220 kV connections. In this scenario, the lower capacity fee is applied only for 400 kV connections.

Since there are very few 400 kV connections, this means that the benefit is focused on a few connections and the disadvantage is spread over several connections. On average, the payments of producers benefiting from voltage- dependent capacity fee will decrease by 5 percentage points compared to the baseline. At its highest, the benefit is 7 percentage points. Correspondingly, for other producers, the fees increase by an average of 3 percentage points compared to the baseline scenario. At its highest, the disadvantage is 6 percentage points.

Industrial customers have only one 400 kV connection, which means that the fee for this customer is significantly reduced. The disadvantage, on the other hand, is spread over so many customers that, on average, the increase in fees is less than 1 percentage point. There are no 400 kV connections in the distribution networks, so there are no beneficiaries for them, but the disadvantages are also less than 1 percentage point on average. At its highest, the disadvantage is 3 percentage points.

If the consumption capacity fee and generation capacity are set according to the voltage level, the fees must be determined in more detail using the principles of cost correspondence. If interest in 400 kV connections increases, it can reduce the investment pressure on the main grid by reducing the need to build 110 kV network. At the same time, grid losses in the main grid would also decrease.

5 ASSESSMENT OF THE DEVELOPMENT OF FEES

5.1 Impact of the operating environment changes on the fees

There are three essential perspectives in assessing the development of main grid service fees in the future. Firstly, it is necessary to understand how electricity production and consumption as well as power needs will change in the coming years. Secondly, it is necessary to understand what kind of changes are taking place within different customer groups and how this affects the distribution of fees between customer groups. Thirdly, it is necessary to identify what kind of changes are taking place at the level of individual customers.

First, we will examine the most significant changes in the operating environment, i.e. (i) how electricity production and consumption will change, (ii) how the power and energy taken from and fed into the main grid is estimated to develop, and (iii) what kind of investments are planned to be made in the main grid. Based on this information, the aim is to estimate how the different components of the new fee structure will develop by the early 2030s.

Fingrid has estimated that by the early 2030s, electricity production and consumption will grow from a level of about 80 TWh/year to a level of about 120 TWh/year[1], i.e., increasing about 50%. The consumption peak power is estimated to increase from a level of about 15 GW to a level of about 23 GW, i.e., slightly over 50%. The power plant capacity is estimated to increase from a level of about 20 GW to a level of about 33 GW, i.e., increasing about 65%.

The amount of power taken from the main grid is estimated to increase slightly more than the consumption peak power. Similarly, the power supplied to the main grid is estimated to grow slightly more than the production peak power.

The amount of energy taken from the main grid and the amount of energy injected into the main grid is also estimated to grow relatively faster than production and consumption, as production and consumption are differentiated geographically. This means that the use of the main grid in the electricity system will also increase in relative terms.

In the following, we will examine how the change in the operating environment affects the different components of the new fee structure. First, let's examine the development of the consumption capacity fee (€/MW, month). It is affected by the costs of the network infrastructure and the development of the power taken from the main grid. The development of network infrastructure costs can be assessed based on the development of the capital invested in the main grid and the reasonable return on it, as well as the straight-line depreciation calculated from the replacement value of the grid. In 2024, the reasonable return on capital invested in the main grid (3,617 M€) was 241 M€ and the straight-line depreciation was 120 M€[2]. In total, these amounted to 361 M€. Fingrid has estimated that it will make investments of approximately 2,000 M€ in 2026–2029[1], of which approximately 80% will be new investments and 20% replacement investments[3]. Investments increase the value of the network, but at the same time, the network also ages, which reduces the net present value of the current network. Overall, it can be roughly estimated that at the above-mentioned investment rate, the capital invested in the main grid is likely to exceed 5,000 M€ in the early 2030s.

[1] Fingrid, Fingrid' main grid development plan 2026-2035

[2] Energy Authority: Hinnoittelun valvonta | Energiavirasto [in Finnish]

[3] Fingrid, Fingrid's main development plan 2024-2033

If the calculation of the reasonable return is based on the same rate of return as in 2024 (6.67%), it means that the costs of network infrastructure will increase in proportion to the capital invested in the network. This means roughly a 40% increase in grid infrastructure costs covered mainly by the consumption capacity fee. If the consumption capacity develops as described earlier (an increase of slightly over 50%) and the costs of the network infrastructure increase by about 40%, this means a small decrease in the unit costs of the consumption capacity fee. On the other hand, if the increase in consumption capacity is lower than the estimated increase in network infrastructure costs (40%), it will lead to a higher unit cost.[1]

The unit cost of the loss fee (€/MWh) is affected by the cost of energy losses and the amount of energy taken from the main grid and fed into the main grid. Fingrid has estimated that grid losses will increase significantly as production and consumption diverge geographically. Although the energy taken from the main grid and the energy supplied to the main grid are expected to increase by more than 50%, the unit cost of the loss fee may increase in the future.

The unit cost of the system fee (€/MWh) depends on the development of system costs and the amount of electricity production and consumption. Fingrid has estimated that system costs will increase relatively moderately by the early 2030s. If production and consumption increase by about 50%, the unit cost of the system fee could decrease.

[1] As congestion income was used significantly in 2024 to reduce main grid service fees, this means that the unit costs presented in this report cannot be used as such to estimate future unit costs. This concerns all payment components.

When looking at the development of different customer groups and, a significant change is the increase in energy storage facilities in the electricity system. As a result, energy storage facilities will contribute to the payment of grid service fees in the future with a larger share than at present. In 2024, the share of energy storage was still non-existent. However, the number of energy storages is growing rapidly. The development of the number of energy storage facilities and their contribution to main grid service fees are examined in more detail in Chapter 5.2.4.

Another significant change is the consumption growth due to new industrial sites and data centres.[2] Both new industrial sites and data centres have high capacity factor, which means that their payment burden per unit of energy is lower than the average of current consumption customers. However, at the same time, they also participate in sharing the costs of the existing network infrastructure, which are charged in consumption capacity fee. In addition, they pay the loss fee and the system fee according their energy consumption. Changes in industry are examined in more detail in Chapter 5.2.2.

In addition to industry and data centres, there is an increase in consumption in distribution networks, especially as heating becomes electrified (incl. electric boilers for district heating) and electric transport increases. In addition, the development of the fees is affected by how much of the new production, energy storage facilities, data centres and industrial sites are connected to the main grid and how much to the distribution networks. Distribution networks are examined in more detail in Chapter 5.2.3.

[2] Fingrid, Fingrid' main grid development plan 2026-2035

5.2 Development by customer groups

5.2.1 Producers

Fingrid estimates that electricity production will increase by about 50% by the early 2030s in a favourable case. At the same time, the power plant capacity is estimated to increase by about 65%. The increase in power plant capacity is primarily due to wind power and solar power, both of which have a lower capacity factor than existing production capacity on average. For this reason, generation capacity is growing relatively faster than the amount of electricity produced. As a result, either the share of the grid service fees collected by the power plants will increase or, alternatively, the unit price of the generation capacity fee of the power plants can be decreased, if the share of the generation capacity fee of the total fees is kept the same. In any case, the share of wind and solar power among those paying generation capacity fees is increasing.

Loss and system fees are energy-dependent, so the burden of these fees is determined based on the energy produced (system fee) and the amount of energy supplied to the grid (loss fee). Thus, different production technologies pay the same fee per energy produced. If the new producers are located in the same connection as the consumption sites (hybrid connections), they will benefit in lower loss fees.

If a regional loss fee is introduced, it will benefit new producers located in balanced and consumption-dominant areas. Similarly, if a voltage-dependent generation capacity fee is introduced, it is likely to increase the demand for 400 kV connections.

5.2.2 Industry

Industrial and data centre consumption is projected to grow significantly by the early 2030s. Now, more than half of the industrial plants are connected to the main grid, but a significant number have connected to the distribution networks. As such, the main grid pricing principles of industry and distribution networks are the same, but differences arise in some distribution networks in which there is a lot of production and thus occasional supply to the main grid. In this case, new industrial consumption sites may in some cases reduce the input to the main grid. The optimal location for new industrial sites and data centres will also depend on fees used by DSOs. Chapter 6.3 examines in more detail the conditions for DSOs to pass the main grid fee structure to their own customers.

The power consumption of data centres is quite steady, so their consumption capacity fees can be assumed to be the same throughout the year, even though half of the consumption capacity fee is based on the hourly peak of each month. Due to the high capacity factor, the consumption capacity fees of data centres per unit of energy remain lower than on average. On the other hand, because data centres consume a lot of energy, their share of system fee increase significantly. Similarly, at the system level, they significantly increase withdrawals from the main grid, regardless of whether they are connected to the main grid or the distribution grid, which increases their share as payers of loss fee. The same analysis applies to industrial plants with a relatively stable consumption profile throughout the year and a high capacity factor.

5.2.3 DSOs

By the early 2030s, there will be significant changes in distribution networks. The changes will depend on the location and amount of the new electricity production and consumption, the growth rate of electricity consumption in general and the removal rate of the current electricity production capacity.

Particularly significant changes will take place in distribution networks where combined heat and power production is replaced by electric boilers. Electric boilers will significantly increase the power and energy taken from the main grid as well as the consumption behind the connection point. A change in the power taken from the main grid affects the consumption capacity fee, a change in the amount of energy taken from the main grid affects the loss fee, and a change in the consumption behind the connection point affects the system fee.

Some urban distribution networks are undergoing major changes as combined heat and power production decreases, the number of electric boilers increases, and electricity consumption increases as industry and transport become electrified. For example, Helen Sähköverkot has estimated that Helsinki's electricity consumption may double by 2030[1]. If, at the same time, combined heat and power production continues to decrease, it may significantly increase the power and energy taken from the main grid. Thus, the new main grid fee structure, which, calculated based on 2024 data, benefits urban distribution network operators with significant combined heat and power production, may lead to an increase in fees in urban distribution networks in the longer term - especially if combined heat and power production is significantly replaced by electric boilers.

[1] Helen sähköverkko, Item of news, 18.12.2025 [in Finnish]

The electrification of transport is likely to proceed in such a way that the share of electric cars will first increase in urban areas, and thus, increase electricity consumption in urban distribution networks. The effect on the consumption capacity fee depends on the timing of the charging. Currently, most electric car owners schedule charging based on electricity spot price, which is cheaper typically at nights, when consumption is lower than average. Thus, it does not cause an increase in the consumption capacity fee. In the longer term, however, the electrification of heating (including district heating) and the increase in energy storages, together with the charging of electric cars, may lead to power peaks at night.

In distribution networks, in which new electricity production (e.g., solar or wind power) is connected to distribution grid, the amount of energy taken from the main grid decreases. If production is high, the input to the main grid will also increase. The effect on the consumption capacity fee is likely to be small, as the production of variable wind and solar power does not necessarily coincide with the moments when the withdrawal from the main grid is at its highest.

If a DSO introduces capacity fee based products for its customers with a fuse size of less than 63 A and also increases the share of the capacity fee also for its larger customers, it may have a notable impact on the consumption capacity fee paid by the DSO. On the other hand, if a DSO does not introduce the capacity fee for small customers and does not increase the share of the capacity fee for its larger customers, it may lead to increase in the power taken from the main grid, and thus, higher consumption capacity fee. The ability of DSOs to pass on capacity fees to their own customers is examined in more detail in Chapter 6.3.

5.2.4. Energy Storages

The number of energy storage will increase significantly in the future. In 2024, the energy storage capacity connected to the main grid was 0.05 GW. In May 2026, the total capacity of energy storage facilities, including electricity storage facilities of more than 1 MW connected to both the transmission and distribution grids, was already 1,367 GW[1]. This corresponds to about 7% of peak power capacity of the whole electricity system.

Fingrid has estimated that energy storages could increase by about 1 GW for every 10 TWh increase in consumption.[2] In this case, the assumed increase in consumption of 40 TWh by the early 2030s would increase energy storage capacity by about 4 GW. In this case, the share of energy storages of consumption capacity fee could already be considerable; slightly over 20%. This would reduce the payment burden of industry and DSOs correspondingly.

The consumption capacity fee is the most important factor for energy storages. For this reason, it is essential how efficiently the energy storage facilities connected to the main grid can adjust their charging power. The energy storages that charge at partial power can get significantly lower fees than those that charge at full power. Similarly, energy storage facilities connected with production (= hybrid connections) can get significantly lower capacity fees when charging is scheduled according to production. Thus, the introduction of consumption capacity fee encourages new energy storage facilities to be located in connection with production.

In addition to the consumption capacity fee, it should be noted that if energy storage facilities are actively used, the significance of loss fee and system fee increases, because each charge-discharge cycle causes a cost that is twice the amount of the loss fee plus the system service fee, which is based on the losses of the energy storage. Based on the unit prices of the new fee structure formed with data from 2024, the cost of one charge-discharge cycle is 1.28 €/MWh, if the efficiency of the energy storage facility is assumed to be 90%. Calculated according to the fee structure and unit prices in force in 2024, the corresponding cost of one charge-discharge cycle is 1.62 €/MWh, which consists of the sum of the main grid output fee (1.1 x €0.92/MWh, considering 10% loss) and the main grid input fee (€0.61/MWh).

[1] Fingrid, open data, Download datasets

[2] Fingrid, Neuvottelukunta 6.-7.5.2026 Presentation [in Finnish]

6 SPECIFIC ISSUES

6.1 Flexibility for consumption customers

One of the key objectives of the reform of the main grid service fee structure is to curb the amount of power taken from the main grid with the help of the consumption capacity fee and, consequently, the need to invest in the main grid. In the following, we have examined the flexibility opportunities of consumption customers based on the metering data of eight different customers. The measurements are from 2024, with an accuracy of 15 minutes. Four of the customers under review are DSOs and four are industrial sites. Two of the DSOs are urban DSOs, one of which has production and the other does not. Similarly, one of the rural DSOs has production and the other does not.

The characteristics describing the customers under review are compared in Table 6.1. Customers differ significantly in terms of main grid withdrawal and consumption as well as the capacity factor. There is a clear difference in the capacity factor of urban and rural DSOs, which is explained, e.g., by the larger share of electric heated customers in rural DSOs. There are also major differences in industrial customers, which are due to, among other things, the different energy and power needs of the processes of different industries.

When assessing the flexibility opportunities and the capacity to shave peak power, it is possible to examine how many hours per year the customer's power exceeds 90% of the annual peak power (see Table 6.1). This makes it possible to estimate customers' opportunities to reduce the annual peak power by 10%.

In the examined DSOs, the number of hours when 90% of the annual peak power is exceeded varies between 31 and 115 hours, while in industrial sites the differences are clearly larger (3–1009 hours). Indicatively, it can be estimated that several DSOs, and at least some industrial sites, could have reasonably good opportunities to reduce the annual peak power. Short-term peak shaving can be made by reducing consumption or by shifting load to a more favourable time. Also, short-term peak power can be levelled by using energy storages, while a longer-term levelling will probably require new production behind the connection point.

Table 6.1. Comparison of the characteristics of the selected customers based on measurements in 2024.

Customer	Energy from the main grid (MWh) / Consumption (MWh), %	Annual energy consumption (MWh) / Annual hourly peak power (MW), h	Hourly power higher than 90 % of the annual hourly peak power, h
DSO, Urban 1	88 %	5 232	115
DSO, Urban 2	100 %	4 940	108
DSO, Rural 1	100 %	2 879	72
DSO, Rural 2	58 %	3 465	31
Industry A	100 %	5 883	1 009
Industry B	92 %	4 783	435
Industry C	34 %	1 519	180
Industry D	52 %	3 434	3

Let's take a closer look at the annual power peaks of four sites. Figure 6.1 shows the peak power of rural DSO 1. It takes place in the evening of a cold winter day (5th January at 23:00-23:15), when the night-time electricity of time-tariff customers is likely to be switched on, and some customers are likely to prepare for the next day's record-high spot prices by heating their homes in advance[1]. By balancing the peak power (duration approx. 2 hours, which repeats daily), a decrease in the main grid withdrawal power could be about 5%.

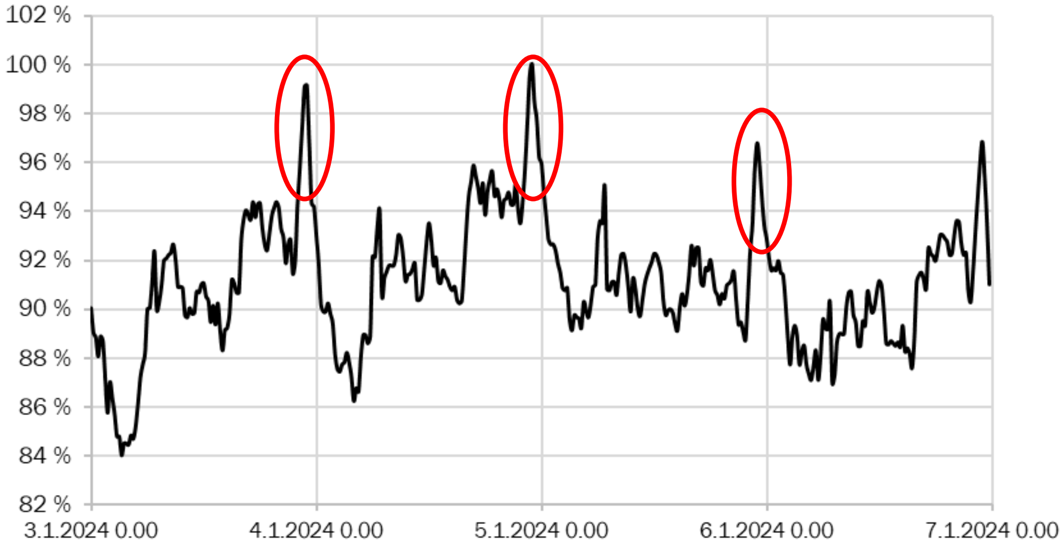

Figure 6.1. Annual power peak of a rural DSO (15 min measurement).

[1] The next day (5.1.2024), the average price of exchange electricity was at a record high of over €1/kWh, when e.g., Government urges citizens to save electricity, Press release [In Finnish]

Figure 6.2 shows the power peak of the urban DSO 1 (26 January at 16:45-17:00). At this case, the power peaks seem to occur in the late afternoon, and they last longer than in the case of the rural DSO, where the balancing of power peaks could be done, e.g., by optimising the night-time electricity control commands and the use of domestic hot water heaters. Balancing the power peaks of this urban DSO would require the use of energy storage facilities or power limitation agreements with some customers. Also, capacity fees for DSOs' own customers can also be used to promote power management.

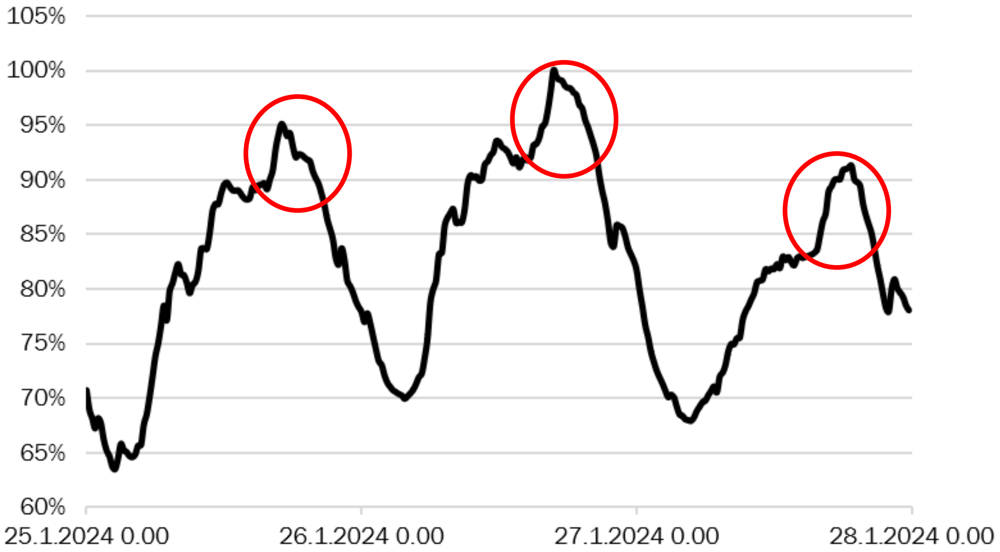

Figure 6.2. Annual power peak of the urban DSO (15 min measurement).

Figure 6.3 shows the annual power peak of industrial site B. Without knowing the details of the industrial site's process, it is difficult to assess whether it would be possible to balance consumption at this site, and thus, reduce the peak power. With an energy storage, it would be possible to balance consumption to some extent, but even with it, the savings would remain at roughly 5% level.

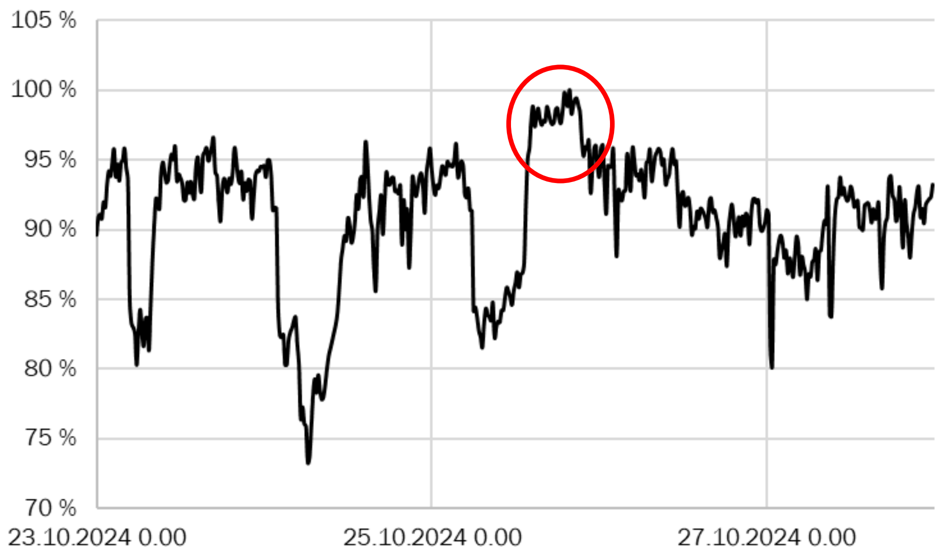

Figure 6.3. Annual power peak of industrial site B (15 min measurement).

Figure 6.4 shows industrial site C, where a few similar peak power situations occur during the year. In this case, the main grid withdrawal power rises suddenly and recovers slowly. The power is over 80% of peak power for about a day and over 60% for a couple of days. If we wanted to balance the peak power of this site, we would need a very large energy storage or own production behind the connection point – or backup power, if the power peak is caused by the sudden shutdown of own power plant.

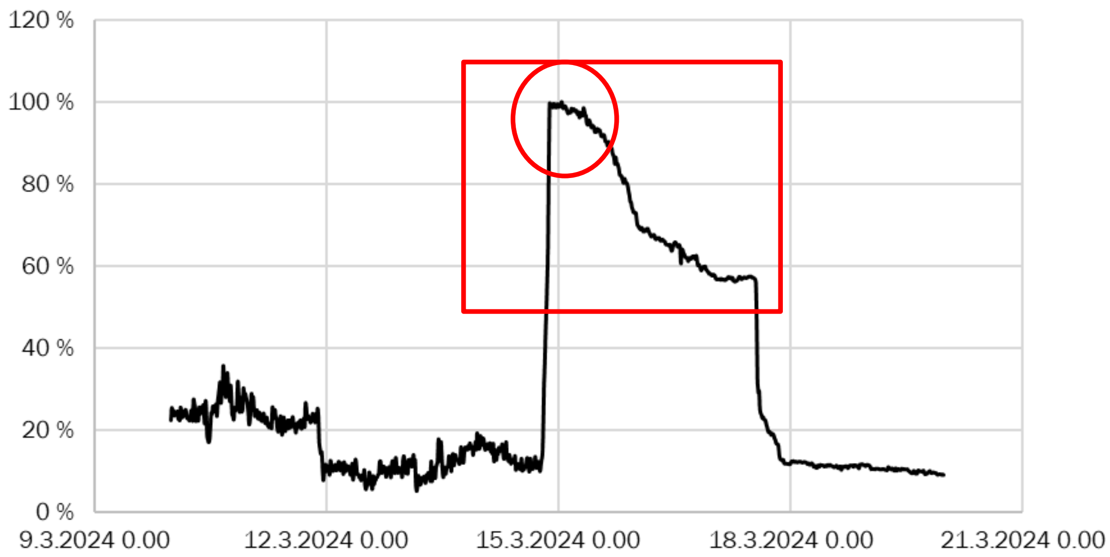

Figure 6.4. The annual power peak of industrial site C (15 min measurement).

Based on the analyses of DSOs, it can be concluded that DSOs differ from each other, but in general, they can implement flexibility solutions and thus reduce power withdrawn from the main grid by e.g., the following means:

1. By optimising the settings of the controllable loads so that power peaks are levelled, e.g., by adjusting the use of domestic hot water heaters
2. By utilising capacity fees for their own customers
3. By making power limiting contracts, e.g., with large consumption customers or aggregated small customers
4. By using energy storages to level power peaks, e.g., as purchased services

Because the DSOs do not participate in the electricity market other than by purchasing energy losses, the market price of electricity does not steer them in the same way as, for example, industrial customers. Thus, DSOs can focus on limiting the main grid withdrawal power almost regardless of the market price of electricity, and thus, reduce their own costs in the new fee structure.

It should be noted that in the current supervising model for DSOs, they do not benefit from lower main grid costs, but the benefits go to the end-customers in full. However, the costs incurred from the implementation of flexibility can be deducted (at least partially) based on the flexibility incentive, but DSOs do not receive any direct benefit from this. The implementation of flexibility solutions could be promoted compared to the current situation, if the DSOs could also benefit financially from the implementation of flexibility solutions.

Industrial sites differ from each other more than DSOs, and thus their ability to implement flexible solutions differs significantly from each other. On a general level, flexibility solutions can be implemented in industry in the following ways:

1. By optimising processes and scheduling electricity consumption at favourable times
2. By utilising energy storages (behind the connection point)
3. By increasing electricity production behind the connection point and/or implementing hybrid solutions

According to a study commissioned by Helen from Afry, the flexibility potential of selected energy-intensive industries is currently 1.2 GW, which corresponds to 18% of the peak capacity in accordance with current consumption. It should be noted that in industry, the incentive for flexibility arises from the fluctuating market price of electricity, and thus the implementation of flexibility is primarily motivated by the optimisation of the procurement costs of electrical energy. Of course, the same flexibility solutions can be used to optimise both electricity procurement and main grid withdrawal power. During a period of high electricity market prices, benefits can be achieved in both. A conflict situation may arise during the period of low electricity market price.

In summary, it can be stated that the consumption customers of the main grid can implement flexibility solutions, and thus, reduce the power withdrawn from main grid. The reform of the fee structure would probably increase the demand for energy storages and smart control systems, as well as power limiting contracts.

[1] Helen, study reported 10.12.2025: Summary of the study, [in Finnish]

6.2 Location of new projects

The new fee structure includes the following cost-based elements that affect the location of new production and consumption:

1. The consumption capacity fee and the loss fee allocated to consumption encourage consumption customers and energy storages to be located at the same connections as production.
2. The loss fee encourages production to be located at the same connections as consumption.
3. By applying regional loss fee, production can be further encouraged to be located in a consumption-dominant or balanced area and consumption in a production-dominant or balanced area.
4. By applying voltage-dependent capacity fee, both production and consumption can be encouraged to connect to the 400 kV network.

First, let's look at the new consumption customers of the main grid, which include data centers and clean transition industrial plants (including hydrogen plants). Because the fees of consumption sites are dominated by the consumption capacity fee, it also has the greatest incentive on location. This means that in terms of location, it is most advantageous to connect to the same connection as production and/or energy storage (= hybrid connection). However, it would be necessary for the production technology to be such that production would be available during consumption peaks, which is not guaranteed by weather-dependent wind and solar power (if not combined with energy storage). One possibility would be flexible engine power plants.

Although wind and solar power do not necessarily produce during consumption peaks, hybrid connections reduce input and output energy to and from main grid and generate savings due to a lower loss fee. If the loss fee is set according to the area, the benefits of hybrid connections will be greater in these areas

If the voltage-dependent capacity fee is implemented with even a reasonable price difference, it encourages the use of one 400 kV connection instead of two 110 kV connections. Although a 400 kV connection will be more expensive in connection fees (in 2026: a 400 kV connection costs 2.5 M€ and a 110 kV connection 1.0 M€), the price difference will be compensated in short time. Large industrial sites, data centres and big urban DSOs could benefit from voltage-dependent consumption capacity fee. Since the consumption capacity fee is higher than the loss fee, this would mean that the regional loss fee would have a smaller impact in the location than the voltage level.

The location of new production sites in consumption-dominant and balanced areas would be more favourable, if the loss fee is set according to the area. If the loss fee were 50% higher in a production-dominant area than in a consumption-dominant and balanced area, it would have a significant impact on the total amount of main grid service fees for producers (see also Chapter 4.6).

6.3 Ability of the DSOs to pass on the fees to their customers

The ability of DSOs to pass on the capacity fees of the main grid to their own customers depends on the voltage level of the customers, because the share of main grid fees in the total fees varies greatly at different voltage levels. Main grid fee account for most of the fees of high-voltage customers, while the significance of main grid fee is clearly smaller for low- and medium-voltage customers.

First, let's look at the customers of high-voltage distribution networks and the impact of the annual 8% price increase cap on their pricing defined in the Electricity Market Act. For high-voltage customers, the maximum acceptable amount of the increase is calculated based on the total fee for each network user over a 12-month review period.[1] It is therefore quite possible that the fees of the new fee structure cannot be passed on to individual high-voltage customers at once due to the annual 8% price increase cap. In particular, there may be problems in passing on the consumption capacity fee to customers who have high peak power in relation to energy consumption and whose fees have previously been based on the DSO's fee structure, which has imitated Fingrid's current energy-based fee structure. If the consumption customer locates also in a consumption-dominant area and the new fee structure applies an increased loss fee for consumption in the consumption-dominant area, the situation is even more challenging. However, the new fee structure can also be passed for such customers, but it will take place over a period of more than one year.

In most high-voltage distribution networks, it will take several years to pass the main grid consumption capacity fee to energy storage facilities, because the consumption capacity fee under the new fee structure would significantly increase the fees for energy storages (see Chapter 4.5). Similarly, in the case of production connected to the high-voltage distribution network, the price increase would typically have to be made over several years to be able to collect the costs of the new fee structure from the producers in full. Roughly speaking, the main grid's system fee increases the costs of producers about 30%, and even if the pricing of a high-voltage distribution network is more expensive than that of the main grid, the annual price increase cap of 8% will be met in many cases.

For consumption customers in the low and medium voltage grid, the increase cap is not as big a problem, as the share of main grid fees in the total price is lower. Especially in the low-voltage network, the share of main grid fee and regional network fees in the total taxable fee is typically less than 10%. Thus, for example, in the few distribution networks where main grid service fees would increase by as much as 20% (see Chapter 4.4), the impact on low-voltage customers would remain at the level of a couple of per cent.

In addition, it should be noted that in the low- and medium-voltage network, the assessment of the price increase cap is made based on *representative customers* and not based on individual customers. In this case, the question is rather how the DSOs manage to create such fee products for their customers that their low and medium voltage customers choose the product that includes the capacity fee.

[1] Electricity Market Act, 588/2013, Finlex [in Finnish]

[2] Energy Authority, Sähkönjakelupalvelutuotteiden maksukomponenttien määräytymisperusteiden tarkentava soveltamisohje, 14.4.2026, Dnro 2340/000002/2025 [in Finnish]

According to the Energy Authority's guidance, capacity-free fee alternative must also be offered to customers that have a main fuse with a maximum of 63 A[1]. In practice, this means that DSOs must be able to form their capacity fee products in such a way that they are a cheaper option for customers who consume a threshold power of more than 8 kW than a product without a capacity fee, and also, be able to demonstrate to their customers that they should choose a capacity fee product.

Regarding low- and medium-voltage network producers and energy storages, the Energy Authority has not published, at least for the time being, *representative consumers,* based on which the price increase cap would be monitored. For this reason, it is not possible to estimate with certainty how the new main grid fees could be passed for energy storage facilities and producers over 1 MW connected to the low- and medium-voltage distribution network.

In summary, it can be stated that the annual price increase cap regulation slows down the implementation of fee structure changes that improve cost correspondence. If the costs cannot be allocated in a cost-corresponding manner, some of the DSO's customers will have to pay the costs caused by others. If, for example, the changes cannot be allocated to the customers of the high-voltage distribution network, there is a risk that the payment burden will fall on the same DSO's low- and medium-voltage network customers.

[1] Energy Authority, Sähkönjakelupalvelutuotteiden maksukomponenttien määräytymisperusteiden tarkentava soveltamisohje, 14.4.2026, Dnro 2340/000002/2025 [in Finnish].

7 CONCLUSIONS

Fingrid aims to achieve a cost-based main grid service fee structure in which the fees are allocated to customers in accordance with the causality principle. The aim of the reform is to curb the growth of the power taken from the main grid and fed into the main grid to avoid unnecessarily large main grid investments. In addition, the reform will encourage new connections to select their locations so that they are favourable to the main grid, which will reduce the amount of energy transmitted in the main grid and thus also network losses.

The fee reform will change the distribution of costs between customer groups. Based on calculations made with data from 2024, producers' share of the total fees increases from 13% to 17%. Correspondingly, the share of industrial customers decreases from 21% to 19%, and the share of DSOs and other consumption customers decreases from 67% to 63%. Because there are also power plants in industrial sites and distribution networks that pay the generation capacity fee, the energy fee for short operating times power plants, as well as the loss fee for input to the main grid and the system fee for net production, the total share of production in the new fee structure increases to 26%. In the current fee structure, the total share of production is 19%.

The total fees of producers increase by 33%. In euros, this means an additional cost of about 0.4 €/MWh. For most producers, the increase is between 20% and 45%. The new system fee is energy-based, which means that it burdens different production technologies by the same amount per unit of energy produced. At the same time, it means that relatively more system fees are collected from power plants with a high capacity factor.

The total fees of industrial customers decreases by 7%. For most of industrial customers, the fees decrease by 0–20%. The fees is decreased for approximately 70% of industrial customers. The fees increase for those customers who have a high peak power in relation to energy consumption, i.e., a low capacity factor. For a few customers who have large power peaks in relation to consumption, the fees increase significantly – even more than double.

The total fees of DSOs and other unclassified consumption customers decreases by 5%. The fees decrease for about half of the customers and increase for half of the customers. Apart from one DSO, the changes are between -20% and +20%. The fee reform benefits customers who have high capacity factor and production behind the connection point, i.e., urban DSOs with significant amount of combined heat and power production. Beneficiaries can also be found in the DSOs of sparsely populated areas, which have a significant amount of production in their grid. Fees, on the other hand, increases for DSOs, in which capacity factor is low, e.g., due to the high share of electric heating customers, power peaks of electric boilers and low production.

Regarding energy storages, the most significant change is the replacement of the energy storage capacity fee with the consumption capacity fee. So far, no consumption-based fee has been levied on energy storage facilities, and thus, they have not fully contributed to the payment of the costs of the network infrastructure. As the consumption capacity fee is about 8 times higher than the generation capacity fee, this means significantly higher fees for energy storage facilities than at present. If an energy storage facility limits its charging capacity or locates in connection with production, it can significantly reduce its costs.

The calculations made in this impact assessment are based on the data from 2024. Since then, there have been many changes in both the electricity system and the customer base. When the new fee structure will be introduced (preliminarily 1 January 2029), the situation will differ significantly from the situation in 2024, and more changes are expected until the early 2030s.

Fingrid has estimated that by the early 2030s, electricity production and consumption will grow from about 80 TWh/year to about 120 TWh/year, i.e., increasing about 50%. The consumption peak power is estimated to increase from a level of about 15 GW to a level of about 23 GW, i.e., slightly over 50%. The generation capacity is estimated to increase from a level of about 20 GW to a level of about 33 GW, i.e., increasing about 65%. At the same time, the amount of power taken from the main grid is estimated to increase slightly more in than the consumption peak power. The amount of energy taken from the main grid and the amount of energy fed into the main grid is also estimated to grow more than production and consumption. This means that the use of the main grid in the electricity system will also increase in relative terms.

The costs of the grid infrastructure that mainly determine the consumption capacity fee are estimated to increase at roughly the same pace as main grid withdrawal power, so the unit cost of the consumption capacity fee can be estimated to remain at roughly the same level. The power plant capacity, on the other hand, is estimated to grow faster than the input power to the main grid, in which case the share of the generation capacity fees collected by the power plants will increase, or alternatively, the unit price of the generation capacity fee can be decreased, if the share of generation capacity fee of the total fees is kept same.

Fingrid has estimated that main grid losses will increase significantly as production and consumption diverge geographically. Although the energy taken from the main grid and the energy supplied to the main grid are expected to increase by more than 50%, the unit cost of the loss fee may increase in the future. In terms of system costs, Fingrid has estimated that they will increase relatively moderately by the early 2030s. If, according to a favourable forecast, production and consumption increase by 50%, the unit cost of the system fee may decrease with this development.

When examining the development of different customer groups until the early 2030s, the following significant changes can be highlighted:

- The share of wind and solar power paying generation capacity fees is increasing.
- The increase in energy storage facilities in the electricity system and the allocation of the consumption capacity fee to energy storage facilities mean that they will participate in the payment of grid service fees in the future with a larger share than at present.
- As consumption growth is focused on industry and data centres with high capacity factor, their payment burden per unit of energy is lower than the average for current consumption customers. However, they also contribute to sharing the costs of the existing network infrastructure.
- In DSOs, where combined heat and power production is replaced by electric boilers and where electric transport is growing rapidly, grid fees will rise as consumption and withdrawal from the main grid increase. The development of the consumption capacity fee is affected by how well the DSOs can encourage their customers to limit power peaks.

The consumption capacity fee creates an incentive for consumption customers to reduce the power taken from the main grid. DSOs can reduce the power taken from the main grid, e.g., as follows:

- By optimising the settings of the controllable loads so that power peaks are levelled, e.g., by adjusting the use of domestic hot water heaters
- By utilising capacity fees for their own customers
- By making power limiting contracts, e.g., with large consumption customers or aggregated small customers
- By using energy storages to level power peaks, e.g., as purchased services

Correspondingly, industrial sites can reduce the power taken from the main grid, e.g., as follows:

- By optimising processes and scheduling electricity consumption at favourable times
- By utilising energy storages (behind the connection point)
- By increasing electricity production behind the connection point and/or implementing hybrid solutions.

Energy storage facilities can save significantly in the consumption capacity fee if they charge the storage at a lower power than the nominal power or connect to same connection with production sites and charge during production.

As a conclusion, there is flexibility opportunities available in the electricity system to curb grid investments and mitigate increase in capacity fees. However, the ability to implement flexible solutions varies considerably from consumer to consumer.

The new fee structure includes the following incentives for new production and consumption to select their location:

1. The consumption capacity fee and the loss fee allocated to consumption encourage consumption customers and energy storages to be located at the same connections as production.
2. The loss fee encourages production to be located at the same connections as consumption.
3. By applying regional loss fee, production can be further encouraged to be located in a consumption-dominant or balanced area and consumption in a production-dominant or balanced area.
4. By applying voltage-dependent capacity fee, both production and consumption can be encouraged to connect to the 400 kV network.

If DSOs want to effectively influence the power taken from the main grid, they must be able to pass on the costs of the new fee structure to their customers, and at the same time, create incentives to reduce peak power of their customers. This means reviewing the fees of current power tariff customers and extending the capacity fees to low-voltage customers with fuses.

Due to the 8% price increase cap, the transfer of capacity fees under the new fee structure to some customers of high-voltage distribution networks will have to be done in stages over several years. In particular, the fees for production and energy storages are in many cases subject to an increase more than the annual 8% price increase cap.

In some cases, there may also be restrictions on the medium-voltage network due to the annual 8% price increase cap. In the case of the low-voltage network, and especially for consumers, the question is rather how the DSOs manage to create such fee products for their customers that their low and medium voltage customers choose the product that includes the capacity fee. According to the Energy Authority's guidance, a capacity-free fee alternative must also be offered to customers that have a main fuse with a maximum of 63 A. In practice, this means that DSOs must be able to form their capacity fee products in such a way that they are a cheaper option for customers who consume a threshold power of more than 8 kW than a product without a capacity fee. At the same time, it must also be ensured that any price increase is below the annual 8% price increase cap, calculated for *representative customers* describing different customer groups.