REPORT GREEN ELECTRIFICATION CLEAN INDUSTRY

Capacity fee for a flexible grid: reform agenda

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Abstract

The electrification of industry is a key strategy for maintaining European Union's competitiveness and strengthening its economic, political, and military resilience. It should be carried out with maximum use of zero-emission energy sources.

In Poland, a significant barrier to electrification is the capacity fee mechanism

The current method of calculating this charge rewards a stable, "flat" energy consumption profile. At the same time, it discourages increased consumption during the hours when the capacity fee is applied (set by the Energy Regulatory Office (URE) as 7:00 a.m.–9:59 p.m. on business days). During these same hours , there is a growing oversupply of energy generated from photovoltaic sources. This results in the need to curtail production, including through non-market reallocation. In practice, therefore, some of the cheapest energy from RES is wasted. Consequently, the current model limits the economic incentives for electrification and for active energy consumption management by industry.

A properly designed capacity fee should serve as a clear price signal encouraging consumers to reduce their energy consumption during periods of capacity shortages in the power system. Such a mechanism makes it possible to limit the volume of capacity contracted on the capacity market and reduce the operating costs of the entire system. Maintaining the current model may lead to opposite effects, while simultaneously increasing the costs of reallocating renewable energy sources.

Any change to the structure of the capacity fee should take into account the realities of how the power system operates. First and foremost, it is necessary to narrow the range of hours during which the fee is calculated. These hours should correspond to actual periods of risk of power shortages in the National Power System (KSE). This approach will allow consumers to better adapt their energy consumption profiles to system conditions and respond to price signals.

It is also reasonable to consider moving away from solutions that reward a stable, flat electricity demand profile among businesses. This mechanism reflects the structure of the power system, which is based primarily on conventional sources. Meanwhile, according to the National Energy and Climate Plan of June 2026, energy production from renewable sources will grow rapidly. In the accelerated transition scenario (with additional measures – so-called WAM scenario), electricity generation from solar and wind will amount to 91.5 TWh in 2030 and 170.2 TWh in 2040. This will account for 47% and 63% of total electricity generation, respectively. This necessitates making the system more flexible and linking balancing operations more closely to price signals for all users.

It should be noted, however, that the proposed change to the capacity fee mechanism may increase costs for some energy-intensive consumers. This applies in particular to entities with a flat consumption profile. Given their importance for maintaining production capacity in Poland and Europe, it is reasonable to introduce temporary support mechanisms to offset the increase in energy costs during the transition period. These solutions should be designed as part of a broader industrial policy.

1. Introduction

The European Union is gradually moving away from an economy based on fossil fuels and import dependence. Amid growing geopolitical uncertainty, limited domestic raw material resources increase our exposure to the risks of price fluctuations and supply disruptions. Disruptions in the oil and gas markets have immediate, serious consequences for the economy, particularly for the industry. Reducing dependence on fossil fuels is therefore becoming a strategic priority for strengthening economic stability.

The way to build the independence and competitiveness of the European economy is through electrification based on zero-emission sources, primarily renewable energy. Some of their components, such as photovoltaic panels or certain parts of wind turbines, are not manufactured in Europe. However, any restrictions on their import will not immediately disrupt the operation of existing installations. An energy system based on decentralized sources of electricity and heat generation will also be less vulnerable to military attacks than large-scale energy infrastructure.

Nonetheless, weather-dependent renewable energy sources pose challenges for the power system. To balance energy supply and demand, it is necessary to increase the flexibility of the demand side. For industry, the transition away from fossil fuels will require a direct electrification of processes, particularly for those based on low- and medium-temperature heat (up to 400o C). To this end, industry should make maximum use of available renewable energy, including by using electric boilers or hybrid systems during periods of excess generation.

A significant barrier to the flexible electrification of industrial processes in Poland is the method of calculating the capacity fee. The current mechanism rewards a stable energy consumption profile, while imposing higher costs for increased energy use during daytime hours. These hours largely coincide with the period of peak energy production from photovoltaic installations. As a result, industrial companies have limited incentives to invest in electrification and to switch process heat generation technologies. This creates the risk that some plants will continue to rely on gas or biomass sources even after they cease to be cost-competitive. We refer to this phenomenon as the "gas and biomass trap"[1] .

Another consequence of this approach is the inability of industry to absorb surplus energy from renewable sources. As the scale of redispatching increases, this generates additional costs for the Transmission System Operator (TSO). Ultimately, these costs are borne by all electricity consumers. Therefore, increasing flexibility on the consumer side is a key mechanism for reducing the costs associated with ensuring the secure operation of the power system.

1 We wrote more on this topic in our report: *Production Under Pressure #2. Financial Aspects of the Electrification of Industrial Processing in Poland*

2. The Current Structure and Impact of the Capacity Fee on Electricity Consumers

2.1. The Origins of the Capacity Fee and the Role of the Capacity Market

In 2021, a new component was introduced to electricity bills in Poland – the capacity fee. Its purpose is to have end-users cover the costs of operating the capacity market.

Why was the capacity market created?

The capacity market[2], unlike the traditional energy market, compensates generators for the availability of generation capacity rather than for actual energy production. Under EU law, this constitutes a form of state aid[3]. Contracts for the first units were initiated in 2018, while their fulfillment of capacity obligations began in 2021. The market is expected to operate until the 2040s—currently, the longest contracts signed extend through 2046.

The capacity market was created in response to the declining profitability of coal-fired power plants, due to their advanced age, insufficient replacement investments and the associated risk of power outages, that could lead to insufficient generation capacity in the system. In addition to coal, the capacity market also contracted investments in new gas-fired units, demand-side response (DSR) services, and energy storage facilities.

2 The capacity market was introduced by the Act of December 8, 2017, on the Capacity Market, available in Polish here.

3 The European Commission's decision approving the Polish capacity market as compliant with EU state aid rules is available here.

Units contracted under the capacity market are compensated for their readiness to supply capacity in response to a call-out period, announced by the TSO during periods of high energy demand and the risk of a capacity deficit. At the same time, the mere presence of these resources in the system increases the security of supply. As a result, situations requiring the declaration of call-out periods occur rarely[4]. In most cases, demand is met through the standard functioning of the energy market.

4 Since the market's launch in Poland, this has occurred only twice (September 23, 2023, and November 6, 2024)

In December 2025, the last main capacity market auction in its current form took place. It contracted units that will begin generating energy in 2030. At the moment, the Polish government is negotiating with the European Commission (EC) regarding a new capacity market model. According to the original plans, it was to take effect in 2026[5].

2.2. Mechanism for Calculating the Capacity Fee

Households

For households, the capacity fee takes form of a monthly flat rate[6]. It is determined based on four thresholds of annual electricity consumption. The current flat-rate model is set to remain in effect until the end of 2027[7], and starting in January 2028, it is set to transition to a model based on consumption patterns. This will be made possible by the wider installation of smart meters in Poland. By the end of 2027, they are to be installed in 65% of Polish households. In the consecutive year, , such devices are expected to be in use in 80% of households. A wider implementation of remote-reading meters will enable precise hourly billing of the capacity fee. However, ensuring a consistent billing model for households both covered and not covered by remote metering in 2028 may pose a challenge.

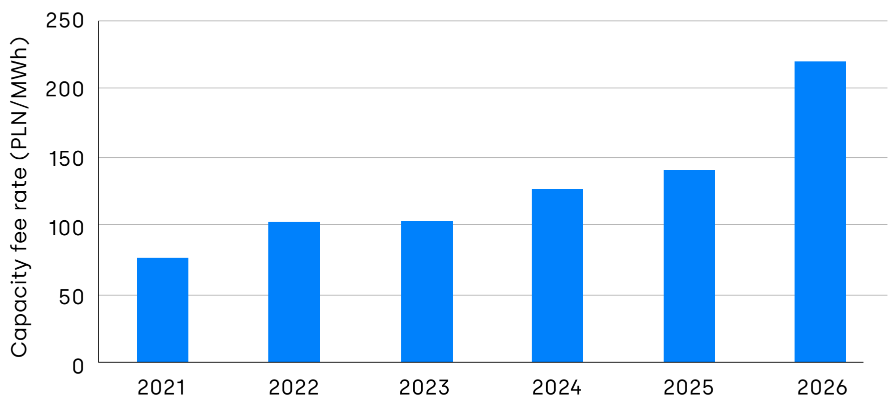
Industrial Customers

For other customers[8], including industrial customers, the capacity fee is calculated using the following formula:

$$\text{capacity fee amount} = \text{capacity fee rate} \left[\frac{\text{PLN}}{\text{WHh}}\right] * \text{amount of electricity drawn from the grid during peak power demand hours in the system [MWh]} * \text{coefficient [\%]}$$

The capacity fee rate is updated annually by the Energy Regulatory Office (URE) and may be set on a quarterly basis. To date, however, the URE has set a uniform rate for the entire supply year.

Figure 1. Capacity fee rates for industrial customers in Poland for 2021–2026 (PLN/MWh).[9]



Source: Author's own analysis based on announcements by the URE President

The URE also defines the hours of peak power demand in the system (hereinafter: hours for calculating the capacity fee). These may be set separately for each quarter and reviewed annually. However, they have not yet been changed by the regulator. Peak hours cover 15 hours during the business day, from 7:00 a.m. to 9:59

5 Summary of the implementation of the Government's priorities for the first quarter of 2026, report of the Committee for Oversight of Government Policy Implementation dated May 19, 2026 available in Polish.

6 The monthly flat rate is a form of settlement for the capacity fee also for other types of customers supplied from a grid with a rated voltage not exceeding 1 kV and a contractual power not exceeding 16 kW.

7 See the statement by the President of the Energy Regulatory Office on this subject available in Polish here.

8 Customers supplied from a grid with a rated voltage higher than 1 kV and a contracted power greater than 16 kW.

9 The significant increase in the capacity fee rate in 2026 resulted, among other things, from higher costs arising from capacity agreements.

p.m. The remaining seven hours (between 10:00 p.m. and 6:59 a.m.) are off-peak hours, during which the capacity fee is not applied. The capacity fee is also not applied on Saturdays, Sundays, and bank holidays.

Another key element in calculating the capacity fee for industrial customers is the coefficient, commonly referred to as a "discount." It rewards customers with a stable daily consumption profile and penalizes increased energy consumption during peak hours when the capacity fee is applied.

Depending on the difference in average electricity consumption during peak and off-peak hours, customers are classified into four groups. The difference used to calculate the capacity fee is determined according to the following formula:

Table 1. Classification of end users based on their electricity consumption profile under the current capacity fee mechanism.

Difference in average electricity consumption between peak and off-peak hours for the capacity fee (Δs)	End-user groups	Coefficient—basis for calculating the capacity fee
Δs < 5%	K1	17%
5% <= Δs < 10%	K2	50%
10% <= Δs < 15%	K3	83%
15% <= Δs	K4	100%

Source: Author's own calculations.

Starting in January 2025, the discount is calculated for each business day. Previously, data was averaged over the entire month (in 2021–2022) and over ten consecutive days of the month (in 2023–2024). The switch to a daily consumption measurement method has increased the system's sensitivity to short-term fluctuations in deviation. Customers must optimise their energy consumption on a day-by-day basis. They cannot offset high consumption on one day, with lower consumption at another time during the month.

For industry, the capacity fee currently accounts for several to over a dozen percent of the electricity bill[10].

2.3. Capacity Fee vs. Electricity Consumption Flexibility

The current capacity fee model penalises flexible consumers—that is, entities that adjust their energy consumption to prevailing system conditions. Yet, it is precisely this group of consumers that is particularly desirable for ensuring system stability and increasing system efficiency. Therefore, the importance of flexibility will grow, as the share of renewable energy sources increases.

To ensure that the capacity fee more effectively supports flexible energy consumption management, it is worth analysing two elements of its structure:

- the range of hours during which the capacity fee is calculated;
- the mechanism for calculating the discount.

10 Wójcik, J., Kwidziński, K., Pandera, J., & Trzeciak, D. (2026), *"Capacity at Any Cost? What Has Poland Achieved in 10 Years of Work on the Capacity Market?"*, Forum Energii.

2.3.1. The range of hours during which the capacity fee is calculated

According to the regulation of the Ministry of Climate and Environment, the capacity fee may be calculated only during hours when a call-out may occur on the capacity market[11]. However, the Energy Regulatory Office (URE) may limit this period to a minimum of eight hours, divided into two separate periods during the day. When determining these periods, the regulator should take into account historical or forecasted power demand in the system, considering the nature of the daily demand curve. Despite this option, since 2021 URE has consistently applied the full range of peak power demand hours in each quarter.

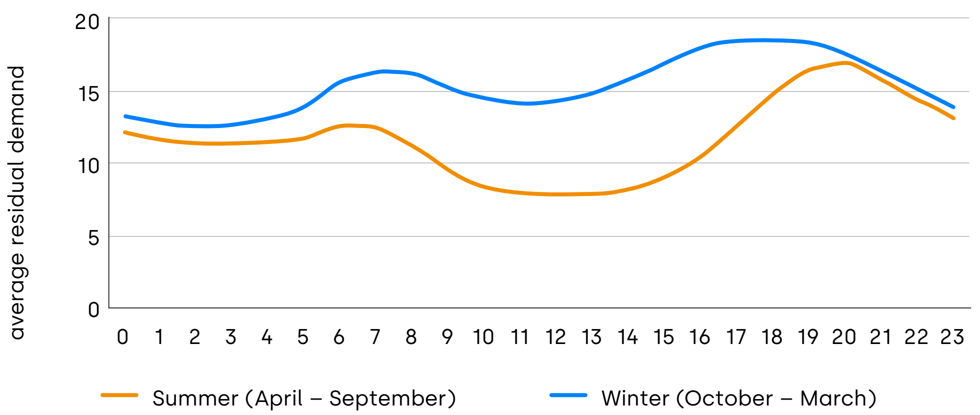
11 Regulation of the Minister of Climate and Environment of September 5, 2024, on the capacity fee, available in Polish here.

In 2025, demand during the capacity fee calculation hours (7:00 a.m.–9:59 p.m.) was on average about 25% higher than outside that period (10:00 p.m.–6:59 a.m.). This clearly shows that the time window set by the URE increasingly fails to reflect the actual challenges associated with meeting the system's capacity demand. Furthermore, both energy demand and renewable energy generation vary depending on the season. The current model does not account for this seasonality.

A much better measure of the scale of the challenges facing the system is residual demand—that is, total demand, minus the energy generation from renewable sources (solar and wind). It shows what portion of the demand must be met by other generation sources. Critical in the current structure of the power system are moments when residual demand changes rapidly over time. However, the design of the capacity market does not address this problem[12]. A significant short-term increase in demand for capacity from dispatchable sources occurs particularly during the evening hours. At that time, photovoltaic generation declines, while household energy demand rises.

12 Currently, the capacity market addresses only the issue of capacity demand, not the rate of change in that demand, both in terms of fees and the services ordered from energy producers. A generating unit's ability to rapidly increase generation is not taken into account in contracting or in the unit's remuneration on the capacity market.

Figure 2 . Average residual demand during the summer and winter of 2025 (GW)

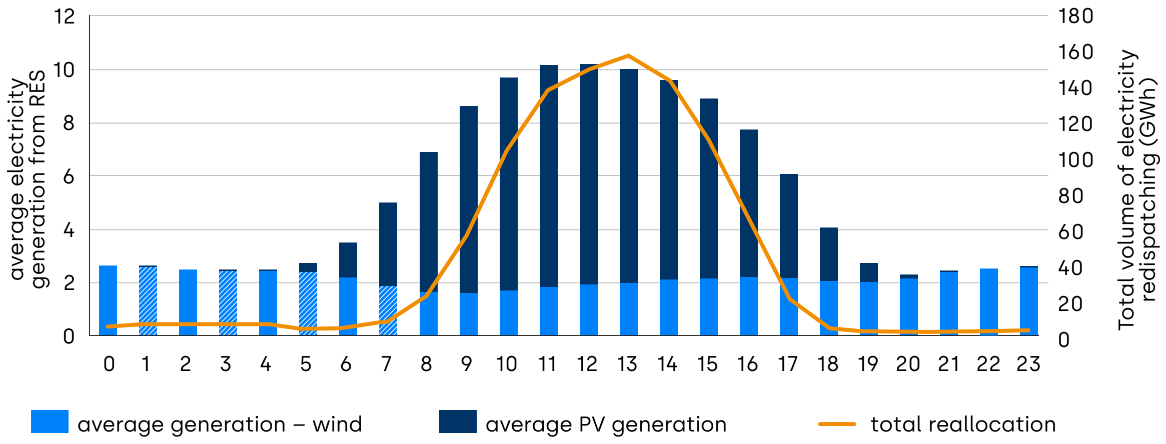


Source: Author's own analysis based on PSE data.

Seasonality is also playing an increasingly important role. In winter, residual demand is significantly higher during the hours when the capacity fee is applied. In contrast, in the summer, between 8:00 a.m. and 4:00 p.m., residual demand is lower than during the hours when the capacity fee is not applied.

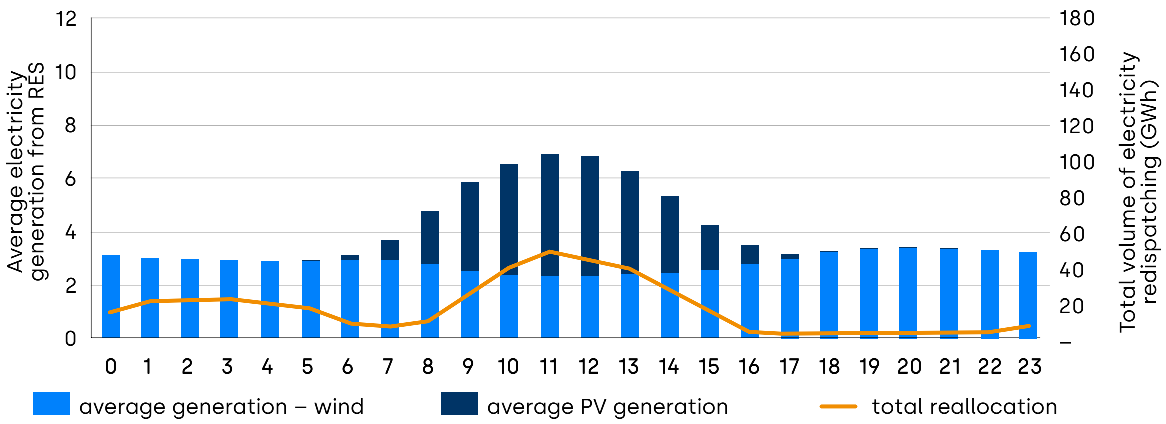
Under favourable weather conditions, when energy supply exceeds demand in the system, renewable energy production is curtailed. In practice, this means that some of the inexpensive, renewable energy is wasted. These periods partially overlap with the hours during which capacity fees are applied. It is precisely during these hours that photovoltaic energy generation is at its highest. The scale of this phenomenon can be partially assessed by analysing data on the non-market curtailment of generation units. The scale of curtailment differs significantly between summer and winter months.

Figure 3. Average hourly profile of electricity generation from weather-dependent renewables (GW) and total volume of electricity redispatching for each hour (GWh) during the summer of 2025 (April–September).



Source: Author's own analysis based on PSE data.

Figure 4. Average hourly profile of electricity generation from weather-dependent RES (GW) and total volume of electricity redispatching for each hour (GWh) during the winter of 2025 (October–March).



Source: Author's own analysis based on PSE data.

As a result, an industrial customer who would like to use some of the cheap energy (or energy with a negative price)—due to non-market production constraints – must expect to pay a higher capacity fee for drawing that energy. Thus, there is no way to optimise energy bills while simultaneously supporting the National Power System (KSE). Nor are there incentives to invest in solutions that increase flexibility and support decarbonisation, inter alia through electrification, hybrid process heat sources, or automation of energy consumption management.

At the same time, such a broad hourly window does not identify key moments of power deficit in the system. Thus, it does not encourage reducing consumption during the hours that are most challenging for the system. It treats all working hours between 7:00 a.m. and 9:59 p.m. equally.

2.3.2. Discount as the Basis for Calculating the Capacity Fee

Each customer is assigned daily to one of four end-user groups: K1 – K4. The assignment depends on the difference between average energy consumption during peak and off-peak hours. Based on this, a coefficient is determined to calculate the charge.

An increase in energy consumption during hours of high PV generation may result in a change in the end-user's rate class. This translates to a higher coefficient used to calculate the capacity fee. If consumption exceeds the average by 15% during the hours when the capacity fee is calculated compared to other hours, the customer moves from group K1 to group K4. **In practice, this means a capacity fee that is up to six times higher.**

For energy-intensive companies, the K1 group profile is the most advantageous. This is due to the high share of electricity costs in the company's balance sheet and the limited ability to change the consumption profile given the nature of production processes. Customers in this group benefit from a discount on the capacity fee, paying only 17% of the base rate.

The Energy Regulatory Office (URE) points to rising energy consumption among customers in the K1 group[13]. A 26% increase was one of the reasons for raising the capacity fee rates in 2026[14]. This means that despite rising energy consumption in this group, its share in covering the costs of the capacity market is not increasing proportionally.

In practice, the system must recover the shortfall in revenue from other consumers. Consequently, rising energy consumption in the privileged K1 group leads to an increase in the capacity fee burden on other consumer groups. This applies to both the K2 and K3 groups, which do not receive such a high discount, as well as the K4 group, which does not benefit from any discount at all. As a result, increased energy consumption during the hours when the capacity fee is calculated is further penalised.

Furthermore, this structure of the capacity fee does not encourage customers eligible for the discount to reduce their energy consumption during periods of peak system load and peak residual demand, such as on winter evenings (5:00–7:00 p.m.). This support mechanism therefore does not meet the needs of the power system and often runs counter to them.

13 URE (2025), Report on the Activities of the President of the Energy Regulatory Office [*available in Polish*].

14 The rising costs of the capacity market result from the increasing pool of capacity contracted in successive main auctions (as well as from the closing prices of those auctions) and from the indexation of long-term capacity contracts concluded in previous main auctions.

History of the Method for Calculating the Coefficient (Discount)

When the Capacity Market Act took effect, the discount for industrial customers was not linked to their electricity consumption profile. Under the model introduced by the Act in 2018, it depended on the electricity consumption intensity coefficient. This was defined as the share of electricity costs for own use in gross value added.

Table 1. Capacity fee coefficients depending on electricity consumption intensity in the original capacity fee mechanism.

Electricity consumption intensity coefficient (x)	Basis for calculating the capacity fee
x < 3%	100%
3% <= x <= 20%	80%
20% < x <= 40%	60%
x > 40%	15%

Source: Author's own analysis

This structure of the capacity fee protected energy-intensive consumers regardless of their consumption profile[15]. The role of companies in covering the costs of the capacity market was not proportional to consumption during the hours when the capacity fee was calculated, but was permanently linked to the intensity of electricity consumption. Through the discount mechanism, a greater share of the burden of financing the capacity market was shifted to less energy-intensive consumers.

As such , the discount would constitute a direct subsidy for energy-intensive consumers. Its implementation therefore required a notification decision by the European Commission, as it could distort competition in the internal market and constitute a selective economic advantage. The mechanism was subject to an in-depth review by the EC as part of the state aid procedure. Consequently, it was not retained, and its structure was revised to align with more systemic principles for allocating capacity market costs[16]. It was replaced by the currently used coefficient based on consumption profile characteristics. As intended, this coefficient is designed to differentiate capacity market costs based on electricity consumption profiles.

15 Patryk Matuszak, *"New Rules for Calculating the Capacity Fee for Energy Consumers in Tariff Group B Starting in 2022,"* Radar Prawny, 2021 [available in Polish].

16 Act of July 23, 2021, Amending the Act on the Capacity Market and Certain Other Acts [*available in Polish*].

3. Trends in Changes to the Capacity Fee for Industry

As the importance of energy demand flexibility grows, proposals to modify the structure of the capacity fee are appearing more frequently in public debate. Reform proposals focus on strengthening price signals and better aligning charges with the actual situation in the power system.

Selected approaches and recommendations in this regard are presented below.

3.1. ACER recommendations

The overarching EU recommendation[17] regarding capacity fees is based on the principle that the costs of operating the capacity market should be appropriately shared among market participants. These costs should be borne primarily by those entities that contribute to capacity adequacy issues and thus justify the need for the mechanism.

The key reference point are ACER's recommendations[18] regarding the design of network and capacity fees. ACER emphasizes the need to increase the economic efficiency and transparency of capacity market mechanisms.

Accordingly, it recommends that the capacity fee should be levied on the demand that causes periods of high load in the power system (stress periods). The mechanism for calculating this charge should cover the costs of the capacity market while also providing price signals to reduce consumption during peak periods. An appropriately structured capacity fee should reduce the amount of capacity contracted through the capacity market. The result should be a reduction in the cost of operating the capacity market.

ACER identifies several aspects of capacity fee design. The most important ones are presented below:

1. **Billing Period**

The billing period is the time during which electricity consumption is subject to the capacity fee. It may vary based on, among other factors:

- season;
- type of day (business day / non-business day);
- time of day.

17 European Commission, *Guidelines on State Aid for Climate, Environmental Protection, and Energy*.

18 ACER (2024), *Security of EU Electricity Supply 2024 Monitoring Report.*

The billing period should reflect periods of high system load as precisely as possible. This provides a clear price signal during peak times and encourages behavioral changes.

It is recommended to vary the rates throughout the day. Billing periods that are too broad (e.g., all-day) weaken consumers' motivation to adjust their energy consumption if they are unable to shift their usage to nighttime hours.

2. Communication

The capacity fee should be calculated in a transparent manner. At the same time, it should be listed as a separate item on the electricity bill. The bill should also include information on ways to reduce the amount of this charge. This approach increases cost awareness and enables decisions to be made that reduce energy consumption during peak periods. The expected result is therefore a reduction in both individual bills and the total operating costs of the capacity market.

3. Customer Segmentation

Customer segmentation involves assigning different groups to different rates or methods for calculating the capacity fee.

This differentiation may take into account, among other factors:
- customer type (household / industrial customer)—this approach is already in use in Poland;
- energy intensity (high / medium / low);
- demand profile (flat / peak) – this approach is already in use in Poland.

In justified cases, it is possible to further differentiate the capacity fee, for example, for vulnerable customers. However, this approach requires careful balancing. Excessive protection of certain consumers against high peak rates weakens incentives to reduce consumption during periods of system overload. If the group of protected consumers is too large, the risk of oversizing the capacity mechanism increases. As a result, this may lead to an increase in the capacity fee for all consumers. A similar effect occurs when the costs of the state aid mechanism are financed from the state budget. In such a case, the price signal is diluted, as consumers do not see a direct link between their behavior and the level of support costs.

As a general rule, a capacity fee exemption for industry is not prohibited under EU law, but it constitutes a form of potential state aid, that requires an individual assessment of compliance with Article 107 of the TFEU and the Climate, Energy, and Environmental Aid Guidelines (CEEAG)[19]. The European Commission does not view such exemptions as a systemically preferred solution, but rather as an exception permissible only in justified cases, such as the risk of loss of competitiveness or carbon leakage.

19 Guidelines on State Aid for Climate and Environmental Protection and Energy Objectives, see here.

3.2. Legislative Proposal by the IEO and PIME

An example of adapting the capacity fee mechanism to the growing share of renewables is the proposal presented in 2025 by the Institute for Renewable Energy (IEO) and the Polish Chamber of Energy Storage and Electromobility (Polska Izba

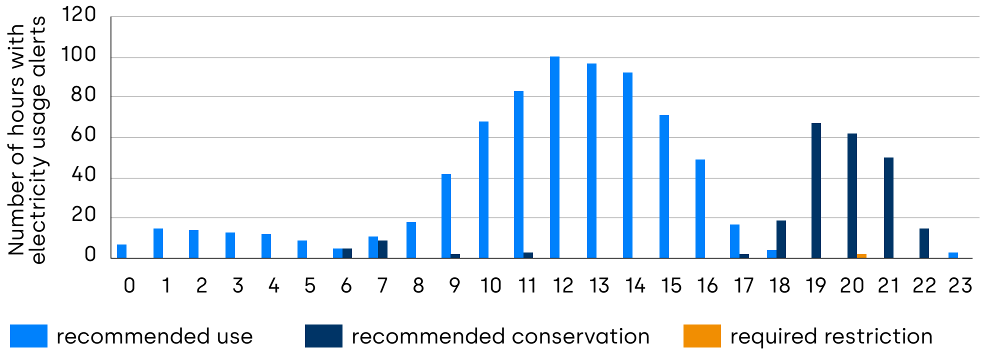
Magazynowania Energii - PIME) in their report "*Green Electrification of District Heating*"[20].

The solution involves introducing partial exemptions from distribution and network charges during periods of surplus renewable energy. Its goal would be to increase consumption during periods of energy oversupply and to reduce the scale of unused renewable energy, including non-market reallocation. Under this model, energy consumers could benefit from preferential tariff terms, including, among other things, exemptions from selected components of network charges, such as the capacity fee.

Although the proposal was designed with the heating sector in mind, it could also be considered for a broader group, including industrial customers.

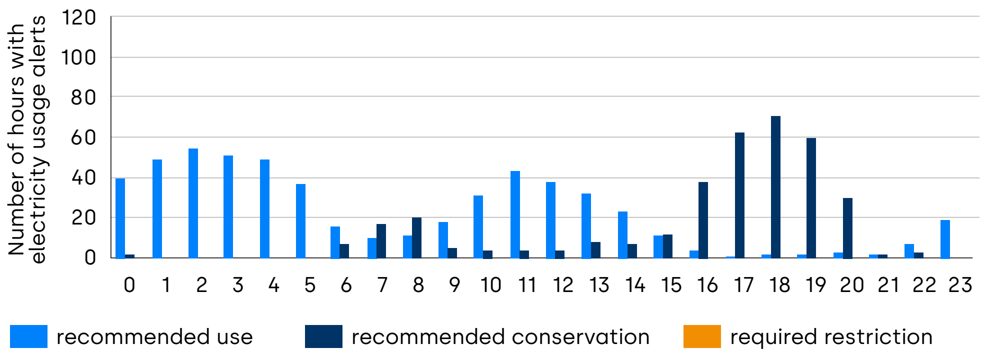
In the proposed model, the transmission system operator would be responsible for identifying times when energy surpluses occur and informing the market about opportunities to utilise them, e.g., through the Energetyczny Kompas (Energy Compass) app.

Figure 5. Number of electricity usage alerts in the Energetyczny Kompas (Energy Compass) on an hourly basis during the summer (April–September) of 2025 (number of hours).



Source: Author's own analysis based on PSE data.

Figure 6. Number of electricity usage alerts in the Kompas Energetyczny (Energy Compass) on an hourly basis during the 2025 winter season (number of hours).



Source: Author's own analysis based on PSE data.

20 IEO and PIME (2025), *Green Electrification of District Heating* [*available in Polish*].

Implementing the mechanism proposed by IEO and PIME in 2025 would reduce the number of hours subject to the capacity fee by 359 hours during the summer and 97 hours during the winter, respectively.

Under this proposal, the trading of surplus energy would take place through PPAs between renewable energy producers and consumers. Participation in this mechanism would entail an obligation to purchase the contracted energy, subject to penalties. Sanctions would apply to both parties to the agreement. The Settlement Administrator would maintain a registry of such agreements.

This solution would better fulfill the original purpose of the capacity fee, which is to ensure security of supply and mitigate the risk of capacity shortages in the National Power System.

However, this solution applies only to surplus energy. It also requires the conclusion of separate PPAs. This may pose a barrier for some industrial consumers, especially since it requires finding generators willing to enter into such contracts. This adds to the complexity of the already complex capacity fee structure. Furthermore, the solution does not address in any way the systemic challenges related to demand flexibility highlighted by ACER.

3.3. Case Study – Capacity Fee in Italy

An example of a model in which the capacity fee is based on strong price signals is the model used in Italy[21]. The European Commission approved the support mechanism for the Italian capacity market in 2018, and the first auctions took place in 2019.

21 Ricerca di Sistema Energetico (2023), *The Italian Capacity Market*.

The capacity market in Italy is based on auctions organised by the TSO. It is supplemented by a secondary market, which allows for the adjustment of previously concluded contracts monthly. New and existing generation units, as well as DSRs, participate in the auctions. Contracts for new units can last up to 15 years, and for existing units – 1 year.

Contracted capacity is compensated with a fixed annual premium. In return, generators must offer their contracted capacity on the energy market during every hour that the capacity market is in effect. If, during a given hour, prices on the energy market exceed the strike price, the generator returns the excess revenue to the system operator. This mechanism limits the possibility of earning above-average profits from the day-ahead market.

The costs of the Italian capacity market are financed by all electricity consumers. The capacity fee depends on electricity consumption. The system includes two rates:

- **A charge levied for electricity consumption during off-peak hours** – covers approximately 30% of the capacity market's costs. Its value may be updated monthly.
- **A charge for electricity consumption during peak hours** – covers approximately 70% of the capacity market's costs.

The rate charged during peak hours is higher than the rate during off-peak hours. In 2025, the peak-hour rate was 59.049 euros/MWh, and the off-peak rate was 3.631

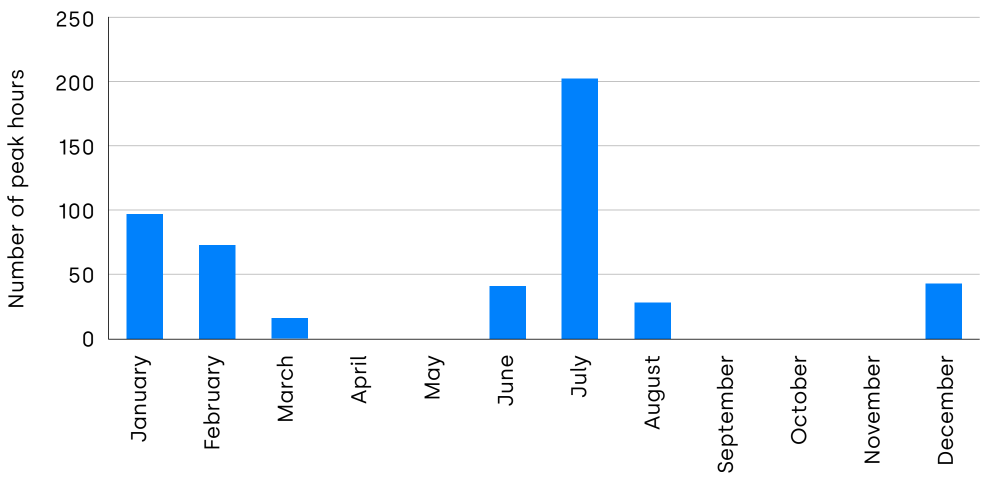
euros/MWh[22]. Peak hours cover 500 hours per year. These are periods when the forecast surplus of electricity supply over demand is at its lowest. They account for less than 6% of hours annually. By comparison, under the Polish capacity mechanism, this figure is approximately 43% of the hours. Information on peak hours is published in advance - by November 30 of the previous year. Consumers therefore know in advance the periods of potential capacity shortages and the associated high costs.

22 *Capacity Market: What It Is and How It Impacts Energy Costs,* Consorzio Esperienza Energia.

The limited number of peak hours under the Italian system gives consumers greater flexibility to shift their energy consumption to off-peak periods. At the same time, peak hours are concentrated during periods of the highest risk of system shortages. In 2025, these hours fell during the winter months of December through February and during the summer months of June through August, when energy demand in Italy rises due to the use of air conditioning.

Figure 7. Peak hours as defined for capacity fees in Italy, announced for 2025, monthly breakdown[23].

23 Terna, *Annual and Weekly Peak Hours 2025.*



Source: Author's own analysis based on data from Terna.

This approach is consistent with some of ACER's recommendations. Significant differentiation of price signals based on system load, precise definition of peak demand periods, and the absence of consumer segmentation provide a strong incentive for energy consumers to reduce their impact on the power system. This makes it possible to reduce the volume that must be contracted within the capacity market, which translates into lower operating costs.

4. The Analysis of the Impact of Changes to the Capacity Fee Mechanism on Elasticity

4.1. Assumptions for the Analysis

The analysis was conducted based on the previously described possible directions for changes to the capacity fee mechanism (see Chapter 3). Five variants of the capacity fee structure were considered:

Table 3. Analysed capacity fee variants.

V1 – "evening consumption"	**Variant description**	**Analysis results**
	Current structure of the capacity fee.	Table 5
V2 – "evening consumption, no reward for a flat consumption profile"	Current mechanism with a change in the hours during which the capacity fee is calculated.	Table 6
	Current mechanism with a change in the hours for calculating the capacity fee and the elimination of the discount.	Table 7
V3 – "management of surplus"	The current mechanism with the elimination of the capacity fee during hours of surplus renewable energy production and without taking those hours into account when determining the coefficient (proposal by IEO and PIME, adapted to the capacity market).	Table 8
V4 – "Italian option"	A two-tier capacity fee, involving a differentiation in the capacity fee rate between peak and off-peak hours, with the off-peak rate set at approximately 1/16th of the peak rate. Precisely identified a specific number of key peak hours with the greatest annual capacity deficit (e.g., 500–1,000). No discount.	Table 9

Source: Author's own work.

The analysis aims to demonstrate the impact of changes in consumer behavior on a company's capacity fee. The study examined whether specific capacity fee structures promote flexibility, as well as whether the measures taken lead to an increase or decrease in the capacity fee. The scope does not include a precise calculation of the costs incurred by companies; these are hypothetical models.

The analysis is based solely on data for the summer period. A comprehensive assessment of the new mechanism's impact on the capacity fee must also take winter conditions into account. During winter, the key challenge for the system is not managing energy surpluses, but mitigating capacity shortages during peak demand hours.

The hours for calculating the capacity fee in Scenarios 1–3 were limited to the hours during which capacity can be called upon on the capacity market, i.e., 7:00 a.m.–9:59 p.m. These hours were determined based on data from 2025. In Scenarios 1 and 2, it was assumed that these are hours with higher average residual demand than during the hours of 10:00 PM–6:59 AM. In Scenario 3, the surplus hours were determined based on more than 50 "recommended usage" indications in the Energy Compass. In Scenario 4, the three hours with the most frequent "recommended conservation" indication in the Energy Compass were selected.

Table 4. Peak and off-peak hours in the analyzed capacity fee scenarios.

Variant/Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
V0: Current mechanism																								
V1: Change in the range of hours for calculating the capacity fee																								
V2: Change in the range of hours for calculating the capacity fee and elimination of the discount																								
V3: Exclusion of hours with renewable energy surpluses from the capacity fee											X	X	X	X	X	X								
V4: Two-zone capacity fee																								

Source: Author's own work.

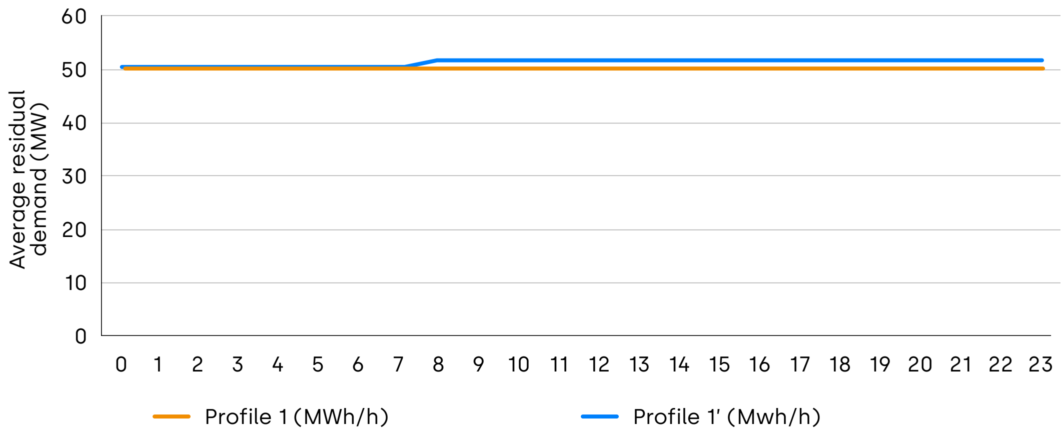
Legend: red – hours during which the capacity fee applies; green – hours without the capacity fee; yellow – hours of renewable energy surpluses.

Three electricity demand profiles were analysed. A baseline profile was developed for each of them (Profiles 1, 2, 3). Next, profiles modified relative to the baseline were prepared. These assume the possibility of increasing consumption during hours of high renewable energy production (Profiles 1', 2', 3'). Additionally, the possibility of reducing consumption during selected hours when capacity fees are applied and residual demand is high was taken into account (Profiles 2'', 3'').

Profile 1 in the baseline scenario is a flat 50 MW profile.

Profile 1' allows for a 3% increase in consumption. For industrial facilities, this corresponds to a change in the energy mix for a hybrid boiler, e.g., from natural gas to electricity. No reduction in consumption or return to baseline values is anticipated during the hours when the capacity fee is calculated. This is due to the requirement to maintain production quality parameters. Increased consumption therefore occurs between 8:00 a.m. and 11:00 p.m.

Figure 8. Hourly profile of Profile 1 and Profile 1' (MW).

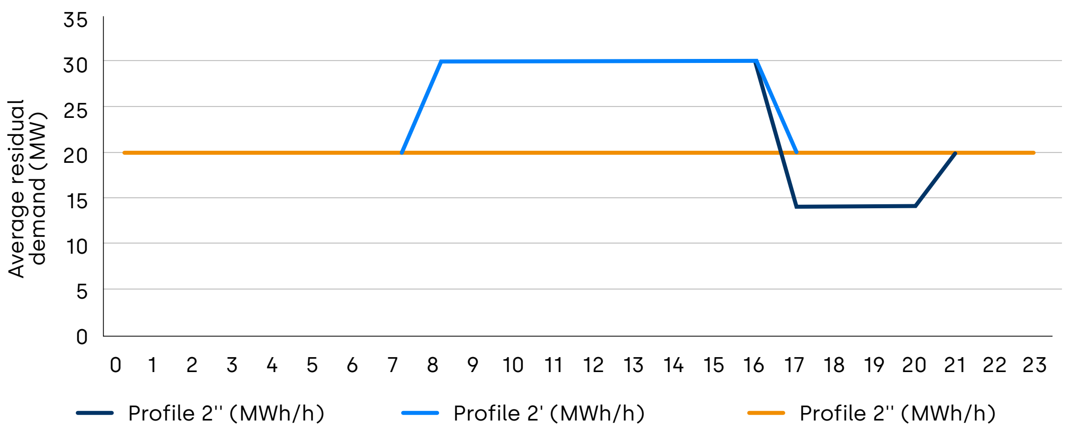


Source: Author's own analysis based on interviews with industry representatives and the ELMAS database[24].

Profile 2 in the base scenario is a flat 20 MW profile. Profile 2' allows for an increase in consumption of approximately 50% when using a hybrid boiler, followed by a rapid return to the base level. The increased consumption occurs between 8:00 a.m. and 4:00 p.m.

Profile 2'' also accounts for a 30% reduction in consumption thanks to the use of a 6 MW energy storage system with a 4-hour operating time. The storage system is charged during hours of high renewable energy production. The reduction occurs between 5:00 PM and 8:00 PM.

Figure 9. Hourly trends for Profile 2, Profile 2', and Profile 2'' (MW).



Source: Author's own analysis based on interviews with industry representatives and the ELMAS database.

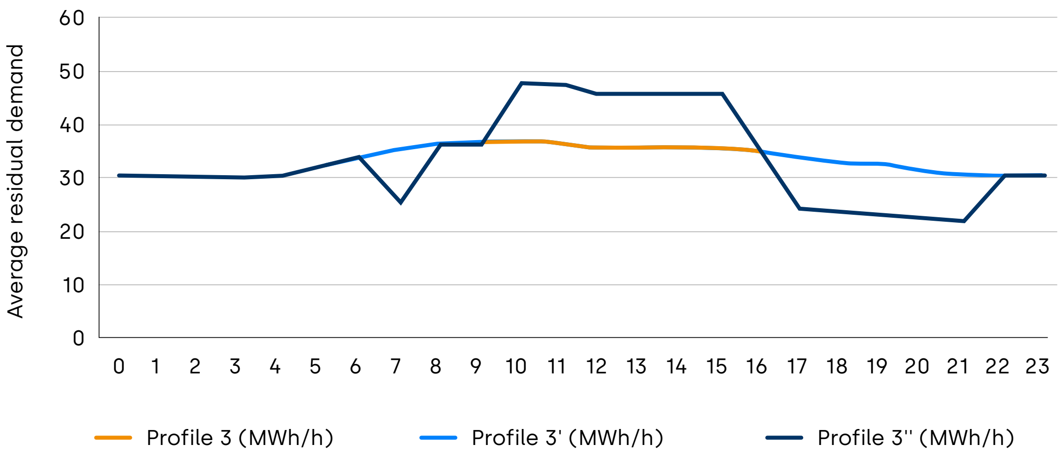
Profile 3 in the baseline scenario is characterised by increased demand during capacity fee hours, fluctuating around 32 MW.

Profile 3' assumes the possibility of increasing consumption by approximately 30% using an electrode boiler. The increased consumption occurs between 10:00 a.m. and 3:00 p.m.

24 Bellinguer, K., Girard, R., Bocquet, A., et al. ELMAS (*Electrical Load Measurements Aggregated by Business Sectors in France*): a one-year dataset of hourly electrical load profiles from 424 French industrial and tertiary sectors. Sci Data 10, 686 (2023).

Profile 3'' additionally accounts for the possibility of reducing consumption by 28.5% during peak-load billing hours through the use of a heat storage system with 95% efficiency, charged entirely from the demand generated by the electrode boiler. The reduction occurs between 5:00 PM and 9:00 PM and at 7:00 AM.

Figure 10. Hourly profiles for Profile 3, Profile 3', and Profile 3'' (MW).



Source: Author's own analysis based on interviews with industry representatives and the ELMAS database.

4.2. V0 – current mechanism

Table 5. Results of the analysis of variant 0 for changes in the capacity fee across different demand profiles.

	Profile 1	Profil e1'	Profile 2	Profil e2'	Profile 2''	Profile 3	Profile 3'	Profil e3''
Difference in average electricity consumption between peak and off-peak capacity fee periods (Δs)	0%	2%	0%	30%	22%	12%	26%	14%
Recipient group	K1	K1	K1	K4	K4	K3	K4	K3
Coefficient (basis for calculating the capacity fee)	17%	17%	17%	100%	100%	83%	100%	83%
Change in energy consumption compared to the baseline profile	0%	+2%	0%	+19%	+14%	0%	+8%	+1%
Change in capacity fee compared to the baseline profile	0%	+3%	0%	+665%	+618%	0%	+35%	+2%

Source: Author's own analysis.

The current capacity fee mechanism discourages deviations in electricity consumption of more than a few percent during capacity fee billing hours compared to off-peak hours.

The example of Profile 2' shows that, with a flat baseline profile, an increase in consumption during periods of high renewable energy generation can lead to a more than sixfold increase in the capacity fee. Even the use of a 4-hour energy storage system in Profile 2'—which limits consumption during the evening's peak hours—does not result in a significant reduction in the charge.

Smaller changes are observed in the case of Profile 3. In the baseline scenario, it qualifies for Group K3. An increase in energy consumption during periods of surplus results in a change to Group K4 and an increase in the capacity fee of approximately 35%. In contrast, the use of a thermal storage system, which draws surplus energy from the grid, allows a return to the K3 group. However, storage losses still cause a slight increase in the capacity fee.

4.3. V1 – "evening consumption"

When we combine the above profiles with the capacity fee modification scenario described above, we obtain the following result.

Table 6. Results of the analysis of Option 1 for changes to the capacity fee across various demand profiles.

	Profile 1	Profile 1'	Profile 2	Profile 2'	Profile 2''	Profile 3	Profile 3'	Profile 3''
Difference in average electricity consumption between peak and off-peak capacity fee hours (Δs)	0%	1%	0%	-20%	-36%	-2%	-11%	-37%
Recipient group	K1	K1	K1	K1	K1	K1	K1	K1
Coefficient (basis for calculating the capacity fee)	17%	17%	17%	17%	17%	17%	17%	17%
Change in energy consumption compared to the baseline profile	0%	+2%	0%	+19%	+14%	0%	+8%	+1%
Change in capacity fee compared to the baseline profile	0%	+2%	0%	+0%	-20%	0%	+0%	-29%

Source: Author's own analysis.

Limiting the hours during which the capacity fee is applied to the six hours of peak summer residual energy demand (7:00–7:59 and 17:00–21:59) results in **all businesses being classified into group K1.** This is due to the structure of the coefficient. It is based on the difference between average energy consumption during hours subject to the capacity fee and those not subject to it. High consumption between 8:00 a.m. and 4:59 p.m.—which are classified as hours during which no capacity fee is levied—results in a negative difference in this case. As a result, companies that adjust their consumption to match surpluses of renewable energy in the grid can benefit from a lower capacity fee rate. This variant of the capacity fee does not penalise energy consumption during periods of high renewable energy production.

The future introduction of solutions related to energy storage and limiting consumption from the grid during the hours when the capacity fee is calculated will further reduce its level. **As a result, this mechanism provides a clearer price signal, encouraging consumers to limit their energy consumption during the narrower time window when the capacity fee is calculated.**

4.4. V2 – "evening consumption, no reward for a flat profile"

Table 7. Results of the analysis of Option 2 for changing the capacity fee across various demand profiles.

	Profile 1	Profile 1'	Profile 2	Profile 2'	Profile 2''	Profile 3	Profile 3'	Profile 3''
Change in energy consumption compared to the baseline profile	0%	+2%	0%	+19%	+14%	0%	+8%	+1%
Change in capacity fee compared to the baseline profile	0%	+2%	0%	0%	-20%	0%	0%	-29%

Source: Author's own analysis.

In Option 1, the hours for calculating the capacity fee were changed, so all entities were classified into group K1. The complete elimination of the coefficient in Option 2 leads to the same results regarding the capacity fee for all profiles—all are classified as K1. We would likely achieve the same effect if the number of hours used to calculate the capacity fee were significantly lower than the current 15 hours.

This option is more predictable and less complicated for consumers. It does not require analysing the 24-hour consumption profile to determine the most favorable group. It is sufficient to monitor consumption during the limited number of hours for which the capacity fee is calculated. This option promotes flexibility while being less burdensome for businesses.

However, in order to fully cover the operating costs of the capacity market while reducing the number of hours subject to the capacity fee, the rate of the charge must be increased.

4.5. V3 – "management of surplus"

Option 3 was designed based on the legislative proposal by IEO and PIME described in Chapter 3.2. In this option, energy consumed during surplus hours is not included in the capacity fee or in the determination of the consumer group.

Table 8. Results of the analysis of Option 3 for changes to the capacity fee across various demand profiles.

	Profile 1	Profile 1'	Profile 2	Profile 2'	Profile 2''	Profile 3	Profile 3'	Profile 3''
Difference in average electricity consumption during peak and off-peak capacity fee hours (Δs)	0%	1%	0%	13%	5%	12%	12%	0%
Recipient group	K1	K1	K1	K3	K2	K3	K3	K1
Coefficient (basis for calculating the capacity fee)	17%	17%	17%	83%	50%	83%	83%	17%
Change in energy consumption compared to the baseline profile	0%	+2%	0%	+19%	+14%	0%	+8%	+1%
Change in capacity fee compared to the baseline profile	0%	+2%	0%	+453%	+210%	0%	+0%	-82%

Source: Author's own analysis.

The greatest benefits of this option are evident in Profile 3. It assumes increased energy consumption exclusively during hours of renewable energy surplus, followed by its use during nighttime hours thanks to thermal storage. In Profile 2, increased energy consumption does not fully align with periods of renewable energy surplus. This results in a more than fourfold increase in the capacity fee. Reducing this charge requires the use of a higher-capacity energy storage system or better alignment of consumption with periods of renewable energy surplus.

This variant supports only companies capable of continuously adjusting their consumption profile to actual signals from the system.

4.6. V4 – "Italian option"

Option 4 was developed based on the capacity fee model in Italy, described in the chapter 3.3 . As in the Italian model, 500–1,000 peak hours per year were assumed. In the analysis, these correspond to the hours 7:00 PM–9:59 PM, although they may vary from day to day. During off-peak hours, the rate is approximately 16 times lower than during peak hours.

Table 9 . Results of the analysis of Option 4 for changes in the capacity fee across different demand profiles.

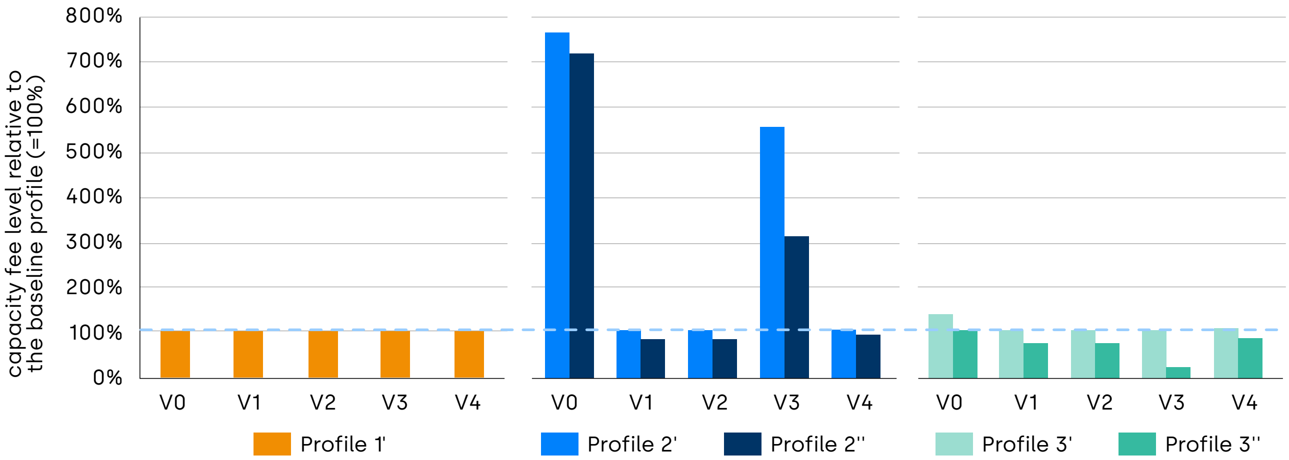
	Profile 1	Profile 1'	Profile 2	Profile 2'	Profile 2''	Profile 3	Profile 3'	Profile 3''
Change in energy consumption compared to the baseline profile	0%	2%	0%	19%	14%	0%	8%	1%
Change in capacity fee compared to the baseline profile	0%	+3%	0%	+7%	-8%	0%	+3%	-18%

Source: Author's own analysis.

The analysis indicates that an increase in energy consumption during periods of high renewable energy production or surpluses has little impact on the capacity fee. This is mainly due to an increase in total energy consumption, rather than higher rates during those hours. Conversely, reducing consumption during off-peak hours—for example, through the use of energy storage—allows for savings. This mechanism is simple and predictable for energy consumers. It therefore provides them with a clear price signal to change their behavior.

4.7. Summary – All Scenarios Better Support Flexibility

Figure 11. Level of capacity fee relative to the baseline profile (=100%) (%).



Source: Author's own analysis.

The current structure of the capacity fee clearly penalizes electricity consumption during hours of surplus renewable energy generation. It also provides only limited incentives for storing energy and then using it during periods of peak residual demand. The charge does not disappear entirely from the bill even when all the energy consumed during hours of high renewable energy generation is sent to storage. This is due to storage losses. Storage is therefore cost-effective mainly when using energy from one's own photovoltaic systems.

All of the analysed options for changing the method of calculating the capacity fee increase the possibilities for flexible energy consumption management. This applies both to increasing consumption during periods of high renewable energy production and to reducing it during peak power demand hours in the National Power System (KSE), among other things, through the use of energy storage facilities.

At the same time, the reduction in the number of hours for calculating the capacity fee proposed in Options 2 and 3 disrupts the functioning of the discount. This is because it leads to a "flattening" of the demand profile of consumers and an increase in the number of entities qualifying for the K1 group. This raises questions about the validity of such a solution. As the analysis shows, the elimination of the discount has a significant impact on the level of the capacity fee—costs increase for all industrial consumers, particularly in the event of modifications to the peak-hour schedule.

This study demonstrates, above all, that the current structure of the capacity fee does not promote flexibility on the part of industrial consumers. It should be emphasised, however, that the purpose of the capacity fee should be to support both "upward" flexibility (increasing energy consumption during periods of surplus, e.g., renewable energy generation) and "downward" flexibility (reducing consumption during hours of peak system load), which, under Polish conditions, occur particularly during the winter. Demonstrating this effect in detail would require a separate analysis.

5. Recommendations

The capacity fee was introduced to ensure security of supply and mitigate the risk of capacity shortages in the National Power System. Currently, however, it is also levied during periods of high energy supply and even surpluses. This contradicts its fundamental purpose.

As ACER points out, the capacity fee should not only finance the capacity market but also provide incentives to reduce consumption during periods of peak system load. This reduces the volume contracted on the capacity market and, consequently, lowers the operating costs of the entire system.

The mechanism should also support increased flexibility in electricity consumption by industrial customers, including through the use of hybrid systems (during the transition period prior to full electrification), electrode boilers with heat storage, and electricity storage systems. After 2028, the capacity fee for households should also provide greater incentives for flexible electricity use.

Achieving these goals requires changes to the structure of the capacity fee. In the Polish context, the reform should take four factors into account:

1. The hours during which the capacity fee is calculated should better reflect the risk of capacity shortages.

For the capacity fee to effectively incentivise consumer behavior in line with the needs of the National Power System, it should not cover a too broad range of hours. The broader the period over which the charge is calculated, the weaker the price signal sent to consumers becomes.

It is worth considering differentiating the hours during which the capacity fee is calculated depending on the season or determining them based on an algorithm analogous to the Energy Compass. Alternatively, a pool of peak hours could be defined on an annual basis, during which a significantly higher capacity fee would apply than during other hours. Such hours should be announced to market participants in advance. This would increase predictability and facilitate energy consumption planning. However, it would require determining the number of hours with the greatest potential capacity deficit on an annual basis, as well as very accurate forecasts from the operator.

Limiting the period for calculating the capacity fee to eight hours per day, with variations by quarter, could be implemented by a decision of the Energy Regulatory Office (URE). Only a further narrowing of the scope would require legislative changes.

2. The discount for customers with a flat consumption profile should be eliminated.

We recommend moving away from the current classification of end-users into groups and the associated coefficient (discount).

The method of assigning industrial consumers to specific consumer groups is outdated and does not reflect the current needs of the power system's structure. The current mechanism penalises energy consumption during periods of surplus renewable energy production and does not sufficiently encourage reducing energy consumption during hours of peak residual demand in the system.

The growing share of the K1 group means that the distinction between groups is becoming less and less effective, while costs are rising for businesses in groups K2, K3, and K4.

Implementing Recommendation 1 (narrowing the hours during which the capacity fee is calculated) would also reduce the differences between consumption during capacity fee hours and consumption during other periods. This calls into question the justification for continuing to use the coefficient. Additionally, a reform of the capacity fee for households—planned for 2028—while maintaining the discount, could increase the risk of passing on capacity market costs to individual consumers.

3. A protective mechanism is needed for energy-intensive companies following the elimination of the discount.

The elimination of current preferential treatment would mean higher costs for energy-intensive consumers with a flat consumption profile. These entities are crucial for maintaining production capacity in Poland and Europe. Some of them have limited ability to adjust their consumption profiles, in part due to production quality requirements. Therefore, support mechanisms should be proposed to compensate these companies for the increase in energy costs during the transition period.

Compensation measures should be part of a broader industrial policy. They may draw on capacity market mechanisms, but should remain an initiative independent of the fees paid by a specific company as part of the capacity fee. Compensation could be based, for example, on average values for a given sector. This approach would maintain incentives to improve energy efficiency and increase consumption flexibility. Implementing such a solution would likely require separate notification as state aid.

4. Reforming the calculation of the capacity fee requires a transparent process.

Efforts to change the method of calculating the capacity fee should be conducted in the spirit of a social dialogue and be subject to public consultations involving expert communities. This process should be coordinated with potential amendments to the Capacity Market Act. This applies in particular to any proposals for a fundamental change in how this mechanism is financed, e.g., from the state budget rather than from end-users' bills[25]. ■

25 Referring to the proposal by the President of the Republic of Poland presented in the *"Cheap Electricity – 33%"* program [*available in Polish*].