

Capacity at any cost?

What has Poland achieved through 10 years of work on the capacity market?

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ANALISYS

Nearly a decade ago, the first work began on the concept of a capacity market in Poland. For the European Commission, it was a support mechanism for electricity producers. For the transmission system operator, it is a vital part of the energy market, providing tools to maintain required reserves and mitigate the risk of capacity shortages. Today, we can summarise the effects and the scale of the costs of the capacity market's operation in Poland for the years 2021 to 2046—approximately PLN 200 billion. This means that the discussion on energy security cannot be limited solely to capacity itself. Security should also be understood as the ability to deliver electricity to consumers at all times and the certainty that this energy will be affordable. In view of the announcements regarding the continuation of support through the capacity market, a key question arises: is Poland achieving its goal of capacity adequacy and security of supply effectively, or rather is it entrenching a “capacity at any cost” approach?

Key findings:

- **The strategic goal of the Polish capacity market is unclear.** The mechanism is an important tool for the transmission system operator (TSO) to ensure capacity adequacy. After almost a decade of the market in operation, however, the long-term strategy remains unclear. Although the mechanism is declared to support the energy transformation, in practice it has largely cemented the status quo of the Polish power sector by maintaining the operation of old and inflexible conventional units. Simultaneously, it encourages the construction of new gas capacity, while energy storage remains of limited importance. The design of the capacity market requires streamlining and a clearly defined objective to ensure the secure operation of the National Power System (NPS) within a zero-emission mix over the next decade.
- **The mechanism generates high costs.** The capacity market has supplemented the declining revenues of conventional generation units and provided an impetus for the construction of new capacity. However, it is a very costly solution and a multi-year commitment. We estimate that between 2021 and 2046, this mechanism will consume a total of approximately PLN 200 billion (at current prices) and will represent a significant item on the electricity bills of all consumers. The system operator and the Ministry of Energy announced the continuation of the capacity market, so it can be assumed that costs will increase in the coming years.
- **The capacity market insufficiently supports flexibility.** Improving the flexibility of the power system is an essential element of the energy transition. To date, the design of capacity market auctions has favoured existing coal units and large combined cycle gas turbine (CCGT) power plants, which have limited responsiveness to variable electricity supply. Relatively few of the more responsive open cycle gas turbine (OCGT) units or gas engines have emerged. Meanwhile, the strategy towards energy storage has been inconsistent. While this component is highly necessary, it is not for generation. Storage performs a different function in the system, which was not recognised in the current capacity market model. Also on the consumer side, the design of the capacity fee is incompatible with the need for flexibility. The charging method still rewards consumers with constant daily electricity consumption. Rewarding a flat consumption profile contradicts the necessity to make demand more flexible and shift energy consumption to hours of peak renewable energy source (RES) generation, often at the peak of the day.

- **Risk of capacity oversizing.** The system operator prefers access to dispatchable domestic conventional power plants. These are needed in the energy system, but there are also other ways of ensuring adequate capacity levels. The operator's approach, based on conservative assumptions (which was also challenged by ACER)¹ and a priority for dispatchable capacity, leads to system oversizing and the generation of excess costs, instead of seeking optimisation, for example, through better use of cross-border connections, RES, or other sectors such as industry and district heating.
- **The capacity market is not transparent.** Although it constitutes a form of public support, the way the auction results are published makes it impossible to identify the beneficiaries of the contracts.

What is the capacity market in Poland and how does it work?

For years, the logic of how the electricity market operated was simple: system generators' revenues came mainly from selling electricity. This was an effect of the liberalisation of the energy market, which aimed to introduce market-based principles for remunerating generators, break up monopolies, and move away from centrally controlled cost-setting in the power sector.

It was assumed that new investments would be financed solely from revenues from electricity sales in an energy-only market model, in which prices reflect the relationship between supply and demand. However, the rapid expansion of renewable sources with zero variable costs has reduced wholesale electricity prices, making large, dispatchable conventional units lose profitability, even though they remain essential for system security.

Although RES generation can be forecast well, it is more difficult to control. When the wind blows and the sun shines, there is no cheaper energy than that. But solar and wind generation do not occur on a windless night. Conventional units are therefore still necessary, albeit in a different way than in the past. If operators do not adapt to the change in generation model, they will lose market share and revenues.

In the absence of a coherent political concept for modernising the Polish power sector, the transmission system operator (PSE) took the initiative, promoting the capacity market as a guarantor of the availability of dispatchable sources. The operator played a key role in designing and implementing the regulations governing the capacity market. It now fully controls this instrument, treating it as a priority tool for maintaining security of supply. In this approach, the broader economic context of the transition remains secondary.

The implementation of the capacity market began with the 2017 Act², intended as a response to the deteriorating prospects for balancing the national power system. Conventional units that had operated for years without a coherent modernisation concept began to generate losses resulting from:

- advanced age,
- lack of replacement investments,
- inefficient asset management.

This was the result of prolonged revisions of strategic documents and the adoption of unrealistic targets, justified mainly on political grounds. A striking example was the persistent underestimation of the pace of RES deployment, alongside an overestimation of the need to maintain coal-fired units. Poor planning of the energy transition increases its costs and raises the burden on consumers.

At the same time, in the face of the EU's accelerating decarbonisation policy, the capacity market mechanism became subject to restrictions, particularly with regard to coal, and ultimately also gas. EU state aid rules became key, including the Do No Significant Harm (DNSH) principle, which excludes the financing of projects that undermine the EU's environmental objectives.

Over subsequent years, restrictions on support for coal capacity were introduced at the EU level (from 2019, the so-called 550 g CO₂/kWh limit³), and later also for gas capacity (a tightening of the rules after 2021 together with the "Fit for 55" package⁴).

1 ACER, *ACER suggests better reflecting the benefits of Europe's internal electricity market in Poland's National Resource Adequacy Assessment*, 2025, <https://www.acer.europa.eu/news/acer-suggests-better-reflecting-benefits-europes-internal-electricity-market-polands-national-resource-adequacy-assessment>

2 *Act of 8 December 2017 on the capacity market* (consolidated text: Journal of Laws 2025, item 610, as amended).

3 *Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity* (OJ EU L 158/54 of 14.06.2019).

4 European Commission, *Commission Communication – Guidelines on State aid for climate, environmental protection and energy 2022* (OJ EU C 80/1 of 18.02.2022).

Poland is at a turning point: the capacity market mechanism, which is to operate after 2030, requires redefinition. The Ministry of Energy, in cooperation with PSE, is working on a new regulation on capacity support, which makes the present moment an appropriate time to summarise the experience to date.

What is the capacity market?

The capacity market is a support mechanism in line with state aid rules, under which remuneration is granted for the availability to deliver capacity rather than for the electricity actually produced. Its overarching objective is to ensure the ability to meet peak demand and maintain the necessary reserves by supporting conventional units, energy storage, and demand side response (DSR).

The mechanism is subject to restrictions typical of state aid, which are intended to protect consumers from excessive costs and to enhance the integration of the EU internal energy market. At the same time, a debate is ongoing within the European Union as to whether capacity remuneration (that is, payment for availability) should take place alongside remuneration for electricity generation.

However, the greatest weakness of such a solution is the lack of a system-wide perspective and the lack of coordination between key stakeholders: ministries, the regulator, network operators, energy companies, and the mining sector.

In the case of RES, the pace of growth is uneven: PV capacity is expanding very rapidly, around 10 GW of offshore wind capacity has already been contracted, while the development of onshore wind—a cheaper source and crucial from a system perspective—remains clearly slowed by administrative and procedural barriers as well as by aggravated social tensions linked to the politicisation of this topic.

In the case of conventional power generation, as new dispatchable capacity is added, especially gas-fired, it is necessary to make the pathway for phasing out the most costly coal-fired units more realistic. Overly conservative scenarios in strategic documents are then quickly verified by market reality.

At the same time, maintaining domestic coal production increasingly results from non-market mechanisms: in practice, the gap between rising mining costs and the price acceptable to the power sector is compensated with public funds, which entrenches the sector's inefficient cost structure. In the background, new gas capacity is being developed and the nuclear power programme is being continued as part of the long-term restructuring of the generation mix. In such an approach, the overall calculation is lost, comprising system costs, the impact on competitiveness, and the real needs of consumers.

How do capacity auctions work?

The level of support is determined through a centralised, descending clock auction organised by the system operator, PSE. In successive auction rounds, the price is gradually reduced until the offered capacity supply covers the demand defined by the operator at the lowest possible system cost. Greater competition during the auction translates into a lower clearing price for capacity contracts. The contracted volume of capacity and the resulting revenues of units are adjusted by an availability factor, reflecting the actual ability of individual technologies to deliver capacity during periods of system stress.

The capacity market allows units that might otherwise become unprofitable to continue operating. It also provides a financial boost to potential new investments, becoming a decisive factor in whether and when a given unit is built.

The mechanism is financed through the capacity fee included in electricity bills for final consumers, who are charged to varying degrees. For households, the capacity fee is currently charged as a fixed monthly amount, while other consumers (for example industrial companies, commercial and service enterprises, public institutions, and agriculture) pay for each kilowatt-hour consumed during designated hours.

The capacity market consists of main, supplementary, additional, and top-up auctions, which differ in their time horizon and in the level of contracted capacity.

1. **Main actions** are the core auctions in the capacity market. They contract the largest volume of capacity obligations, and their results form the basis for demand in the remaining auctions. They take place five years before the delivery year, and the contracts awarded in this way differ depending on the units offered. Contracts are divided into:
 - 15-year (or 17-year if the unit does not exceed the emissions limit of 450 kg CO₂/MWh) for new generating units⁵,
 - 5-year (or 7-year if the unit does not exceed the emissions limit of 450 kg CO₂/MWh) for refurbished generating units,
 - 1-year for the remaining units, i.e., existing generating units, DSR, or foreign units.

The last main auction took place on 11 December 2025.

2. **Additional auctions** are a mechanism in place since the beginning of the capacity market. They take place in the year preceding the delivery year, and the quarterly contracts awarded in them correct the difference between the secured capacity and the forecast seasonal demand. Existing generating units, DSR and foreign units participate in them. Further auctions for individual quarters in 2027–2030 are planned.
3. **Top-up auctions** are a result of Poland being granted a derogation⁶ allowing old coal-fired units to participate in the capacity market until the end of 2028. So far, two top-up auctions have been held: for the second half of 2025 and for the whole of 2026. Further auctions for 2027 and 2028 are planned. Existing generating units, DSR, and foreign units can participate. The main beneficiaries, however, are old, high-emission coal-fired units. According to the transmission system operator, without financing from the capacity market they would become unprofitable, yet they will be necessary for the next few years to ensure a secure level of dispatchable capacity.

The volume of capacity contracted under top-up auctions is comparable to the capacity contracted during main auctions. As a result, it turns out that for some years, two to three times more capacity has been contracted than the demand initially indicated under the main auction.
4. **A supplementary auction** was conducted only once, in July 2025 (with delivery planned for 2029), carried out under the same rules as the main auction and with the same type of contracts. It was launched due to concerns about a potential capacity gap. Unlike top-up auctions, the supplementary auction was intended to support new gas projects that will remain in the system for many years.

So far, in Poland there have been 10 main auctions, 24 additional auctions, 2 originally unplanned top-up auctions, and 1 originally unplanned supplementary auction.

Under the current framework, a further 16 additional auctions are scheduled for individual quarters in 2027–2030, as well as two top-up auctions for 2027 and 2028. The operator may also apply to launch a supplementary auction for 2030 if it considers that the results of the main auction do not provide sufficient coverage of demand.

⁵ In the capacity market, the category of generating units includes electricity producers, combined heat and power producers, and electricity storage.

⁶ On 11 August 2025, the European Commission adopted Decision No. C(2025) 5575 granting Poland a derogation from *Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity*. As a result of this derogation, the obligation to comply with the 550 g CO₂/kWh emissions limit was shifted from mid-2025 to the end of 2028.

In the following part of the analysis, we will present charts showing achievable capacity, declared capacity, or a capacity obligation. Explanations of these terms and the differences between them are provided below.

- **Achievable capacity (net)** – the active power at which a generating unit can operate at nominal parameters for a period of no less than four consecutive hours, without detriment to the durability of the unit, reduced by the unit's own consumption.
- **Declared capacity** – the capacity that the provider declares during certification for the capacity market auction. It is no greater than the net achievable capacity. This value is multiplied by the KWD (availability correction factor) to obtain the capacity obligation for a CMU (capacity market unit) in a given auction.
- **Capacity obligation / contracted capacity** – the value reported in announcements of capacity auction results. This is the capacity that the CMU is obliged to deliver during a stress event (or to reduce, in the case of demand reduction units). It includes the availability correction factor, and the provider receives remuneration for this capacity under the capacity contract.

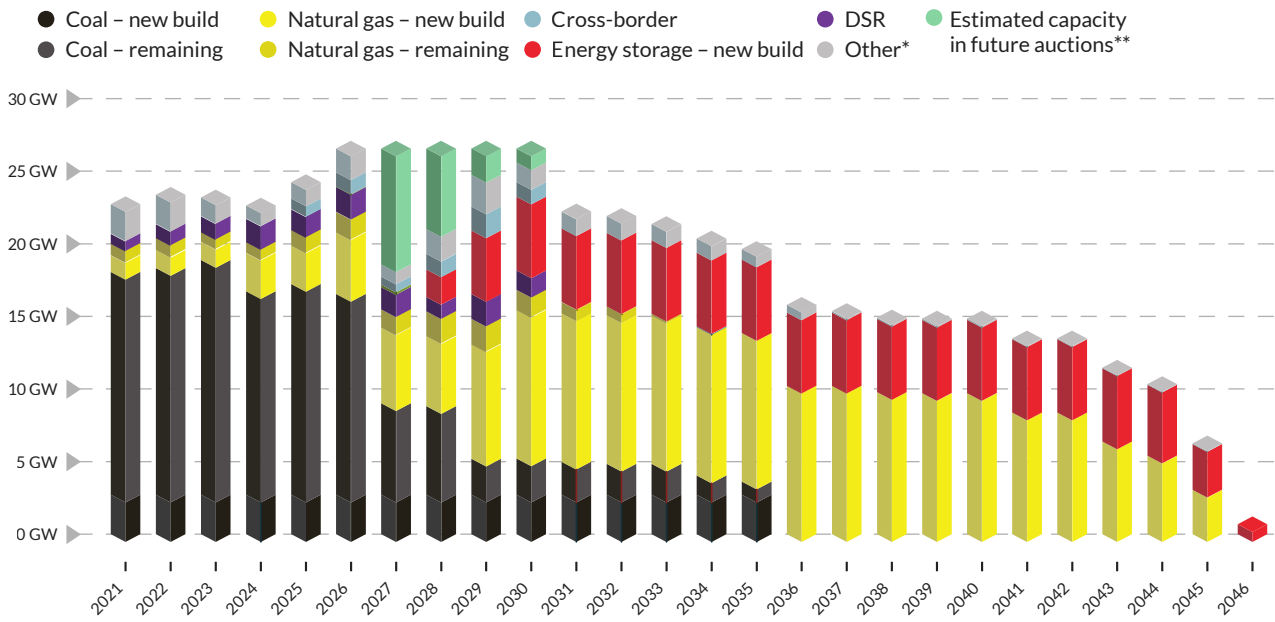
What has the capacity market delivered?

The capacity market has helped balance electricity supply in Poland. It has enabled some coal-fired power plants to continue operating and has created an investment impetus for new gas capacity, electricity storage, and demand reduction mechanisms (DSR, demand side response). In addition, in line with the EU internal energy market rules, the mechanism has been opened to the participation of cross-border capacity, with the aim of increasing auction competitiveness and optimising the costs of energy security. At the same time, the national power system is entering a period of gradual coal capacity retirements—the oldest, least efficient and most emission-intensive units are being withdrawn from operation, raising questions about system balance.

In recent auctions, however, a significant amount of gas capacity has appeared among the winning bids. The first gas units contracted under the capacity market are already operating in the National Power System, and further investments are being implemented and, despite delays, should progressively start operating over the coming years. In parallel, the energy storage segment is developing dynamically, increasing system flexibility and enabling more efficient use of the growing output from RES. These resources are complemented by DSR and contracted foreign capacity, which strengthen security of supply during periods of peak demand.

The structure of capacity obligations by technology and by individual capacity market auctions is presented in the following charts. Due to the lack of transparency of capacity auction results, it is not possible to determine unambiguously which unit will receive support and what its achievable capacity is. Where, due to a lack of available information, it was not possible to assign a capacity market unit to a physical generating unit, an estimated declared capacity was used.

Chart 1. Capacity obligations by type and technology

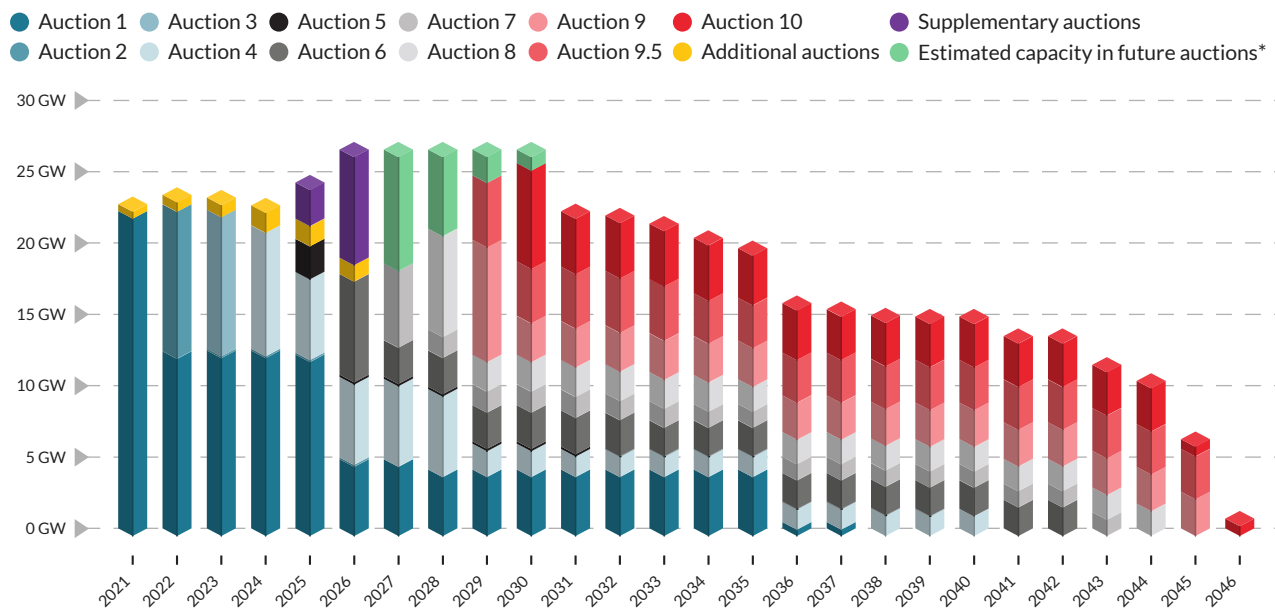
[Go to the interactive chart](#)


Source: own elaborations by Forum Energii based on capacity market auction results, media announcements, enquiries to companies, and internal assumptions. Values in the years 2021–2026 correspond to annual for the year 2030.

* Other, most of which are existing or refurbished hydro or biomass units.

** Estimates refer to supplementary auctions for 2027–2028 and additional auctions for 2027–2030. Capacity demand is assumed to be equal to the level of the last fully contracted year, i.e. 2026.

Chart 2. Capacity obligations by auction

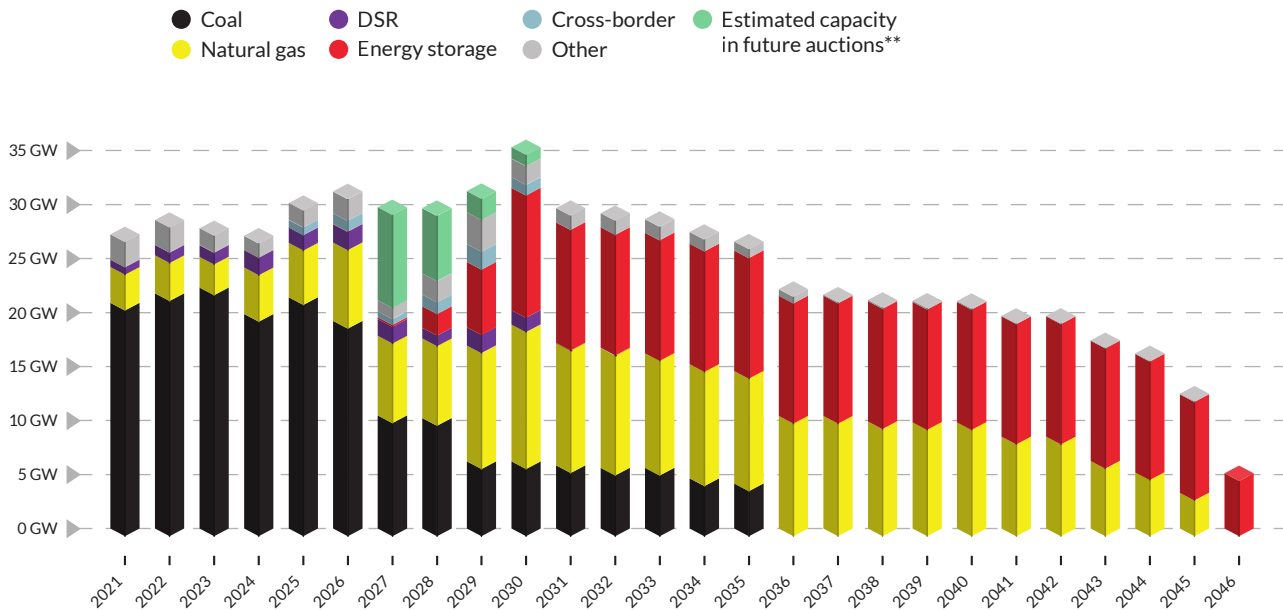
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Source: own elaboration by Forum Energii based on capacity market auction results, media announcements, enquiries to companies, and internal assumptions. Contracting status after the main auction for the year 2030.

* Estimates refer to supplementary auctions for 2027–2028 and additional auctions for 2027–2030. Capacity demand is assumed to be equal to the level of the last fully contracted year, i.e. 2026.

Chart 3. Estimated achievable capacity* by technology

[Go to the interactive chart](#)



Source: own elaboration by Forum Energii based on capacity market auction results, media announcements, enquiries to companies, and internal assumptions. Contracting status after the main auction for the year 2030. Values in the years 2021-2026 correspond to annual averages and may vary for individual quarters. * Where, due to a lack of available information, it was not possible to assign a Capacity Market Unit to a physical generation unit, the declared capacity was used. ** Estimates refer to supplementary auctions for 2027-2028 and additional auctions for 2027-2030. Capacity demand is assumed to be equal to the level of the last fully contracted year, i.e. 2026.

As the charts show, in successive auctions the capacity market attracted different technologies to varying degrees, generation, storage, and demand-side solutions. The scale of their participation depended on current economic conditions, the maturity of the technologies, and the readiness of market participants to submit bids. Correction factors also played an important role, as they modified the valuation of available capacity and, as a result, differentiated the competitiveness of individual technologies. The following section discusses the individual technologies.

Coal-fired units

In the first five years of the capacity market's operation, support went mainly to existing and refurbished units. Among the contracted generation capacity, around 80% consisted of coal-fired units. Old, high-emission coal-fired units were to receive support until mid-2025; however, as a result of a derogation, top-up auctions were announced, allowing these units to participate in the capacity market until the end of 2028.

Contracts awarded over many years and in large volumes to old coal-fired power plants have maintained the status quo. In this way, the operation of many existing power plants was extended – in most cases, these were coal-fired units that were several decades old. However, the operating costs of these units are high, which is now reflected in consumers' electricity bills.

In 2029, coal's dominance in the capacity market will end. Only 5.2 GW of capacity contracts for coal-fired units will remain within the support scheme, awarded under multi-year contracts⁷. This means a decline of more than two-thirds compared to 2026 (16.5 GW). Support for coal capacity will cease entirely at the end of 2035, which will not allow these units to cover their operating costs solely from revenues in the electricity market.

Gas-fired units

Beyond supporting existing units, the capacity market was also intended to provide an investment impetus for new generation capacity. At the outset, however, few new units were contracted, and a significant increase has become visible only in the most recent years of the mechanism. From 2029, gas-fired units will be the largest beneficiaries of the capacity market. In 2025–2030, their contracted capacity will more than triple from 3.8 GW to 11.6 GW.

⁷ This refers to relatively new units that received capacity contracts as a result of the first main auction: Unit 11 in Koźienice, Units 5 and 6 in Opole, Unit 7 in Jaworzno, and Unit 7 (lignite-fired) in Turów. This also includes refurbished units whose support will end before 2035.

New gas-fired units will operate in the system at least until the end of 2045. Most of them are CCGT units, which are not sufficiently adapted to operation in a system with a dominant share of RES. In this respect, the more flexible OCGT technology would be a better choice.

The following charts present a comparison of the basic technical parameters of selected generating units, which clearly illustrates differences in their level of flexibility. The table, in turn, provides a comparison of the basic specifications of generating units in gas technologies and a hard coal-fired unit.

Parameter	Coal unit	CCGT unit	OCGT unit	Gas engines
Ramp rate	4%/min	15%/min	20–30%/min	30–40%/min
Technical minimum	~40–60%	~40%	~40%	~50%
Electrical efficiency	~45%	~60%	~40%	~45%
CO ₂ emissions	~750 kg CO ₂ /MWh	~330 kg CO ₂ /MWh	~500 kg CO ₂ /MWh	~445 kg CO ₂ /MWh
Cold start	6–10 h	2–2,5 h	10–30 min	20 min
Hot start	2,5–3 h	60–90 min	5–15 min	5 min

Source: own elaboration based on data from DEA, NREL, Agora Energiewende, KOBIZE.

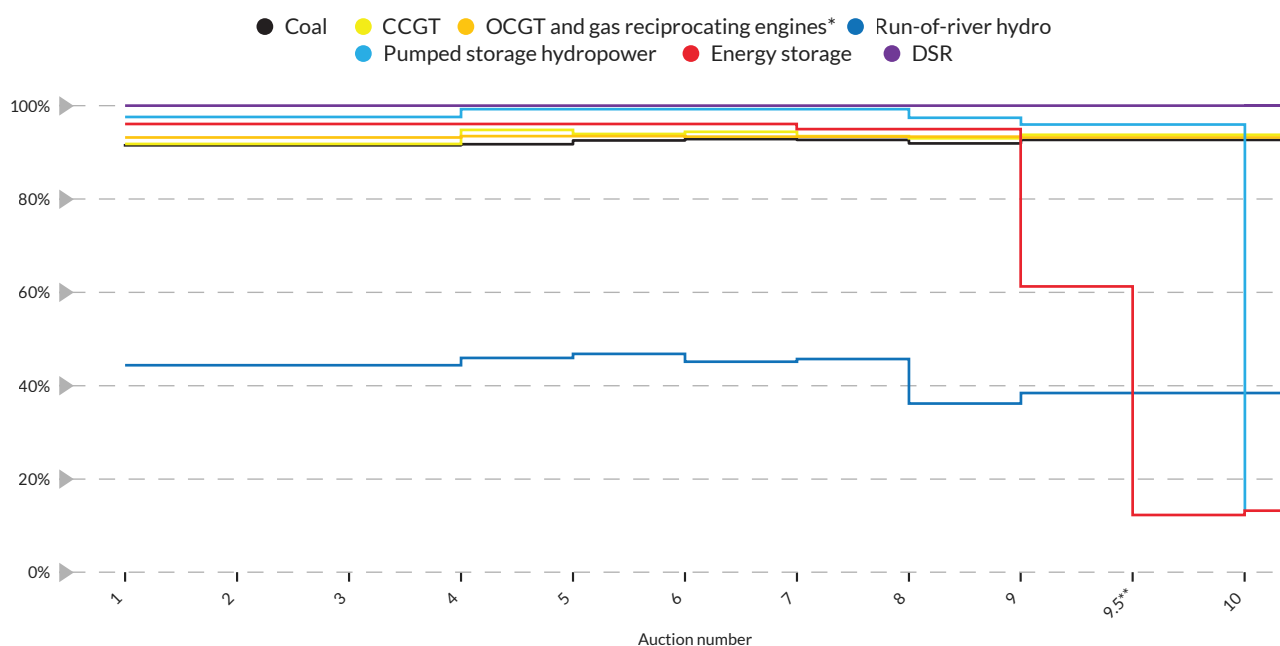
Battery electricity storage

Battery storage systems (BESS, battery energy storage systems) are needed in the power system at multiple levels of network operation. For a short period, BESS began to develop intensively within the capacity market framework, but as they competed with generating units, their role was reduced. In subsequent auctions, their availability correction factor (KWD) was lowered, both in the additional auction for the 2029 delivery year and in the main auction for the 2030 delivery year. Despite this, in the most recent main auction new storage units were awarded 0.7 GW of capacity obligations. The next chart shows how the KWD changed for selected technologies across individual auctions.

In 2027, the first new BESS with capacity contracts will enter the system. However, the largest volumes of capacity will appear in 2028–2030. In total, around 5.1 GW of capacity obligations will be added during this period, corresponding to 11.3 GW of achievable capacity.

Chart 4. Changes in the availability correction factor in successive main auctions for selected technologies

[Go to the interactive chart](#)



Source: own elaboration by Forum Energii based on capacity market auction results, media announcements, enquiries to companies, and internal assumptions.

* OCGT and gas reciprocating engines.

** Auction 9.5 denotes the additional auction for the year 2029.

Chart 4 also presents changes in the KWD for pumped storage power plants. Until the supplementary auction, they were treated on a par with conventional units. However, in the most recent main auction, they were treated in the same way as battery storage.

Foreign capacity

Foreign capacity is subject to specific rules in the capacity market. It may receive contracts of no more than one year, the value of which, depending on the region of origin⁸, does not exceed the prices awarded to Polish units. The capacity market has secured between 0.6 and 1.6 GW of foreign capacity in 2025–2030. Their participation is consistent with the Treaty principle of building an integrated EU internal energy market, ensuring a level playing field and limiting costs.

DSR

Electricity generators are not the only ones that can participate in the capacity market. Since the very beginning of the mechanism, demand side response (DSR) has also been present. These units, like foreign units, may receive contracts for no longer than one year. In 2021–2030, these contracts cover between 0.7 and 1.7 GW.

The last main auction with capacity contracted until 2046

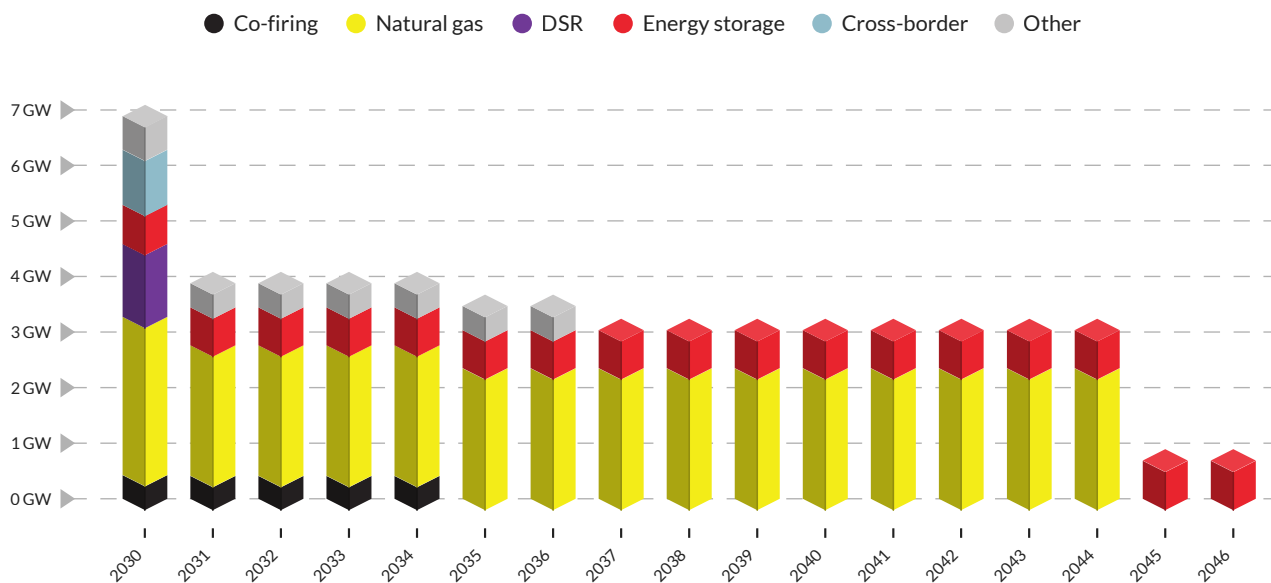
On 11 December 2025, the last main capacity market auction (No. 10) was held to secure additional capacity from 2030 onwards. Initially, competition in this auction was expected to be high, with submitted projects amounting to around 12 GW. Ultimately, however, 9 GW of units participated in the auction. Some of those that remained withdrew as the price declined and, as a result, the auction concluded in the second round at a price of PLN 465.02/kW/year. A total of 6.9 GW of capacity obligations for 2030 were contracted.

More than 2.8 GW of the contracted capacity consists of gas-fired units, of which 2.3 GW will be new OCGT units (appearing for the first time among winning bids) or gas engines. The growing interest in these technologies shows that investors recognise the high future demand for system flexibility. However, due to their lower efficiency, the contracted units are also characterised by higher emissions. As a result, the contracts awarded to them cover a period of 15 years, rather than 17 years as in the case of CCGT technology. The new gas-fired units will therefore receive support until the end of 2044.

A further 0.7 GW was awarded to energy storage. This means that, due to the low KWD, the **achievable capacity** of these storage units will amount to around 5.3 GW. In addition, hydro units and biomass-fired units also appeared, as well as foreign units and DSR. The following chart presents the results of the last main auction.

The total support that units will receive over the entire duration of their capacity contracts will amount, including indexation, to approximately PLN 29.4 billion. This was the second most-expensive auction in the country—a larger volume of capacity (more than three times as much) was contracted only during the first main auction.

⁸ Three zones are distinguished: the transmission system of the Kingdom of Sweden, the transmission system of the Republic of Lithuania, and the synchronous profile zone.

Chart 5. Results of the 10th main auction by technology
[Go to the interactive chart](#)


Source: own elaboration by Forum Energii based on capacity market auction results, media announcements, enquiries to companies, and internal assumptions.

How much capacity is needed in the capacity market?

We have presented the experience of the Polish capacity market in recent years and the investments associated with this mechanism. How these translate into security of electricity supply in the country and the cost situation of consumers depends on the way costs are redistributed and on the optimisation of the entire energy transition process in Poland. Dispatchable capacity constitutes only a small, albeit important, part of this process.

The basis for assessing the security of the European transition is the European Resource Adequacy Assessment (ERAA), prepared by ENTSO-E. The methodology, assumptions and results of the analysis are subject to consultation and approval by ACER, the agency bringing together energy regulators in the European Union. Input to the ERAA is provided by national system operators, which regularly conduct a National Resource Adequacy Assessment (NRAA).

What is the methodology for assessing capacity adequacy?

The capacity adequacy assessment methodology makes it possible to estimate the probability and scale of potential shortfalls in meeting demand in the national system and in individual systems within the European synchronous area, across a wide range of weather and demand scenarios.

It is important how a given operator approaches the adequacy assessment methodology. Under a conservative approach, the focus is primarily on dispatchable generation capacity—many system operators in the European Union choose such a solution because they have control over these sources. However, it is equally important to take into account other factors affecting system balance, such as:

- **RES** – relying on RES capacity targets included in strategic documents may lead to an overestimation of the need for dispatchable capacity, as these targets are often underestimated in practice (including in the most recent documents). For example, in the draft update of the National Energy and Climate Plan of December 2025, the level of PV capacity in the WAM scenario for 2030 would be realistic only if the pace of photovoltaic development were to fall by around 70% compared to recent years. A similar issue is visible in the national adequacy assessment: in its 2024 analysis, PSE assumed 32.7 GW of RES for 2025, whereas by the end of 2025 RES capacity was close to 40 GW⁹. Such a divergence between forecasts and actual market developments may result in excessive investment in dispatchable capacity and, consequently, a higher capacity fee for consumers.

⁹ Forecast of achievable capacity levels in the National Power System, based on data from PSE, URE, and the Ministry of Climate and Environment (MKiŚ).

- **Energy storage** – adopting up-to-date technical parameters (power/capacity/efficiency) and prices, as both the technology and the market are evolving very dynamically.
- **Demand flexibility** – taking into account not only industry but also the potential of individual consumers (dynamic tariffs) and new sources of flexibility, for example, data centres/computing facilities, combined heat and power plants, industry, or EVs.
- **District heating** – once heat and electricity production are decoupled (for example, through heat storage, electrification, or changes in sources), the sector can provide capacity and flexibility in hours and seasons in which it has not previously operated.
- **Transmission capacity** – assessment taking into account the full potential use of interconnectors and the conditions of their availability.
- **Fuels** – their technical and economic availability should be assessed in the context of their target role in the generation mix (for example, assumptions limiting growth in gas consumption) as well as structural cost and supply conditions, as in the case of coal, where declining production results in rising unit costs.

Good planning of adequacy and capacity balance at the national level is therefore of crucial importance. Detailed assumptions at a lower level also become key, such as the forced outage rates of conventional units, realistic weather scenarios, fuel price assumptions, or cross-border analysis of available commercial capacity.

Methodological differences in adequacy assessment and their impact on capacity market costs

In November 2024, PSE prepared the National Resource Adequacy Assessment for 2025–2040¹⁰. In February 2025, ACER published an opinion¹¹ on the differences between the Polish NRAA and the ERAA. It indicates that PSE's analysis diverges in certain aspects from European guidelines and overestimates capacity needs.

According to an analysis carried out at the European level in ERAA 2023, the loss of load expectation (LOLE)¹² indicator—with a standard maximum of 3 hours per year—is exceeded in only one year, by 5.5 hours in 2033. By contrast, the national NRAA indicates significant exceedances in every year of the analysis (for example, for 2028 it is 33.3 hours according to the NRAA, but 1.8 hours according to the ERAA).

The national adequacy assessment provided the justification for Poland's request to grant a derogation allowing high-emission units to participate in the capacity market until 2028. The European Commission assessed this request positively; however, in line with ACER's opinion, it called for adjustments to the Polish approach to adequacy assessment in three areas:

1. **The NRAA should consider the export capabilities of generating units in Poland** – assuming zero electricity exports to neighbouring countries may artificially reduce generators' revenues.
2. **Profitability analyses of generating units should consider a longer time horizon for revenues and costs** (that is, 10 years instead of one year) – the NRAA assumed that a unit incurring losses after one year would be withdrawn. This recommendation is intended to avoid the premature closure of a generating unit that could prove cost-effective over a longer period.
3. **The maintenance schedules adopted in the NRAA differ from those used in the ERAA** – PSE should justify its assumptions in this respect and demonstrate that they result from national specificities. More frequent maintenance outages may also reduce generators' profits.

An updated document incorporating ACER's comments has not yet been published, despite two top-up auctions having already been conducted. This may result in overstated capacity needs and a higher capacity fee.

¹⁰ PSE, Publication of the report in accordance with Article 15(i) of the Energy Law Act, 2024, <https://www.pse.pl/-/publikacja-raportu-zgodnie-z-art-15-i-ustawy-prawo-energetyczne>.

¹¹ Acer, *Opinion No 01/2025 of the European Union Agency for the Cooperation of Energy Regulators of 3 February 2025 on the differences between the national resource adequacy assessment of Poland and the 2023 European resource adequacy assessment, 2025*, https://www.acer.europa.eu/sites/default/files/documents/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER_Opinion_01-2025_Polish_National_Resource_Adequacy_Assessment.pdf.

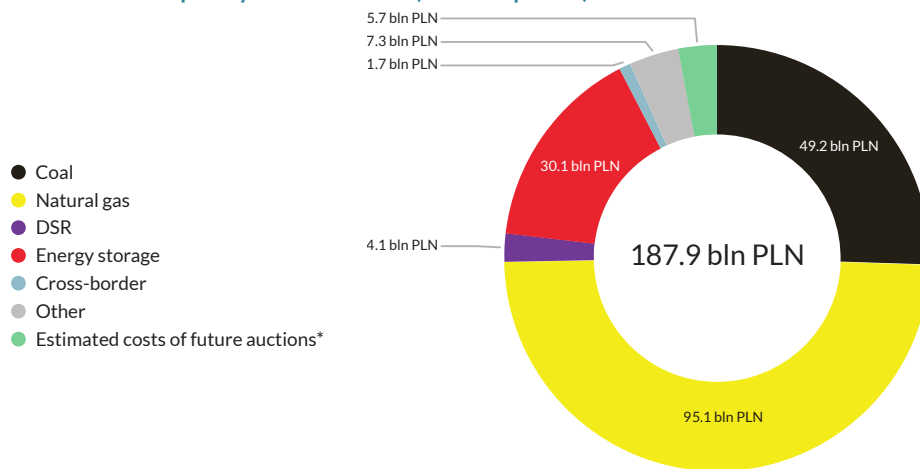
¹² The LOLE indicator defines the total duration of capacity shortfalls over a year.

Costs of the capacity market

The capacity market constitutes a commitment of more than 20 years, the total cost of which for 2021–2046 will amount to at least PLN 187.9 billion in current prices, or on average PLN 7.2 billion per year – including estimates for future auctions. In the first years of operation, the mechanism supported existing units or encouraged the refurbishment of coal-fired units. The largest number of new installations supported by the capacity market will begin to enter the system from 2029 onwards. Looking at the full period of the scheme’s operation, the main beneficiaries are gas-fired sources (50.7%, or PLN 95.1 billion in current prices), followed by hard coal (26.3%, or PLN 49.2 billion in current prices), and then energy storage (16%, or PLN 30.1 billion in current prices).

The following charts present the estimated total costs of the capacity market in 2021–2046, including future auctions. The parameters of these auctions (additional and top-up) are not yet known, so their cost can only be estimated. If capacity demand in 2027–2030 will be the same as in 2026 and that contract prices will remain at a similar level, costs of several billion PLN can be expected. Most of these funds will most likely be allocated to coal-fired units.

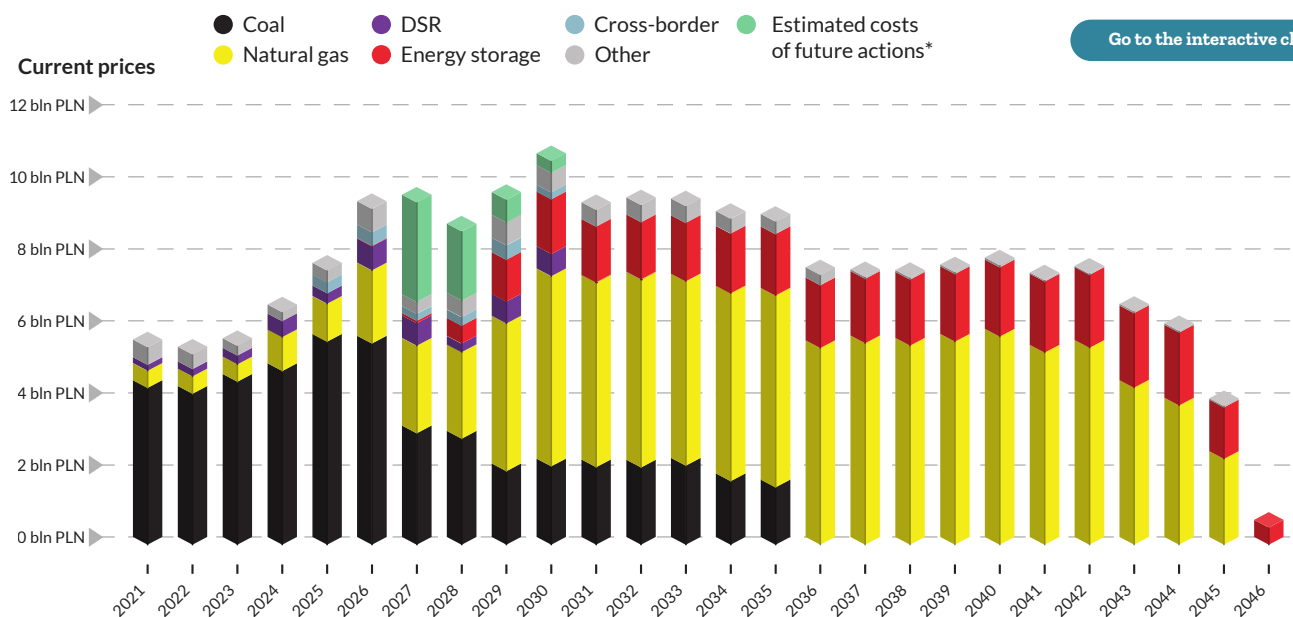
Chart 6. Total capacity market costs (current prices)



[Go to the interactive chart](#)

Source: own elaboration by Forum Energii based on capacity market auction results, media announcements, enquiries to companies, and internal assumptions. * Estimates refer to supplementary auctions for 2027–2028 and additional auctions for 2027–2030. Capacity demand is assumed to be equal to the level of the last fully contracted year, i.e. 2026.

Chart 7. Annual capacity market costs by technology

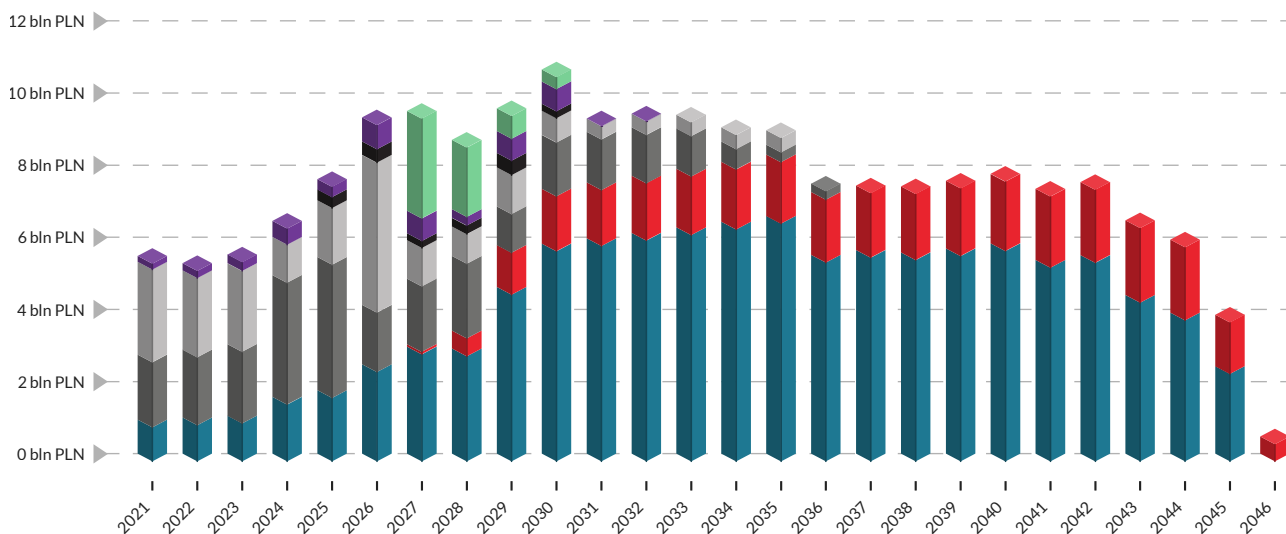


[Go to the interactive chart](#)

Source: own elaboration by Forum Energii based on capacity market auction results, media announcements, enquiries to companies, and internal assumptions. * Estimates refer to supplementary auctions for 2027–2028 and additional auctions for 2027–2030. Capacity demand is assumed to be equal to the level of the last fully contracted year, i.e. 2026.

Chart 8. Annual capacity market costs by type of capacity market unit
[Go to the interactive chart](#)

- New build generation units
- Refurbished
- Cross-border
- Estimated costs of future auctions*
- New build energy storage
- Existing
- DSR

Current prices


Source: own elaboration by Forum Energii based on capacity market auction results, media announcements, enquiries to companies, and internal assumptions.
 * Estimates refer to supplementary auctions for 2027–2028 and additional auctions for 2027–2030. Capacity demand is assumed to be equal to the level of the last fully contracted year, i.e. 2026.

The high costs of the capacity market result from steadily increasing auction starting prices and the limited availability of new projects. When the capacity of the projects offered is lower than the required demand, the auction concludes in the first rounds at a very high price. For example, in the supplementary auction for the 2029 delivery year (column “9.5” in the charts below), demand amounted to 5.2 GW, while only 4.5 GW of units participated. As a result, the auction ended in the first round at the highest price to date, PLN 534.1/kW/year.

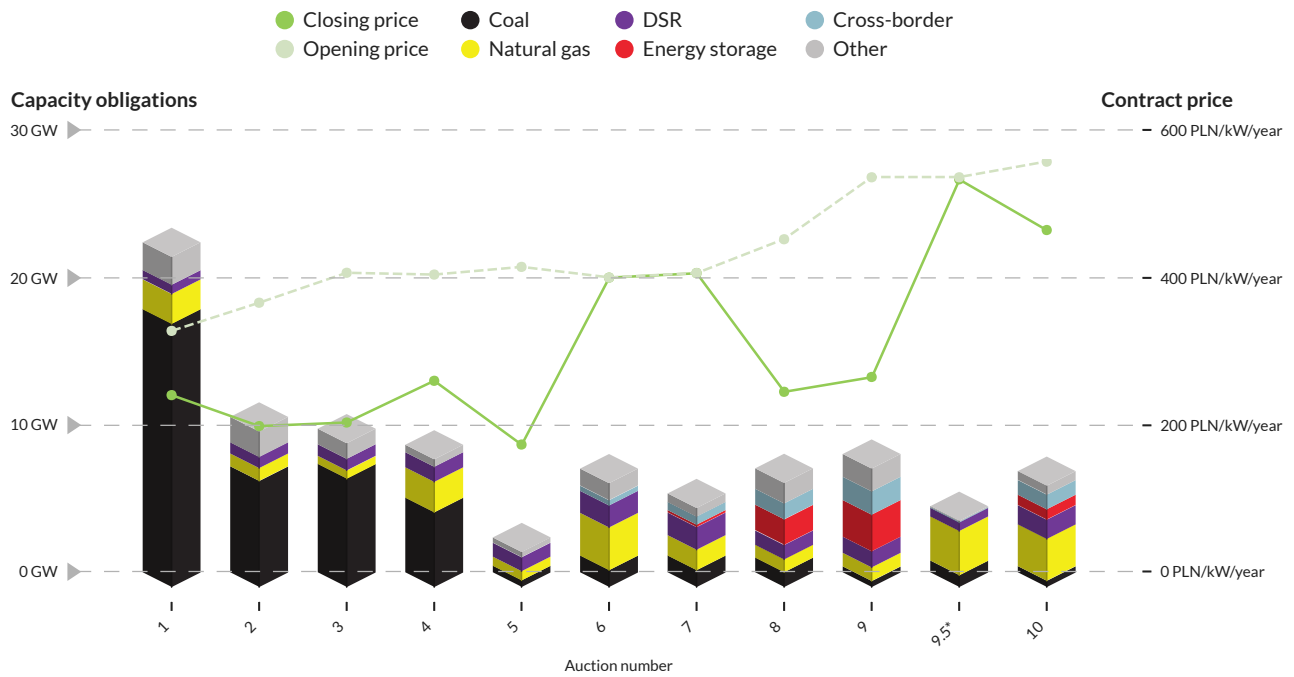
The decline in project availability results from, among other things, the previously mentioned change in the method of calculating the availability correction factor, which was intended to push energy storage out of the capacity mechanism.

Another problem of the capacity market, in addition to its high costs, is **regulatory uncertainty**, which increases financing costs. Depending on the operator’s needs, the availability correction factor may change significantly, even though it is theoretically a fixed characteristic of a given technology and largely determines the profitability of an investment. **The capacity market mechanism therefore does not ensure full competitiveness**, which may lead to overstated system costs.

Contract prices, as well as the opening prices of the most recent main auctions together with the awarded capacity obligations, are presented in the following charts.

Chart 9. Capacity obligations and contract prices by technology

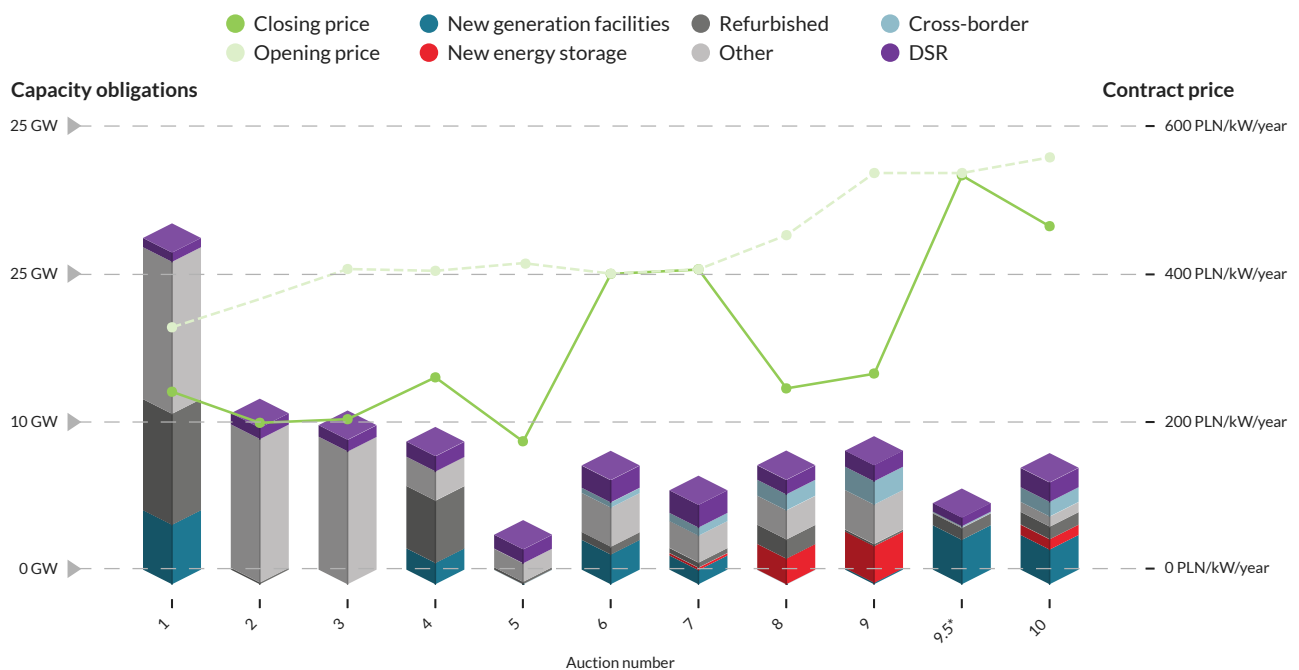
[Go to the interactive chart](#)



Source: own elaboration by Forum Energii based on capacity market auction results, media announcements, enquiries to companies, and internal assumptions.
* Auction 9.5 denotes the additional auction for the year 2029.

Chart 10. Capacity obligations and contract prices by type of capacity market unit

[Go to the interactive chart](#)



Source: own elaboration by Forum Energii based on capacity market auction results, media announcements, enquiries to companies, and internal assumptions.
* Auction 9.5 denotes the additional auction for the year 2029.

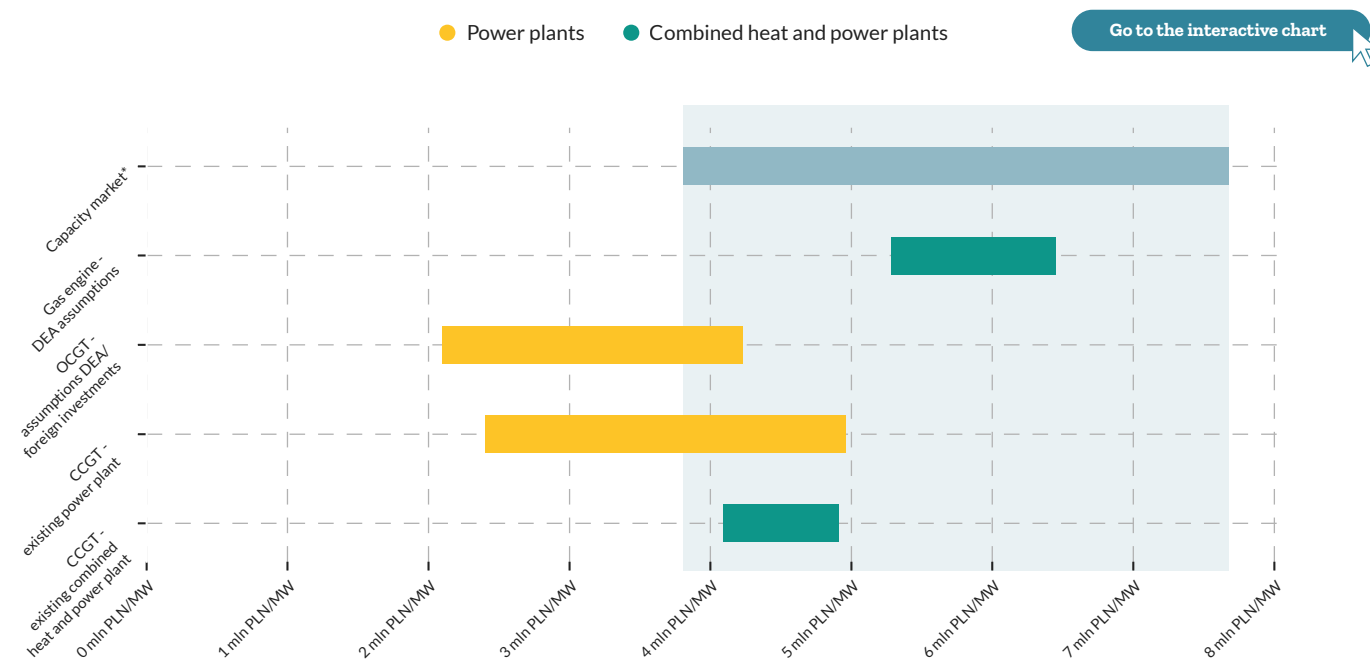
The clearing price of the main (and supplementary) auctions applies to the first delivery year. Units that have been awarded multi-year contracts may expect annual indexation of these prices by the consumer price index (CPI). As a result, the remuneration they receive (in current prices) will increase over time.

For many years, the capacity market supported existing coal capacity, postponing demand for gas capacity. As a consequence, this has led to a clustering of projects. New gas capacity is now being procured at inflated costs, mainly due to significantly greater competition for available resources and contractors, both on the domestic market and across Europe (for example, in Germany).

The following charts compare capital expenditure for individual gas technologies with the total level of support resulting from the capacity market for 17-year contracts. The values obtained indicate that total remuneration from the capacity market for most projects significantly exceeds their capital expenditure¹³. An economic analysis¹⁴ of CCGT projects under Polish conditions, which could enter operation in 2030 as brownfield investments (at an existing power plant), assuming a high WACC of 14.5%, indicates a positive NPV.

The chart presents a comparison of capital expenditure for different gas technologies, based on databases and actual investments, with the support obtained by new gas-fired units from the capacity market mechanism.

Chart 11. Comparison of capital expenditure with total support from the capacity market (current prices)



Source: Energy Forum's own study based on data from DEA, NREL, and press releases.

* The value reflects the range of support levels for new gas-fired units within the capacity market, calculated as the sum of contracted auction values, cumulated over the entire contract period, and divided by the total contracted capacity.

- Horizontal segments represent the range of values for the analyzed projects, while dots indicate representative values.
- Actual power plant designs: Dolna Odra (B9, B10), PGE Rybnik, Adamów (B6), Grudziądz (B1), Ostrołęka (B1), Koźnice (B1, B2).
- Actual CHP plant designs: CCGT Gdańsk, EC Stalowa Wola, Żerań (B13), CCGT Włocławek.

High contract prices and indexation mean that the **unit cost of gas capacity will increase from PLN 281.0/kW in 2025 to PLN 778.6/kW in 2045** in current prices. By comparison, the contracted storage units will cost almost half as much in 2045, i.e., PLN 454.2/kW.

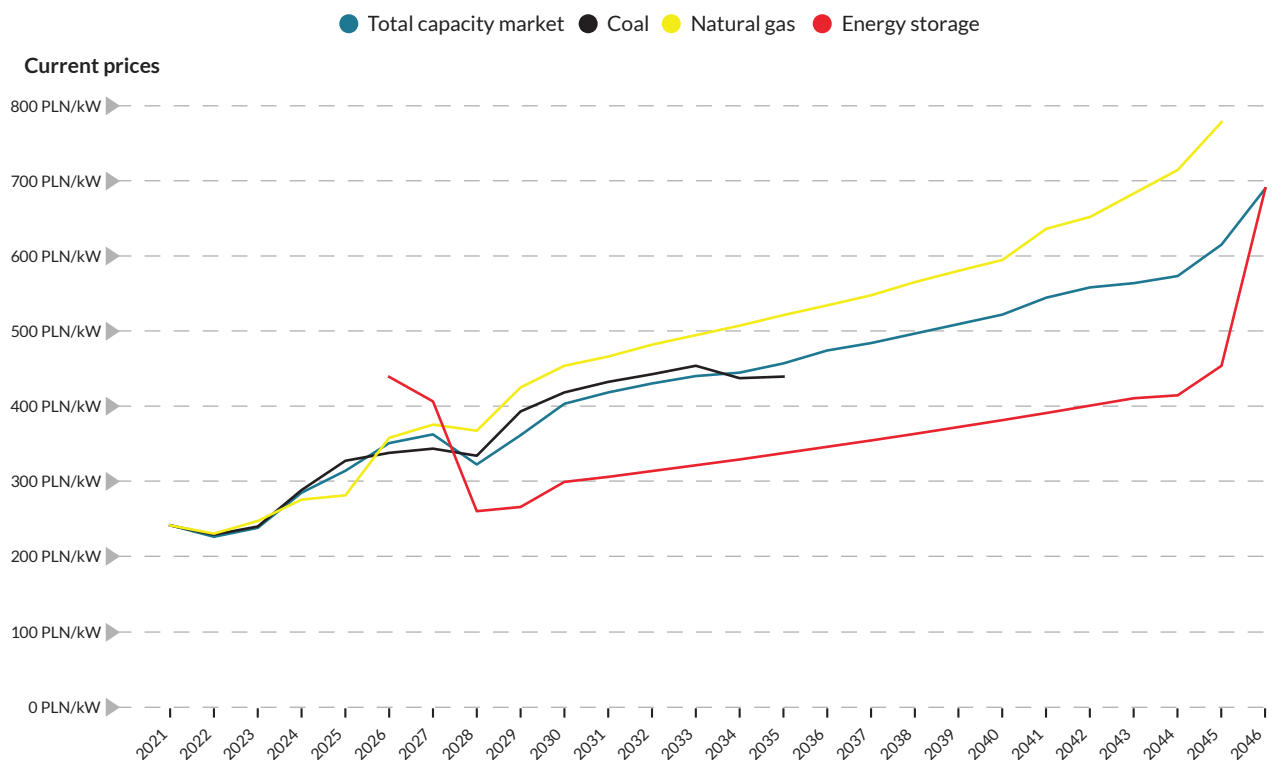
The chart presents the unit cost of the main technologies in individual years, both for the entire capacity market and by technology. The unit cost was calculated as the ratio of the total cost of a given technology to the contracted capacity. The sharp increase in storage costs in 2046 results from the high clearing price of the 10th main auction.

¹³ This comparison is indicative, as it is not clear what costs the investor incurs beyond capital expenditure. These may also include financing costs, investment risks, contingencies for regulatory uncertainty, or other components reflecting the individual assumptions of auction participants.

¹⁴ Aurora Energy Research, *The Race to Clean Power Baseload in CEE: Storage, Nuclear, Gas and their Impact on Renewables Financing*, presentation delivered by Kora Stycz at the Aurora Energy Transition Summit Warsaw, 2026, <https://cms-production.auroraer.com/wp-content/uploads/2026/02/Kora-Stycz-Keynote-Presentation.pdf>.

Chart 12. Unit cost of selected technologies in the capacity market per capacity obligation

[Go to the interactive chart](#)



Source: own elaboration by Forum Energii based on capacity market auction results, media announcements, enquiries to companies, and internal assumptions. Contracting status after the main auction for the year 2030.

The capacity market is not transparent

Due to the non-transparent publication of auction results, the capacity market may be perceived as a closely guarded secret. Yet, it is a mechanism for granting public support to electricity generators, intended to ensure capacity adequacy, and its costs are and will be borne by all electricity consumers.

Example

About the unit designated as JRM/989, the only information available is that it is a new capacity market unit with identification number 989, owned by ENEA ELKOGAZ. From 2029, for 17 years it will be obliged to maintain capacity of nearly 610 MW and will receive remuneration of PLN 534/kW/year, that is, PLN 6.8 billion of public support (in current prices)—one of the higher amounts in the history of this mechanism. And that is essentially all the available information.

It is not known what type of generating unit it is, nor what its current achievable capacity is or—in the case of new installations—what is planned. We also do not know where the unit is located or even what fuel it will use. This information could be useful when attempting to model the future system, monitor progress in meeting the objectives of strategic documents, or simply help oversee system operation.

Only after an in-depth analysis of data dispersed across media sources can it be established that JRM/989 most likely means public support for a new CCGT natural gas-fired unit in Koziernice with a gross capacity of 668 MW. In this case, it is relatively easy to connect the facts, as the investment has been widely discussed. But what exactly lies behind the support granted to the range of less well-known companies?

There are more than a thousand similar units within the capacity market. They participate in different types of auctions, which further complicates an understanding of the consequences of this mechanism for energy security and the state's energy policy.

Costs of the capacity market in electricity bills

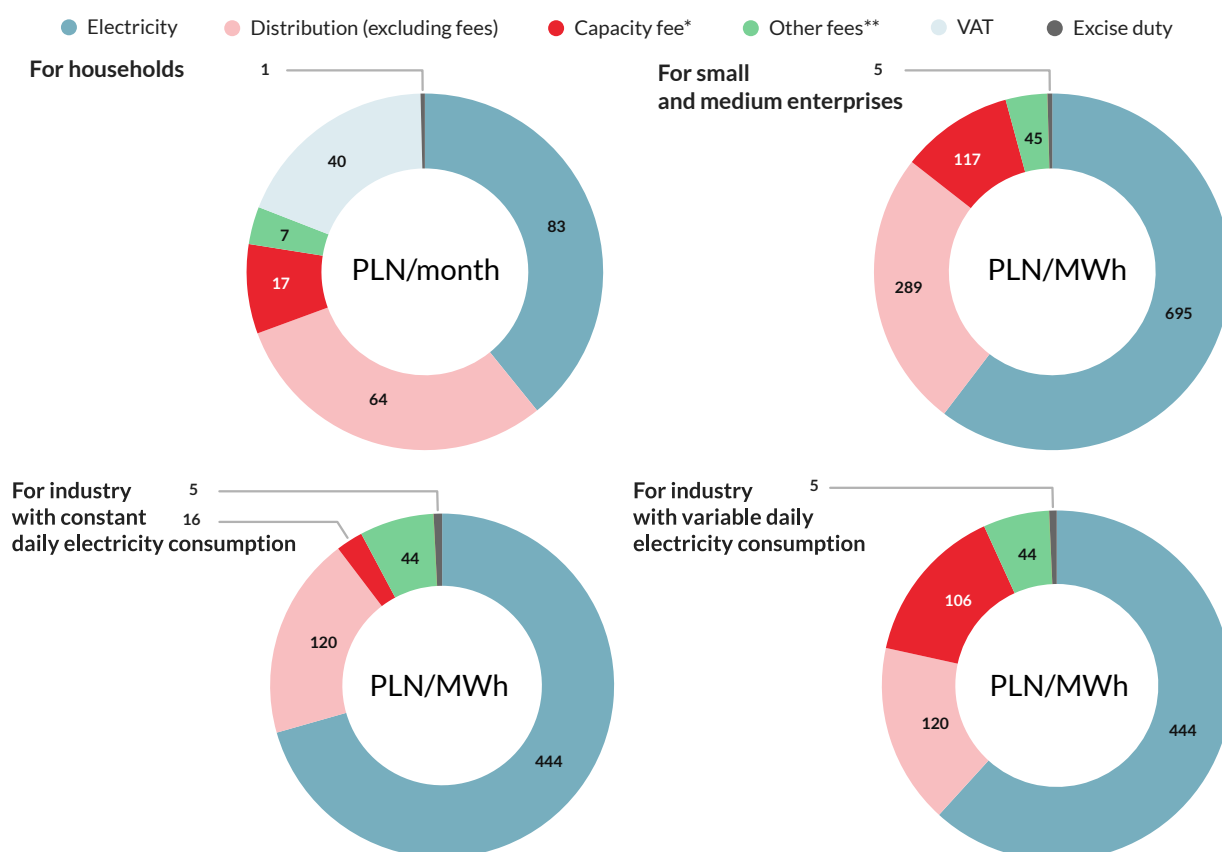
The costs of operating the capacity market are passed on to consumers in the form of the so-called capacity fee, which constitutes a separate component of the electricity bill. Its level is determined annually by the President of the Energy Regulatory Office (URE) and depends on the consumer group and their electricity consumption profile. For households, fixed rates apply (until the end of 2027, after which a change will take place¹⁵), while for businesses variable rates apply, depending on the volume of electricity consumed during peak demand hours, that is during selected hours of the day announced each year by the President of URE.

The share of the capacity fee in total energy costs also differs due to different methods of calculating energy prices, distribution charges, and other components of the bill for individual consumer group.

- **Households** – in 2026, the capacity fee for an average household will increase from PLN 11.4 to PLN 17.2 per month, accounting for 8.1% of the household's electricity bill.
- **Small and medium-sized enterprises** – businesses with contracted capacity above 16 kW pay for the volume of electricity consumed between 07:00 and 21:59 on working days (peak demand hours). The rate for 2026 is PLN 219.4/MWh and accounts for approximately **9.3% of the electricity bill**.
- **Industry** – for some industrial plants, the capacity fee in 2026 is the same as for small and medium-sized enterprises, that is PLN 219.4/MWh during peak demand hours, accounting for **14.7% of their bill**. However, plants characterised by a constant daily electricity consumption profile (mainly heavy industry) may have their fee reduced to as low as PLN 37.3/MWh, in which case the fee accounts for **2.5% of the electricity bill**.

Chart 13. Electricity bills in 2026

[Go to the interactive chart](#)



Source: own elaboration by Forum Energii:

- for households – based on data from PGE Obrot S.A. (G11 tariff), PGE Dystrybucja S.A. (G11 tariff), URE, MKiS.
- for small and medium enterprises – based on data from PGE Obrot S.A. (C11 tariff), PGE Dystrybucja S.A. (C11 tariff), URE, MKiS.
- for industries – based on data from TGE, PGE Dystrybucja S.A. (B21 tariff), URE, MKiS.

* The capacity charge for businesses and industry is calculated based on electricity consumption during peak hours on working days.

** Quality fee, RES, cogeneration.

15 The division into final consumers settled on a fixed (lump-sum) basis and other consumers settled on kWh consumed during peak demand hours will apply until the end of 2027. From 2028, all electricity consumers will be settled on the basis of kWh consumed during peak demand hours.

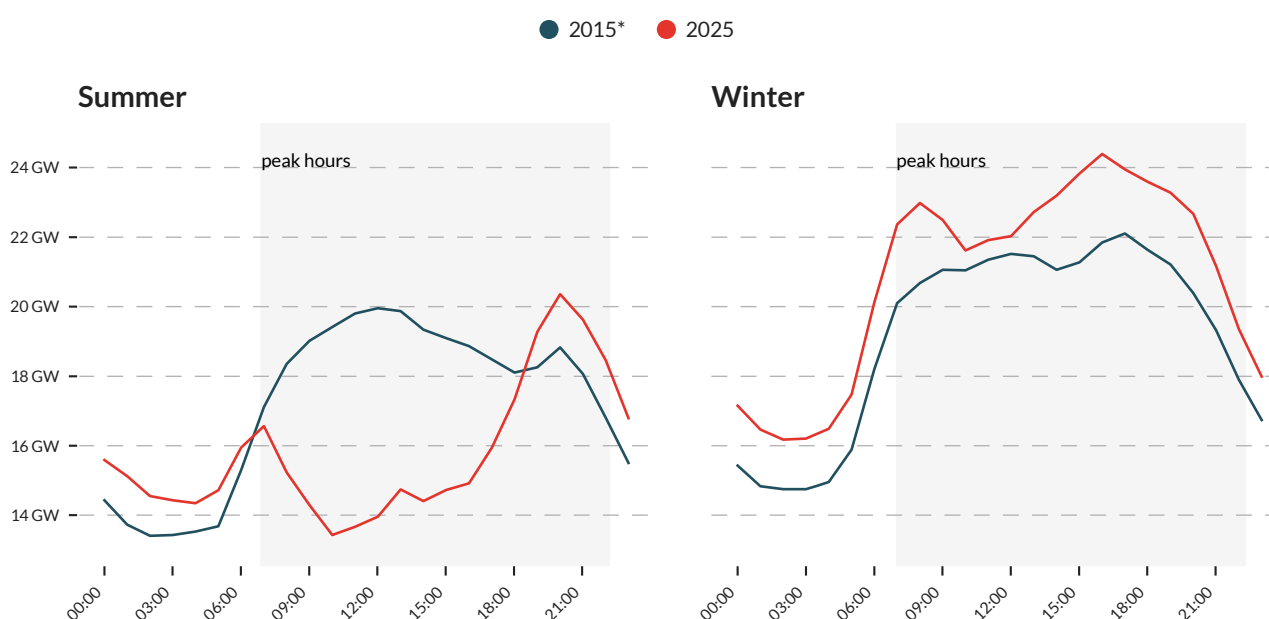
The way in which the capacity fee is calculated favours consumers with a steady daily electricity consumption profile. Those with the flattest profile may benefit from a reduction of up to 83%¹⁶.

Since August 2024, a significant share of individual consumers have been able to receive price signals from the electricity market directly through dynamic tariffs, which encourage higher consumption during hours of low wholesale prices. From the beginning of 2028, the incentive from the capacity fee, rewarding reductions in consumption during peak demand hours, will also apply to households. However, this pricing method is more suited to the energy model of the previous decade, when the system did not include such a large number of photovoltaic installations, which have fundamentally changed the profile of residual demand (that is, demand for conventional power plants, or net demand in the National Power System after subtracting wind and PV generation).

This is illustrated by the next chart, which presents maximum residual demand in each hour of the analysed period, indicating when the system requires the highest level of dispatchable capacity. A clear shift in the profile can be observed, particularly in summer when the highest values move from the broad interval between 07:00 and 21:59 to short morning and evening peaks. The design of the capacity fee should take these changes into account.

Chart 14. Maximum gross residual demand for each hour in 2015 and 2025

[Go to the interactive chart](#)



Source: own elaboration by Forum Energii based on PSE data.

Summer denotes the period from 1 June to 31 August, and winter - from 1 December to 28/29 February of the following year. Residual demand is calculated as the difference between the National Power System demand and the planned wind and PV generation, based on Current Daily Coordination Plans. * In June 2024, PSE changed the reporting convention for electricity consumption data: net demand is now reported instead of gross demand. As a result, data from before and after the change cannot be compared directly. Therefore, the chart shows net values estimated for 2015 based on the average annual auxiliary consumption of power stations.

Periods in which—given the still limited flexibility of the National Power System—it becomes necessary to curtail RES generation also pose a challenge for the electricity system. The scale of this phenomenon is increasing: in 2025, mainly for balancing reasons, around 1.4 TWh of RES generation was not fed into the grid. This is almost twice as much as in 2024.

Curtailment occurs primarily during the hours defined in the Capacity Market Act as peak demand hours (in URE communications: working days 07:00–21:59) – these hours accounted for 84% of curtailed energy in 2024 and 79% in 2025. **In this context, the capacity fee, which incentivises reductions in consumption precisely during these hours, operates contrary to signals from the electricity market. At times indicating excess generation, it should be temporarily suspended in order to encourage short-term increases in demand.**

¹⁶ Pursuant to Article 70a of the Capacity Market Act, the capacity fee rate is multiplied by one of four values of factor A, depending on the difference between average electricity consumption during peak demand hours and average electricity consumption during non-peak hours on working days. These factors are: 0.17 for consumers with an average difference <5%; 0.5 for consumers with an average difference <10%; 0.83 for consumers with an average difference <15%. For other consumers, i.e., with an average difference ≥15%, this factor equals 1.

The **capacity fee** rewards a uniform electricity consumption profile, while other instruments encourage flexible consumption – varying throughout the day and adjusted to prevailing system conditions. An example is dynamic tariffs, where the electricity price in each hour reflects Day-Ahead Market (DAM) quotations and incentivises shifting consumption to cheaper hours.

The following charts present standard electricity consumption profiles in different tariff groups together with information on the required daily variability that would allow consumers to qualify for a reduced capacity fee category. It turns out that even the G12 tariff group, characterised by a flatter consumption profile, does not meet the requirements of any of the more favourable categories. This demonstrates how difficult it is to meet the criteria for assignment to categories K1–K3. For this reason, we assume that mainly large energy-intensive consumers (in A tariffs and part of B tariffs) with constant electricity consumption qualify for these groups

Chart 15. Daily hourly electricity consumption profile

[Go to the interactive chart](#)

● K1 ● K2 ● K3 ● K4 ● Profile G11 ● Profile G12 ● Profile C11 ● Profile B11/B12

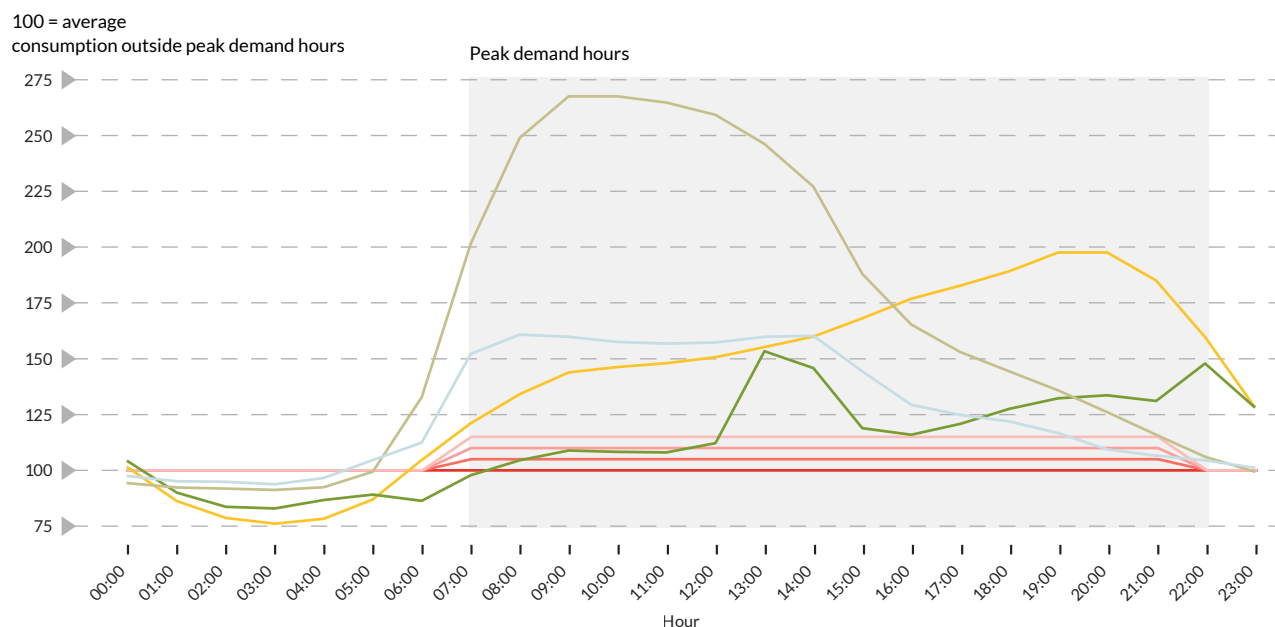
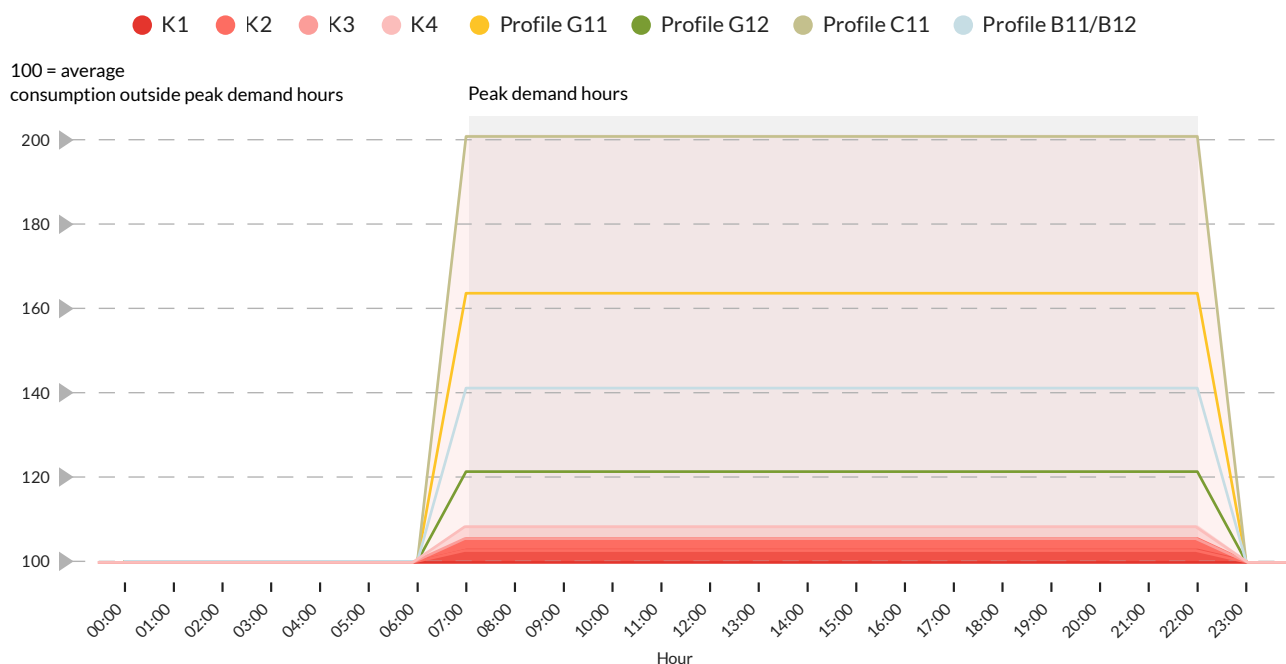


Chart 16. Simplified electricity consumption profile divided into peak demand and off-peak hours

[Go to the interactive chart](#)



Source: own elaboration by Forum Energii based on ENEA data.

Consumers are assigned to specific categories based on the difference between average consumption during peak demand hours and average consumption during other hours.

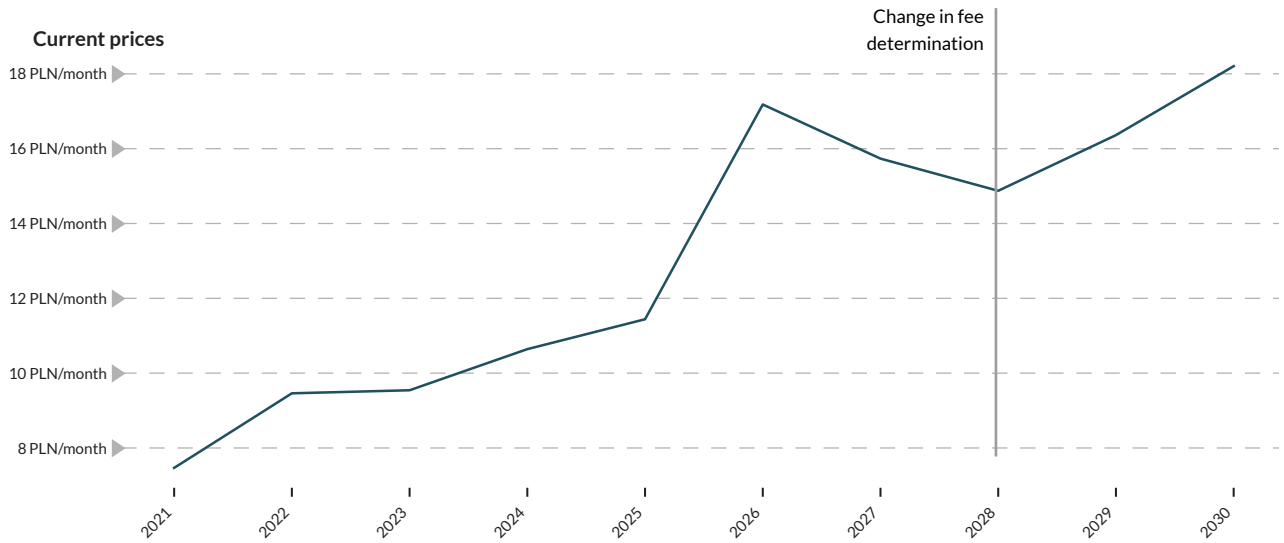
- K1 – consumers with a difference of <5% with a fee reduction of 83%.
- K2 – consumers with a difference of <10% with a fee reduction of 50%.
- K3 – consumers with a difference of <15% with a fee reduction of 17%.
- K4 – consumers with a difference of >=15%.

The charts present electricity consumption profiles on working days for selected tariffs. The first illustrates the daily hourly consumption profile. The second is a simplified model dividing the day into peak demand and off-peak hours. It is this division that determines whether a consumer qualifies for one of the four categories (K1–K4), which determine the level of the reduction in the capacity fee.

Estimated capacity market costs in 2030 may reach as much as PLN 10.7 billion (in current prices). Taking into account the change in the method of determining the capacity fee for households from 2028 onwards, it can be assumed that:

- in 2027–2029, the capacity fee for households should not increase—in 2030, which is likely to be the most expensive year from the perspective of the capacity market, the fee may amount to PLN 18.2 per month (in current prices), representing an increase of PLN 1.0 per month compared to 2026.
- **other consumers**, including industry, may also experience temporary relief until 2030, when the estimated capacity fee rate will amount to PLN 222.8/MWh (in current prices), that is PLN 3.30/MWh more than in 2026—it should be noted, however, that this fee will be significantly lower for companies with a constant daily electricity consumption profile.

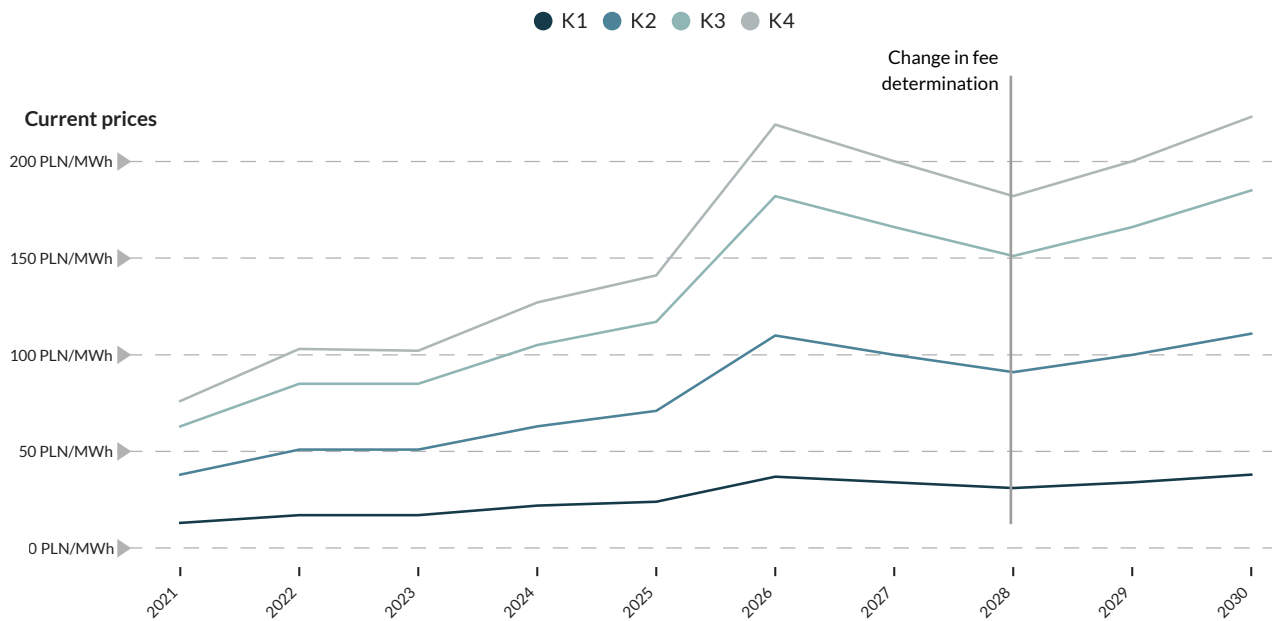
The following charts present how the capacity fee may change in the coming years, taking into account estimated costs of future auctions. Exact values will depend on many factors, including the results of additional and top-up auctions, the structure of electricity consumption by final consumers, and the inflation rate.

Chart 17. Estimated capacity fee for households
[Go to the interactive chart](#)


Source: own elaboration by Forum Energii based on URE, capacity market auction results, media announcements, enquiries to companies, and internal assumptions.

Estimated costs of future auctions are included, i.e. additional auctions for 2027–2030 and supplementary auctions for 2027–2028.

* Until the end of 2027, the capacity fee for households is charged as a flat rate. From the beginning of 2028, it will be charged per kWh taken from the grid during peak demand hours; therefore, a specific annual consumption value had to be assumed for the visualisation.

Chart 18. Estimated capacity fee for other consumers depending on their electricity consumption profile
[Go to the interactive chart](#)


Source: own elaboration by Forum Energii based on URE, capacity market auction results, media announcements, enquiries to companies, and internal assumptions.

Estimated costs of future auctions are included, i.e. additional auctions for 2027–2030 and supplementary auctions for 2027–2028.

Consumers are assigned to specific categories based on the difference between average consumption during peak demand hours and average consumption during other hours.

- K1 – consumers with a difference of <5% with a fee reduction of 83%.
- K2 – consumers with a difference of <10% with a fee reduction of 50%.
- K3 – consumers with a difference of <15% with a fee reduction of 17%.
- K4 – consumers with a difference of >=15%.

Capacity Market 2.0 – recommendations

As we indicated in the report *Power and flexibility, what kind of capacity market does a modern energy system need?*¹⁷ in the Polish power sector, where development is not sufficiently planned and coordinated by public authorities and the dominant role is played by the system operator, it is difficult to expect a departure from the capacity support mechanism. However, every effort should be made to limit the costs of its implementation and to ensure that it reflects the future needs of a market based on variable RES sources, rather than replicating the operating model of the past.

In the above-mentioned report, we presented our recommendations for reforming the capacity market, consisting of the introduction of two different products procured in separate auctions for:

- **flexible capacity**, characterised by a short activation time, responding to dynamic changes in the system; such auctions would be suitable for fast-response technologies, including gas engines, open cycle gas turbines (OCGT), electricity storage (including hybrid configurations with weather-dependent RES),
- **dispatchable capacity**, with an activation time of up to 4 hours, these auctions could be open, for example, to gas units, cogeneration units, and DSR.

Summary

The security of the National Power System depends on a range of factors, including the adequacy of dispatchable capacity, effective market incentives, the condition of the grid, and system flexibility. An important condition is maintaining acceptable costs for consumers and minimising dependence on imported fuels. From this perspective, the capacity market, which provides necessary reserves, is only one element of the security framework, contrary to the domestic debate, which focuses primarily on this mechanism.

Undoubtedly, in its current form the capacity market has bridged the capacity gap for the coming years, buying time to decide on the future role of this mechanism and the shape of the power system. However, its operating costs are high, and lessons must be drawn: persisting with a “capacity at any cost” strategy will translate into a likely higher capacity fee and, consequently, into a loss of competitiveness for the Polish economy.

Given the state’s limited capacity to plan the modernisation of the energy sector, PSE has assumed the role of central planner, subordinating security of supply to its own operational needs. This means a preference for dispatchable capacity, largely regardless of costs and increasing gas imports and exposure to price volatility, with only limited consideration of emissions criteria.

Broad cooperation with market participants is therefore necessary, not only to make better use of existing resources as sources of dispatchable capacity and flexibility but also to design future mechanisms in a way that takes into account both the interests of the power sector and the entire economy.

From the perspective of Poland’s national interests, a comprehensive approach to the overall energy balance is required, including the use of gas in the Polish economy.

In district heating, building heating, and industrial processes using low-temperature heat, electrification should be consistently prioritised, above all through the development of heat pumps and broader use of waste heat and RES. Improving the energy efficiency of the economy is also essential. At the same time, Polish industry and the heat sector can actively support balancing of the National Power System by increasing electricity consumption during periods of surplus generation. This, however, requires adapting the capacity fee to a system with a high share of RES.

At present, it is difficult for the power sector to operate without gas. It is important, however, not to increase the dependence of the Polish economy on gas imports, not least in light of numerous geopolitical tensions. A solution would be a strategy to reduce the share of gas in the buildings and industry sectors (which account for the largest gas consumption) in favour of electrification.

The Polish energy system requires sound diagnosis, transparency, and a clearly defined objective: providing relatively affordable electricity to consumers. Inefficient planning of energy modernisation has been associated in recent years with rising subsidies for the power sector—for coal mining and its use within the capacity market, for CO₂ emissions, and ultimately for consumers, because electricity is too expensive.

¹⁷ Forum Energii, *Capacity and Flexibility: What Kind of Capacity Market Does a Modern Power System Need?*, 2025, <https://www.forum-energii.eu/en/moc-i-elastycznosc-jakiego-ryнку-mocy-potrzuje-nowoczesny-system-energetyczny>.