The Role of Cogeneration Units and Power-to-Heat Sources in Balancing the National Power System and Heat Generation

Report by Polskie Towarzystwo Energetyki Cieplnej (Polish Association of Heat Energy)

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Table of contents

The report is analytical and based on scenarios. The conclusions presented in the report are based on two benchmark heat markets that reflect the material conditions found in Polish district heating systems. For this reason, the results of the analysis may be helpful in assessing trends and transformation effects from a broader perspective of the heating sector; however, their interpretation should take into account the scope of the assumptions, parameters, and scenarios used. References to emissions, costs, environmental performance, and decarbonization pathways apply to the scope of this analysis and do not constitute universal characteristics of all systems, technologies, fuels, or companies.

Preface

Dear Sirs,

Cogeneration is the foundation of large-scale district heating systems and one of the key components of energy security. Cogeneration produces electricity and heat close to off-takers, thereby stabilizing the operation of the National Power System and reducing the need to transmit electricity from remote sources.

This year's report by the Polskie Towarzystwo Energetyki Cieplnej (Polish Association of Heat Energy) represents a new stage in our analyses. For the first time, we demonstrate the role of cogeneration on two complementary levels. The first one is both local and network-based. Using the Rzeszów CHP Plant as an example, we analyze how reducing cogeneration output and the extensive electrification of district heating systems might affect power distribution and load on local power systems. The second level is system-based. It illustrates the consequences of various options for the transformation of district heating systems, particularly with regard to the role assigned to cogeneration, heat generation costs, availability, and need to replace electrical capacities, necessary capital expenditures, fuel consumption, and emissions. This perspective provides a better understanding of the true significance of cogeneration. It is not merely a heat-generation technology—it is an essential system resource whose role will grow alongside the development of renewable energy sources and the electrification of district heating systems.

The transformation of district heating systems cannot be considered in isolation from power systems. As we point out in the report, replacing local cogeneration capacity exclusively with Power-to-Heat technologies—and the resulting increase in electricity off-take—could lead to higher system loads, additional infrastructure costs, and the loss of important local dispatchable capacities. Therefore, the future model of district heating systems should be based on the coordinated use of high-efficiency cogeneration, heat storage, Power-to-Heat technology, and low- and zero-emission fuels.

Presenting this report to you, we also emphasize the need for a stable and predictable regulatory framework for the further development of high-efficiency cogeneration. This is essential for ensuring the security of heat and electricity supplies, optimizing the transformation costs, and promoting faster decarbonization of district heating systems in Poland.

I wish you a pleasant reading!

Marcin Laskowski

President of Polskie Towarzystwo Energetyki Cieplnej
(Polish Association of Heat Energy)

Executive summary

Cogeneration as a cornerstone of district heating in systems Poland

- District heating systems are one of the key components of the national energy infrastructure. Nearly **45% of households** use district heating, which accounts for almost half of the country's population. In urban areas, this share exceeds 60%. Given the scale of use of district heating systems, the way this sector is transformed has a direct impact on energy security, heating costs, and the achievement of decarbonization goals.
- A distinctive feature of Poland's district heating systems is the very high share of cogeneraton (CHP, combined heat and power). In 2024, approximately **64% of district heating** came from cogeneration units, confirming that cogeneration is not only a complementary technology but, above all, forms the basis for the operation of many urban heating systems.
- Cogeneration also plays an important role in the National Power System (KSE). Generation of electricity from cogeneration accounts for approximately **14% of the country's total electricity generation**, and the installed capacity of CHP plants in Poland is approximately **10.8 GW**. This means that cogeneration is both a heating technology and an important power source.

Share of cogeneration in Poland compared to the European Union (EU)

- Poland has one of the largest cogeneration capacities in the EU. According to Eurostat data for 2024, CHP plants **in Poland** generated **approximately 29.2 TWh of electricity and 57.3 TWh of net heat**. In the EU, cogeneration potential is concentrated in a relatively small group of countries. **The largest is in Germany—with approximately 38.5 GWe of power output and 42.0 GWt of thermal output from CHP.** In addition to Germany and Poland, CHP is widely used **in the Netherlands, Italy, Finland, Denmark, Sweden, the Czech Republic, France, and Austria.**
- Unlike in some EU countries, where cogeneration is more closely linked to industry, services, or local building systems, the district heating system model predominates in Poland. Therefore, the CHP transformation in Poland is system-based—it simultaneously affects the security of heat supply, local electricity generation, the operation of power systems, and the transformation costs.
- Across the EU, natural gas is the dominant fuel used in CHP, with a growing share of renewable energy sources and a declining share of coal-based fuels. In Poland, a significant portion of cogeneration capacity is still based on coal-fired units, whose further operation will be limited by regulatory, technical, and economic requirements.

  This shows that the starting point for the transformation in Poland is different from that in many EU countries.

Transformation and limited power replacement of cogeneration units

- Between 2018 and 2024, the installed power output of cogeneration units remained at approximately **10 GWe**, 7.7 GWe of which was accounted for by large-scale CHP plants. In 2024, as far as large-scale combined heat and power plants are concerned, coal-fired units accounted for **4.9 GWe** of installed capacity, gas-fired units for **2.6 GWe**, and the remaining 0.2 GWe was accounted for by units fired with other fuels, including biomass.
- Data on electricity generation indicate a gradual shift in the cogeneration mix toward gas. In 2024, approximately 53% of the electricity generated by large-scale combined heat and power plants came from coal-fired units, approximately 42% from gas-fired units, approximately **4%** from biomass-fired units, and approximately **1%** from units fired by other fuels.
- Electricity generation from coal-fired CHP plants fell by nearly **30%** between 2018 and 2024, reflecting both changing market conditions and the gradual phase-out of coal-fired capacity. Most owners of coal-fired CHP plants declare they will shut them down by **2030–2035** at the latest.
- The full replacement of the current coal-fired capacity with gas-fired cogeneration units may be limited by declining heat sales volumes, a decrease in contracted capacity, and new regulatory requirements, including the **EPS** emissions standard of **270 g CO_2/kWh** for high-efficiency cogeneration, as well as requirements regarding the share of renewable energy sources and waste heat in efficient district heating systems.

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Cogeneration support system

- The support system for high-efficiency cogeneration currently in place in Poland is an important mechanism influencing investment decisions regarding new and significantly retrofitted CHP units. The system operates in accordance with the Act on promotion of electricity from high-efficiency cogeneration. The primary and most important support mechanism provided for by the aforementioned Act is the cogeneration bonus, which is awarded through auctions conducted by the President of the Energy Regulatory Office. The Act also provides for the possibility of granting individual cogeneration bonuses (through a call for applications).

- The maximum period of operational support is 15 years from the date of the first generation and sale of electricity, but no later than December 31, 2048. This means that **units commissioned in the second half of the current decade will remain in the system even after 2035, and investment decisions made today will shape the structure of the district heating and power systems in the 2040s.**

- The results so far indicate significantly greater interest in the auction mechanism than in the individual cogeneration bonus. In 2025, **17 investment projects** received support through auctions, and approximately **99.8%** of the auction budget was allocated. In 2026, the first auction awarded the bonus for **20 additional units,** and the second auction resulted in **22 winning bids** submitted by 15 producers, who were granted nearly **4.4 billion PLN** in support. Simultaneously, calls for applications for the individual cogeneration bonus have not attracted much interest from producers in recent years (no call has been finalized since 2021).

Cogeneration as a local system resource in the National Power System (NPS)

- Cogeneration units are located primarily in cities or on their outskirts, and thus close to areas with high heat and electricity demand. As a result, they reduce the distance between energy generation and consumption, improve the local power balance, relieve the load on high-voltage power systems, and reduce the need to transfer energy from remote sources.

- Local generation in terms of cogeneration **reduces technical losses, reduces the load on system nodes, and may allow for the optimization of grid investments**. Therefore, the value of cogeneration for the National Power System does not result solely from the volume of electricity produced, but from its location, availability, and ability to stabilize system operation.

- **Combined heat and power plants can simultaneously meet local heating needs and supply electricity during periods of limited generation of renewable energy.** In situations with no wind, low sunlight, or high winter demand, CHP can quickly support power balance in the National Power System, while ensuring a continuous supply of heat to urban off-takers.

Flexibility of cogeneration and integration with renewable energy sources

- The growing share of renewable energy sources in the electricity mix drives an increase in demand for flexible resources capable of responding to fluctuations in wind and solar power generation. In this model, combined heat and power plants may serve as a link between the power system and the district heating system.

- Modern district heating systems are technologically complex systems that combine flexible cogeneration units, heat storage systems, Power-to-Heat technologies (electrode boilers, heat pumps, also referred to as P2H), and demand management systems.

- During periods of high RES generation, the district heating system reduces cogeneration output, increases electricity consumption by P2H, and may store heat. During periods of low RES generation, cogeneration units can increase electricity production, thereby supporting the National Power System's power balance and reducing the need to activate less efficient reserve sources.

- **Heat storage systems, which allow the time of heat production to be separated from the time of its consumption, will be indispensable for the future role of CHP plants.** This allows combined heat and power plants to generate electricity during periods of high demand in the National Power System, while ensuring a secure supply of heat.

- Power-to-Heat technologies may serve as a flexible electricity off-taker, utilizing surplus generation from PV and wind and supporting heat generation during periods of low or negative energy prices. The P2H system achieves its highest value when combined with heat storage units and flexible cogeneration.

Two levels of analysis of the role of cogeneration and P2H sources: local systems and system-wide assessment of transformation costs

- This report analyzes and evaluates the role of cogeneration in the transformation of district heating systems at two complementary levels. **The first level is both local and system-wide**—using the example of the Rzeszów CHP Plant, it demonstrates how reducing cogeneration output and increasing the electrification of district heating systems influence power distribution and load on power systems. **The second level is system and economic in nature**—it illustrates the consequences of the transformation of district heating systems in options with and without cogeneration, taking into account not only the cost of heat generation but also the need to replace the missing electrical capacity in the National Power System, including through new gas-fired peak and regulating power sources. As a result, the report highlights both the local system-related effects of reducing the role of cogeneration and the broader implications—in terms of costs, investments, fuel consumption, and emissions—of various energy transition pathways.

Case study based on the Rzeszów CHP Plant—the impact of cogeneration and electrification of district heating on power distribution in power systems

- The report presents a power distribution analysis for the Rzeszów CHP Plant. The purpose of this analysis was to examine what happens in power systems when the local district heating system no longer functions as a local source of electricity and instead becomes a significant off-taker of energy from the National Power System.

- The analysis was performed for two time periods: **2029** and **2035**, comparing two system operation scenarios: operation of the Rzeszów CHP Plant at **137 MW**, and a scenario in which the shutdown of cogeneration units is accompanied by an additional off-take of **130 MW** using the **Power-to-Heat** technology.

- The results show that limiting local generation is not neutral for the power system. In the scenario with a high share of Power-to-Heat sources, overloads occur in the 110 kV system directly connected to the Rzeszów area, and the available take-off capacity for P2H is limited to **80 MW** or **60 MW** for 2029, and, under specific operation status, to **0 MW** for 2035.

- The example of the Rzeszów CHP Plant confirms that the transformation of district heating systems should be analyzed in conjunction with the development of power systems. Replacing local cogeneration with large-scale electricity off-take may increase system loads, reveal infrastructural limitations, and create a need for additional investments by system operators.

Expert economic analysis of the transformation of district heating systems

- Two benchmark heat markets were selected for analysis. They differ in terms of the nature of their heat demand curves, including varying shares of domestic hot water and different levels of demand during transitional and summer periods.

- An economic analysis of options for transforming district heating systems shows that **cogeneration, combined with the use of heat storage units, remains one of the key factors in reducing the cost of heat generation**, as measured by the LCOH (Levelized Cost of Heat—the levelized weighted-average cost of heat generation). In both heat market options analyzed—a small-scale 35 MW system and a large-scale 600 MW system—the options incorporating cogeneration units achieve lower or comparable LCOH values compared to options based solely on separated heat and electricity generation.

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- In the model options analyzed, a higher share of high-efficiency cogeneration was associated with greater potential for reducing heat generation costs, especially when combined with heat storage units and Power-to-Heat technologies. Therefore, the approach to meeting the criteria for an energy-efficient district heating system, taking into account the levels of renewable energy sources and/or waste heat after 2035 has significant cost implications: maintaining the **35% threshold** may necessitate faster and more capital-intensive investments, limiting the use of cheaper cogeneration options, whereas **lowering this threshold to 15%** allows for a higher share of CHP and a gradual increase in the share of renewable sources. **With a volume of 206 830 TJ of heat supplied to system off-takers in 2024 (data from the Energy Regulatory Office), a reduction in generation costs of 3 PLN/GJ translates into potential savings of 620 mln PLN per year, which illustrates the scale of significance of a more flexible regulatory path for transformation costs.**

- The results of the analysis indicate that **phasing out cogeneration and filling the resulting gap in available power in the National Power System solely through the construction of gas-fired units in the power sector** leads to an increase in total costs for the economy. In the scenario where there is no local electricity generation at CHP plants, the same volume of energy must be generated at gas-fired power plants, resulting in **higher natural gas consumption and higher costs for purchasing fuel and CO_2 emission allowances.**

- In the model scenarios compared in the report, based on the assumptions regarding the fuel mix, efficiency, and demand, the cogeneration options showed lower emissions and lower fuel consumption than the separated generation option analyzed, where conventional gas-fired power plants predominate. This is a direct result of the higher overall efficiency of cogeneration, in which the chemical energy of the fuel is used simultaneously to generate both heat and electricity. In a scenario based on gas-fired units and heat sources without CHP, the same amount of useful energy requires a larger volume of gas and generates higher CO_2 emissions.

- An analysis of capital expenditures (CAPEX) shows that **options without cogeneration involve lower initial costs for district heating system**s; however, these savings is only apparent when considering the entire power system. The need to build additional generating capacity at gas-fired power plants shifts part of the CAPEX from the heating sector to the electricity sector, without eliminating the need to bear these costs at the economy level.

- In cogeneration options, **higher capital expenditures for CHP units are offset by lower operating costs**, particularly lower fuel and emissions costs. The analysis shows that, depending on the option and the size of the market, the moment at which costs between the combined and separated models equalize occurs relatively quickly — within 1.5 to 2.5 years — with this period being shorter for larger district heating systems.

- From the perspective of CAPEX structure, it is also important that **cogeneration reduces the need to expand generation capacity in the power sector,** particularly so-called “peakers” that operate during periods of RES shortages. This means that the use of CHP in district heating systems makes it possible to limit the scale of investment in new gas-fired units, which must serve as a reserve for the National Power System.

- **The model of separated heat and electricity generation leads to higher costs across the entire economy** even if the individual components of this model have lower CAPEX. Cogeneration, on the other hand, makes it possible to optimize both capital expenditures and operating costs over the long term, while reducing gas consumption and CO_2 emissions.

- **An evaluation of the role of cogeneration should not be limited to a comparison of costs on the district heating system** side, but should also take into account the costs of supplying electricity to the National Power System. Only this approach makes it possible to capture the actual differences between the combined and separated models, as well as the investment and emissions implications for the entire power system.

Recommendations – Key directions for regulatory change

- It is recommended to take regulatory measures, which should focus on **three equally important objectives: maintaining the continuity of investments in high-efficiency cogeneration, ensuring regulatory predictability for gas and low-emission projects, and aligning national and EU legal frameworks with the actual pace of the transformation of district heating systems.** Without the regulatory changes required to implement these measures, we will face the risk of losing local dispatchable capacities, investment delays, and the loss of our status as efficient district heating systems after 2035.

- The further development of high-efficiency cogeneration requires **maintaining and strengthening support mechanisms** for new and retrofitted CHP units. It is crucial to reallocate unused funds from the calls for applications for the individual cogeneration bonus to the auction-based support system, which currently serves as the most important mechanism—after operational capacity—for high-efficiency cogeneration.

- From the perspective of timely project implementation aimed at replacing phased out coal-fired units, it is crucial to be able to obtain a decision on environmental conditions within a reasonable and predictable timeframe; therefore, it is reasonable to maintain the current wording of the provisions allowing the decision on environmental conditions to be immediately enforceable and to implement investment decisions until the decision on environmental conditions becomes final. A departure from current legislative solutions governing environmental procedures may hinder the achievement of national and EU climate and energy goals, increase investment risk, and result in the loss of funds under the CHP support mechanism due to failure to meet the project execution date.

- The **heat tariff** system should be adapted to new technology and fuel mixes, including the use of municipal solid waste / RDF in waste-to-energy plants (WTE) and biomethane used on its own or blended with natural gas in cogeneration units.

- It is essential to safeguard the role of cogeneration units in the **new capacity market** and to continue the support system for high-efficiency cogeneration after 2048. As a local source of available electricity and heat, cogeneration should be taken into account in mechanisms designed to ensure capacity adequacy, particularly during periods of low RES generation and high demand.

- At the national level, it is also reasonable to introduce additional incentives for small-scale cogeneration units (with a capacity of less than 1 MW) and for investments using **renewable gaseous fuels**, in particular biomethane, e.g., involving a dedicated reference price that takes into account the higher cost of this fuel.

- At the EU level, it is crucial to **properly align the pathway for the increase in minimum share of heat from renewable energy sources or waste heat with the criteria for an efficient district heating system from 2035 onwards**. The current sharp increase in the requirement from **5% to 35%** may be particularly challenging for large urban district heating systems; therefore, it is recommended to limit this threshold to a maximum **of 15%** in a mixed criterion that includes high-efficiency cogeneration.

- The EU Taxonomy regulations should **associate the requirement for the "fuel transition" of gas-fired units by 2035 with the actual availability of decarbonized fuels and infrastructure.** The lack of availability of biomethane, renewable hydrogen, or synthetic fuels, as well as the lack of adequate infrastructure, should not automatically result in a project losing its compliance with the EU Taxonomy if the operator demonstrates that it has acted with due diligence. The objectives of the EU Taxonomy should be defined in such a way that they are realistic to achieve.

- It is also recommended **that the emissions threshold for high-efficiency cogeneration in the EU Taxonomy be maintained at 270 g CO_2/kWh throughout the transformation period.** The stability of this criterion is crucial for investment predictability, project bankability, and avoiding a situation in which newly constructed units would have to be cost-intensively retrofitted to meet more stringent standards before reaching the assumed payback period.

- Under the works on **amending the General Block Exemption Regulation (GBER)**, which will take effect in 2027, it is reasonable to align state aid rules with the actual scale of investments in the transformation of district heating systems, renewable energy, and high-efficiency cogeneration. This includes **raising the notification thresholds for projects covered by Articles 58 and 64 of the GBER to 150 million EUR, increasing the basic aid intensity to 45% of eligible costs, raising the threshold for small projects to 5 million EUR, and introducing an additional bonus of +15 percentage points for investments in district heating systems in accordance with the climate neutrality plans** referred to in Article 10b(4) of the EU ETS Directive. These changes are necessary to ensure that the state aid framework reflects the current costs and scale of retrofitting projects and enables the timely implementation of investments necessary for decarbonization and maintaining the security of heat supply.

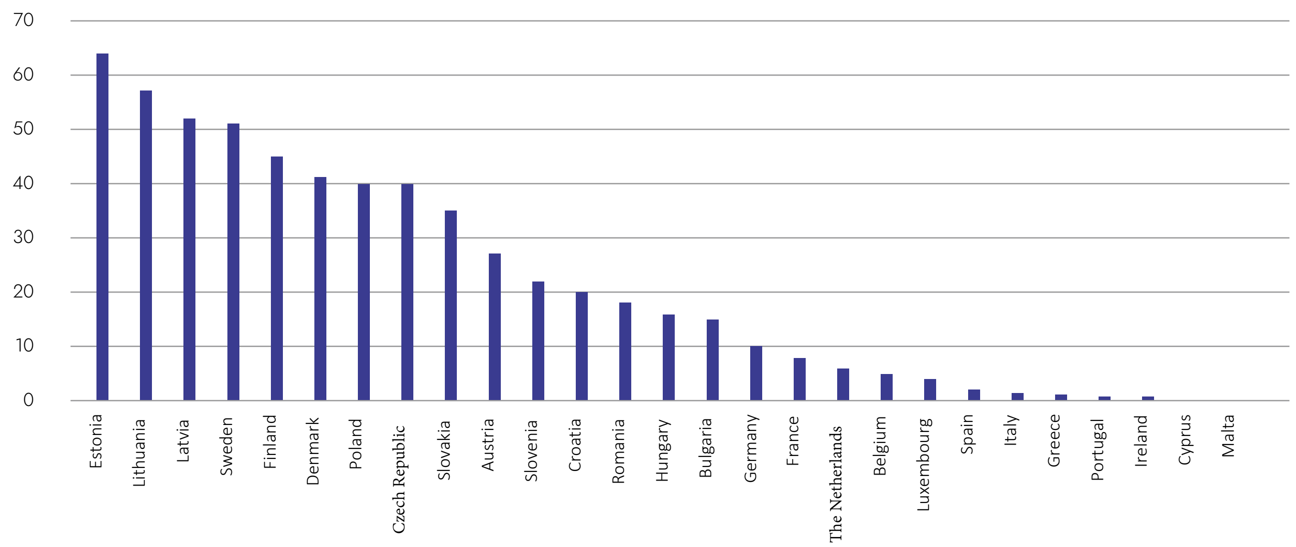
1. Cogen eration in District Heating and Power Systems in Poland and the EU

1.1. District Heating in Poland – Scale and Significance

District heating is one of the pillars of the national energy sector and plays a much greater role in Poland than in most European Union countries. Nearly 45% of households in Poland use district heating, which accounts for about half of the country's population. In urban areas, this share exceeds 60%, making district heating the dominant source of heating.

This places Poland among the European leaders in terms of the scope and significance of this market segment. The scale of district heating, its concentration in cities, and its strong ties to local infrastructure make this sector crucial for energy security and the achievement of energy transition goals in the heating sector.

Chart 1: Share of district heating in household heating in the EU (%, 2023), *source: own study based on Eurostat.*



According to the latest report by the President of the Energy Regulatory Office, as of the end of 2024, 398 companies were operating under licenses in Poland's heat engineering sector, holding a total of 815 licenses for the generation, transmission, distribution, and trading of heat. In the long term, this sector has undergone a significant structural transition. Since the early 2000s, there has been a decline in the number of companies and in employment, as well as a reduction in installed capacity and contracted capacity. These trends are a consequence of improved energy efficiency in buildings, thermal modernization of the housing stock, and climate change, all of which have led to a decrease in heat demand. The expansion of the distribution infrastructure was accompanied by a steady decline in heat demand and sales volume. Between 2002 and 2024, heat sales fell by approximately 31%, and in 2024 alone, a further year-over-year decline of 3.5% was recorded, despite an increase in the length of district heating networks by nearly 33% during the same period. This was also accompanied by a sustained decline in the installed capacity of heat sources (by approximately 27%) and in contracted capacity. The structural reduction in heat demand stems from improvements in the energy efficiency of buildings, demographic changes, and increasingly milder heating seasons. Under these conditions, the district heating sector has entered a phase in which infrastructure development does not translate into increased demand, and the key challenge is maintaining economic competitiveness and security of supply amid declining sales volumes.

1.2. Cogeneration in Polish district heating systems and the National Power System

Cogeneration is the primary method of district heat generation in Poland. In 2024, approximately 64% of district heating came from cogeneration units, confirming that cogeneration is a true pillar of the country's district heating systems.

At the same time, cogeneration units play a significant role in the National Power System. Electricity production in cogeneration accounts for approximately 14% of the country's total electricity production, remaining at a relatively stable level despite the rapid development of renewable energy sources. The stability of this share indicates that cogeneration remains an important source of dispatchable and regulating power, particularly in urban areas.

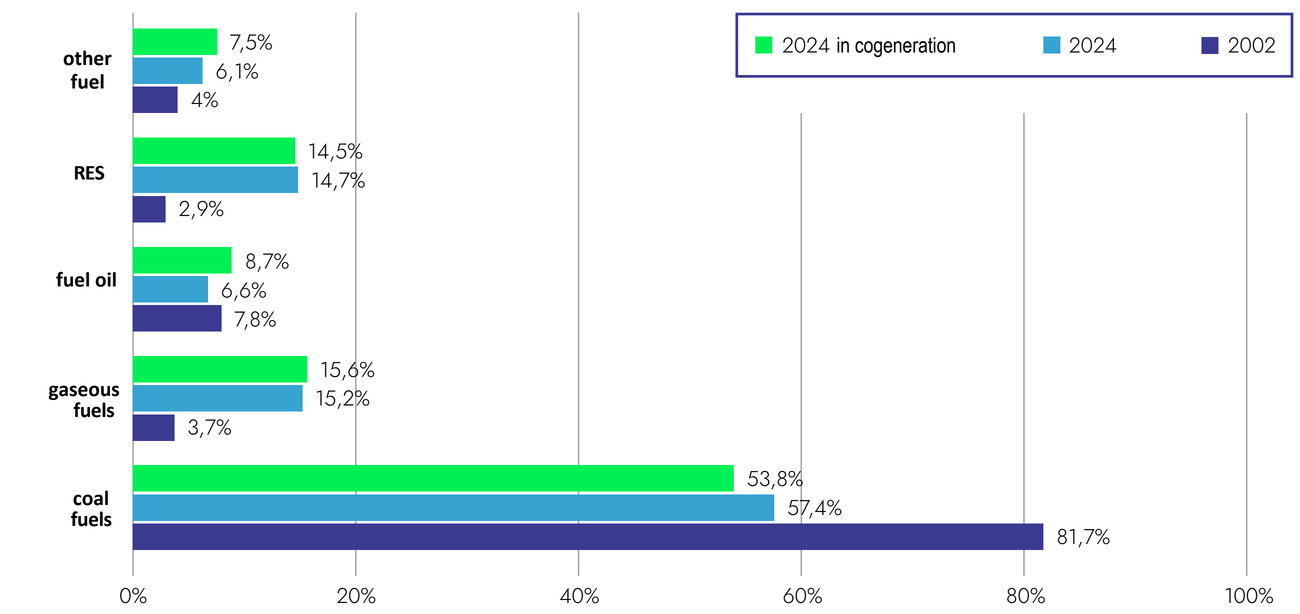
Another significant aspect is the impact of cogeneration on the costs incurred by consumers. In 2024, the average price of heat generated through cogeneration (99.66 PLN/GJ) was lower than that from non-cogeneration sources (116.63 PLN/GJ), confirming that cogeneration not only supports energy efficiency but also stabilizes heat prices in district heating systems.

1.3. Fuel Mix for Cogeneration and Transformation Challenges

The structure of cogeneration fuels in Poland is undergoing a gradual but uneven transition. In 2024 (according to Energy Regulatory Office's data, "Heat power engineering in numbers – 2024"), coal fuels remained the dominant source of energy, accounting for more than half of the fuels used in cogeneration. At the same time, their share has been steadily declining—over the past dozen or so years, this decline has exceeded 20 percentage points. At the same time, the importance of gaseous fuels is growing, as they have become the primary means of replacing decommissioned coal-fired units. Natural gas currently serves as a transition fuel, enabling a reduction in CO_2 emissions and increasing the operational flexibility of cogeneration plants, while ensuring the security of heat and electricity supplies.

The share of renewable energy sources in cogeneration remains at around 15%, with biomass accounting for the vast majority. Compared to some EU countries, the scale of RES integration into district heating systems in Poland remains limited, due to both resource constraints and the structure of historical investments.

Chart 2. Structure of fuels according to energy content, consumed for heat generation in 2002 and in 2024, and for heat production in cogeneration in 2024. *Source: Energy Regulatory Office, Heat power engineering in numbers – 2024, Warsaw 2025.*

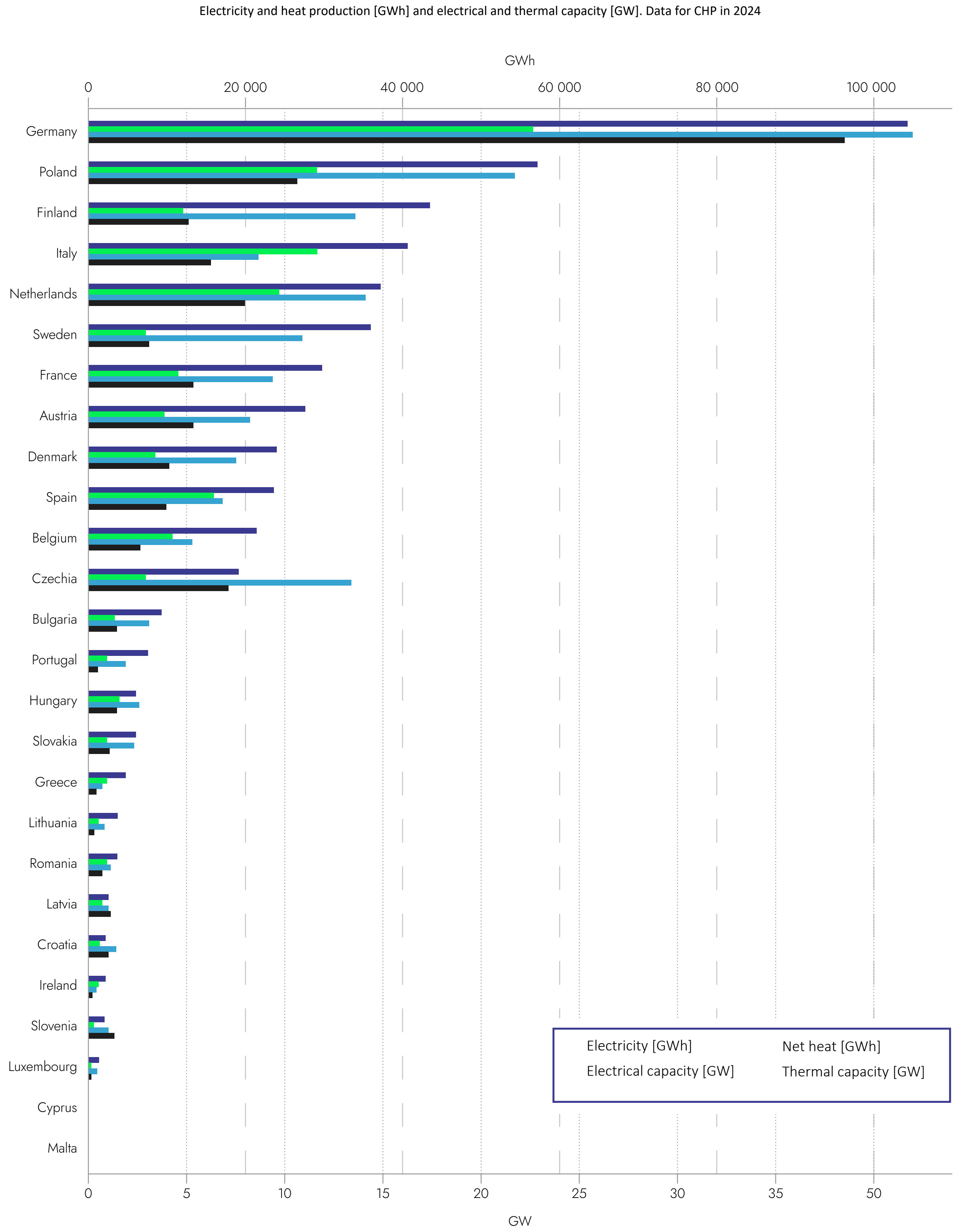


1.4. Poland in Comparison with the European Union – Scale and Significance of Cogeneration

Within the European Union, Poland is among the countries where cogeneration plays a significant role. Eurostat data for 2024, used in this report, indicate that cogeneration units in the EU produced a total of approximately 248.2 TWh of electricity and approximately 518.0 TWh of net heat. This corresponded to an electrical capacity of CHP units of approximately 109.7 GWe and a net thermal capacity of approximately 178.6 GWt (excluding Estonia, for which—as of the date of this report—no data for 2024 was available from Eurostat). These data show that cogeneration potential in the EU is not distributed evenly but is concentrated in a relatively small group of member states. Depending on the parameter analyzed – electricity production, net heat production, electrical capacity, or thermal capacity – the largest cogeneration markets include primarily Germany, Poland, and a group of countries such as the Netherlands, Italy, Finland, Denmark, Sweden, the Czech Republic, France, and Austria.

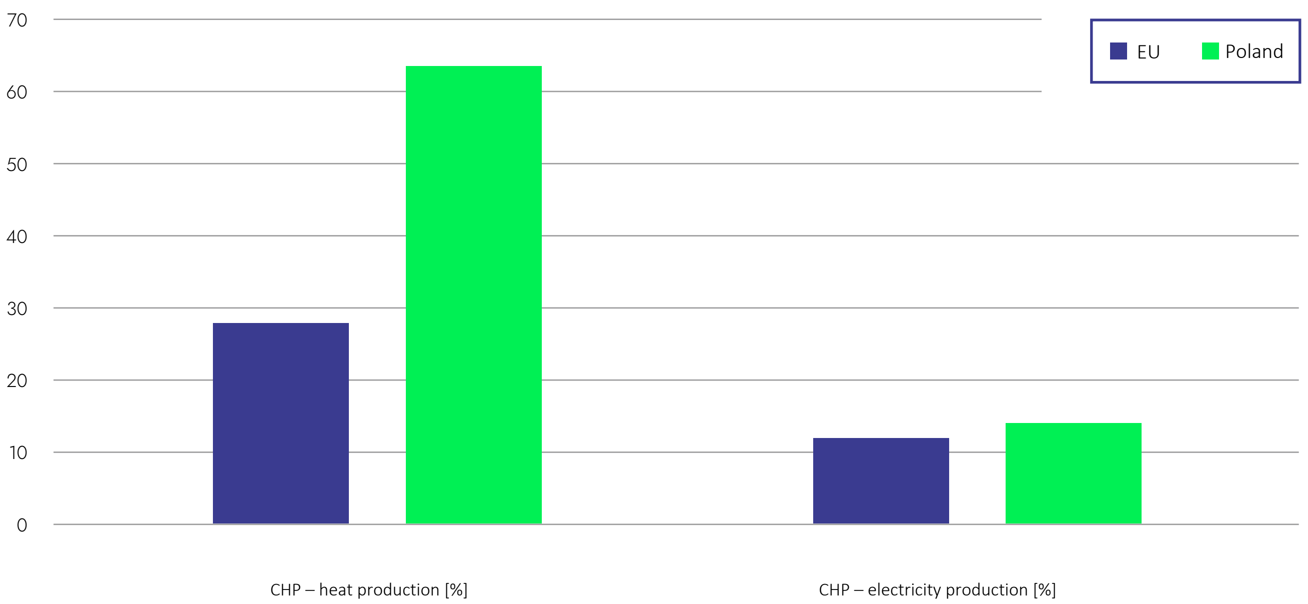
According to Eurostat data for 2024, Germany has the largest scale of cogeneration capacity in the EU, with approximately 38.5 GWe of CHP electrical capacity and approximately 42.0 GWt of CHP thermal capacity. Poland, with an electrical capacity of approximately 10.6 GWe and a thermal capacity of approximately 21.7 GWt, is one of the EU's major cogeneration markets. This is also confirmed by production volumes: in 2024, CHP units in Poland produced approximately 29.2 TWh of electricity and approximately 57.3 TWh of net heat, while in Germany the figures were approximately 56.8 TWh and 104.4 TWh, respectively.

Chart 3: Cogeneration in the EU: installed capacity and heat and electricity production from CHP – own study based on Eurostat.



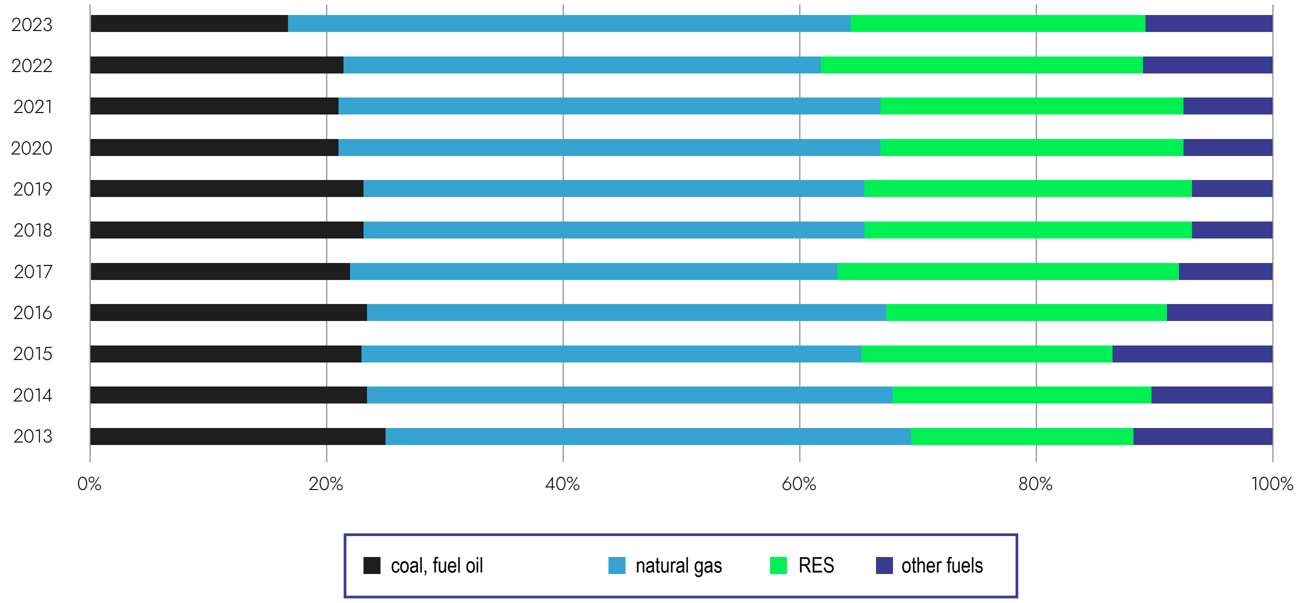
Compared to the rest of the EU, the scale of cogeneration use in Poland is particularly high in the heat sector. While data from COGEN Europe indicate that, on average, cogeneration accounts for approximately 28% of heat production and approximately 12% of electricity production in the EU, in Poland, according to data from the Energy Regulatory Office and the Energy Market Agency for 2024 – CHP accounts for approximately 64% of district heating and approximately 14% of the country's electricity production. This shows that in Poland, cogeneration plays a much more systemic role in district heating than the EU average – that is, it is one of the primary sources of power for district heating systems and, at the same time, a significant local source of electricity that supports the operation of the NPS. However, the differences among EU countries concern not only the scale of cogeneration use, but also the role that cogeneration plays in a given energy system. In Poland, the district heating model predominates, in which cogeneration units are directly linked to municipal district heating systems and ensure a steady supply of heat to consumers. In Germany, cogeneration is more diverse in nature – it is used in district heating, industry, and local energy sources. In Denmark and Finland, on the other hand, cogeneration is closely linked to district heating, but operates within a model that is more integrated with RES, biomass, waste, heat storage, and Power-to-Heat technologies. A different model can be seen in countries such as the Netherlands, Italy, and Spain, where a significant portion of cogeneration is linked to industry, local applications, or specific sectors of the economy, rather than to district heating to the same extent as in Poland. This means that a similar or significant scale of electricity production from cogeneration in some EU countries does not necessarily imply that cogeneration plays the same role in the district heating system. In Poland, any reduction or change in the CHP operating model has a direct impact on district heating systems, the local electricity balance, and the need to expand the power systems.

Chart 4: Comparison of the share of cogeneration in heat and electricity generation in the EU and Poland in 2024.
Source: own study based on Eurostat and "Heat power engineering in numbers – 2024," Energy Regulatory Office



A key factor distinguishing Poland from the rest of the EU is the structure of cogeneration fuels and the resulting starting point for the transition. At the EU level in 2023, natural gas was the dominant fuel in CHP (approx. 48%), with a relatively low share of coal fuels (approx. 17%) and a growing share of RES, reaching approx. 25%. In the Nordic countries, municipal waste-to-energy plants and biomass play a significant role in cogeneration. The high share of waste and biomass in Denmark, Sweden, and Finland – which are characterized by lower emissions compared to fossil-fuel-based cogeneration units – ensures stable, year-round operation of CHP units, largely independent of seasonal fluctuations in heat demand. As a result, these units achieve high annual operating hours, which naturally translates into a high share of CHP in electricity production from thermal units and into their strong role in balancing the power system.

Chart 5: Structure of fuels in cogeneration units in the EU. *Source: Cogen Europe, based on Eurostat data.*



In Poland, the situation is fundamentally different. A significant portion of cogeneration capacity still relies on coal-fired units, which were designed under conditions of historically high and stable demand for heat and electricity. In many cases, these units are oversized relative to current market needs and are characterized by high minimum technical requirements, which limits their operational flexibility. At the same time, the rapid growth of RES means that wind and solar power are increasingly becoming part of the base load of the power system, reducing the annual operating time of thermal units. As a result, despite the high installed capacity, annual electricity production from CHP in Poland is lower than would be expected based on the technical potential of the generating units, although at the same time – in absolute terms – Poland generates more electricity from cogeneration than the EU average. The limitation, therefore, is not the size of the sector, but rather the conditions under which it operates: the seasonal nature of heat demand, the fuel and technical structure, and increasing regulatory requirements.

Another key factor shaping the future model of CHP operations is the EPS emissions requirement of 270 g CO_2/kWh of energy produced through cogeneration (including thermal/cooling energy, electricity, and mechanical energy), as set forth in Annex III of Directive (EU) 2023/1791 of the European Parliament and of the Council of 13 September 2023 on energy efficiency and amending Regulation (EU) 2023/955 (EED), as well as Commission Delegated Regulation (EU) 2021/2139 of 4 June 2021 supplementing Regulation (EU) 2020/852 by establishing the technical screening criteria for determining the conditions under which an economic activity qualifies as contributing substantially to climate change mitigation or climate change adaptation (EU Taxonomy). In practice, starting in 2028, this criterion will limit the ability of CHP units to operate in non-cogeneration mode, thereby reinforcing an operating model focused on district heating and accelerating the need for technological modernization toward natural gas, RES, and low- and zero-emission fuels.

Table 1. Share of cogeneration in heat production and characteristics of the role of CHP in selected EU countries.
Source: own study based on Eurostat and DHC Market Outlook 2025, Euroheat&Power

Region/country	Share of cogeneration in heat production (%)	System characteristics
Poland	**64%**	Cogeneration as the foundation of district heating systems, supporting the NPS
EU 27 (average)	**28%**	Cogeneration primarily serves a supplementary role and is an important source of energy for industry
Denmark	>70%	Strong integration of CHP with Power-to-Heat (RES) and heat storage systems
Finland	>60%	High share of CHP in district heating
Germany	approx. 40%	The largest CHP market in the EU in terms of capacity and production, but one that is more decentralized and diverse than the Polish model, which is based on district heating systems.
Spain	<20%	The largest CHP market in the EU in terms of capacity and production, but one that is more decentralized and diverse than the Polish model, which is based on district heating systems.

In the Polish context, cogeneration primarily serves as critical infrastructure for district heating systems and for balancing the NPS at the local level. Its future value will be determined not by the volume of electricity generated, but by operational flexibility, the ability to regulate output, integration with heat storage systems and P2H technologies, and the gradual transition to low- and zero-emission fuels. In this sense, Poland – despite having a different starting point than most EU countries – has one of the greatest potentials for the further evolution of cogeneration toward a system-wide and flexible model capable of meeting the challenges of the transition after 2030 and 2035.

2. Cogeneration as a Support for the National Power System

2.1. Cogeneration within the National Power System's structure

Structure of the National Power System – generation sources and demand centers

The structure of Poland's National Power System is characterized by a persistent disparity between the location of a significant portion of its generating capacity and the areas with the highest demand for electricity. This situation is the result of historical investment decisions, resource and environmental factors, and, to an increasing extent, the conditions for the development of renewable energy sources.

The largest system power plants have been located primarily outside metropolitan areas, often at a considerable distance from major centers of demand. This applies to both coal-fired units (including Bełchatów, Turów, Kozienice, Opole), which were located near resources – such as lignite mines – as well as planned new nuclear power plants, whose location in the north of the country is dictated by access to cooling infrastructure. The development of offshore wind energy – concentrated in northern Poland – and a significant portion of onshore wind farms, located outside urban areas, follows a similar logic.

As a result of the energy transition, this structure is also being supplemented by a growing number of gas-fired power plants, which serve as dispatchable and regulating capacity. In Poland, new gas-fired units are predominantly being built at the sites of existing or decommissioned coal-fired powerplants, utilizing available connections to the transmission network and system infrastructure. At the same time, compared to conventional coal-fired units, gas-fired power plants offer significantly greater operational flexibility, including shorter startup times and the ability to quickly adjust load, which allows them to be used effectively to balance the fluctuating output of renewable energy sources. One example is the Dolna Odra combined cycle power plant in Gryfino, which – built on the site of a former coal-fired power plant – strengthens the regional power balance in the northwestern part of the NPS and reduces the need to transmit energy from more distant generation sources. A key factor shaping the current and future spatial structure of the NPS is the rapid development of renewable energy sources. According to PSE's Transmission Network Development Plan for the years 2025–2034, over the next decade, large volumes of new RES capacity are expected to be connected to the network, including, in particular, approximately 18 GW of offshore wind farms, approximately 45 GW of photovoltaic sources, and over 19 GW of onshore wind farms[1]. This development will be largely geographically concentrated – that is, offshore wind farms in the north of the country, a significant portion of onshore wind power outside urban areas, and distributed photovoltaic power, mainly in distribution networks. In recent years, the rapid growth in renewable energy capacity – particularly solar power – has significantly changed the nature of the NPS's operations. The expansion of PV, concentrated largely in low- and medium-voltage networks and in areas with relatively low local demand, has led to the emergence of new system challenges, including increased generation variability, the occurrence of local power surpluses, and growing difficulties in balancing the system on a daily and seasonal basis. These phenomena are having an increasingly significant impact on the operation of transmission and distribution networks, leading to an increase in unplanned flows and node loads, particularly between generation areas and demand centers.

In the long term, the development of RES, given an unchanged spatial structure of electricity consumption, will lead to a further increase in the importance of system flexibility, including the need for sources capable of balancing variable generation and mitigating the effects of spatial asymmetry. In this context, the specific challenges associated with integrating the growing share of RES, including solar and wind power, into the NPS – as well as the role of the heating sector, including cogeneration, in stabilizing system operation – were discussed in detail in the 2025 PTEC report titled "Integration of the heating and power sectors – or how to leverage the transition of district heating to ensure the security of heat supply and stabilize the operation of the power system".

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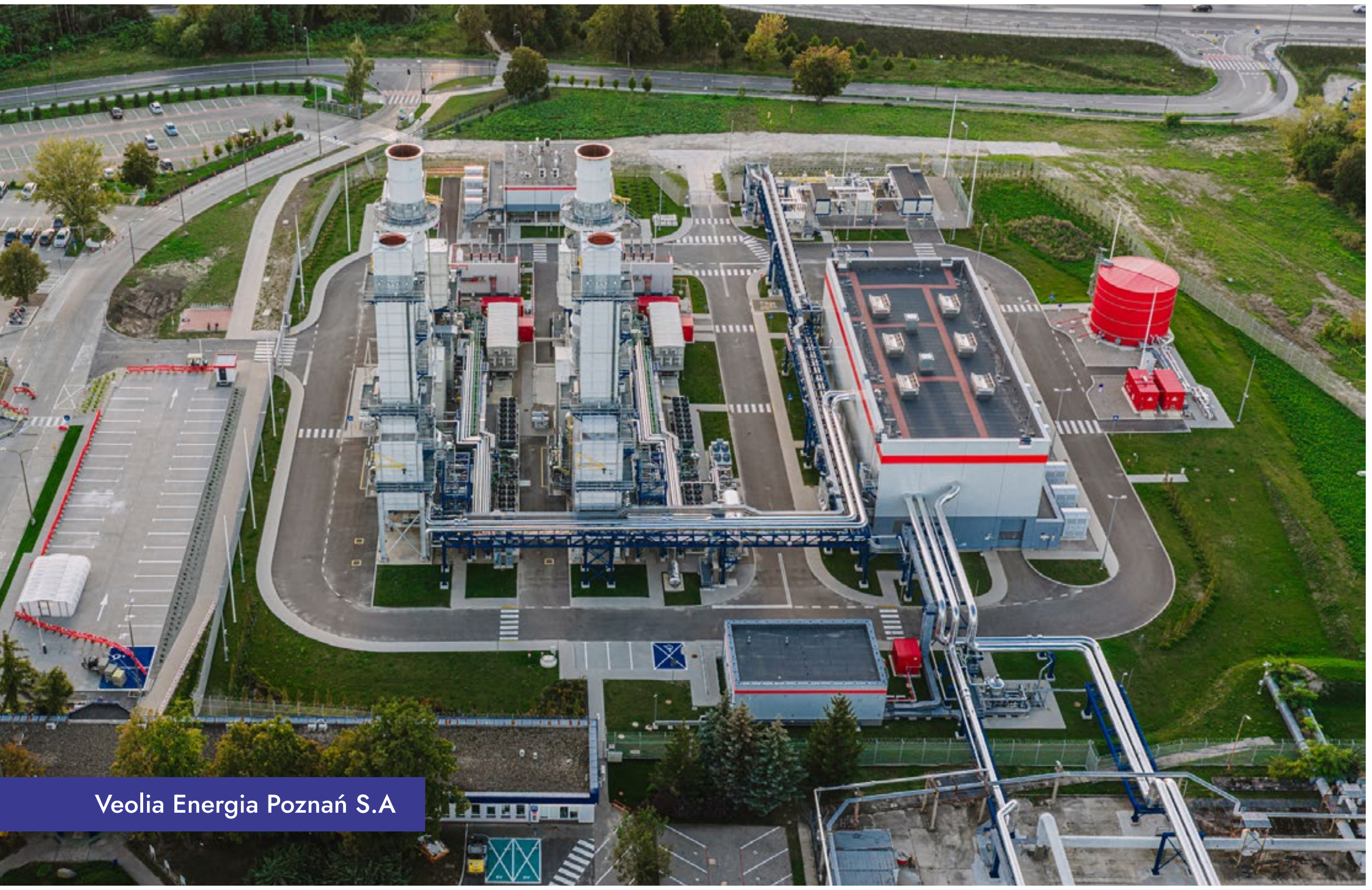
1. Polskie Sieci Elektroenergetyczne, Plan rozwoju w zakresie zaspokojenia obecnego i przyszłego zapotrzebowania na energię elektryczną na lata 2025–2034 [Development Plan for meeting the current and future electricity demand for 2025-2034], approved on December 20, 2024



Spatial concentration of electricity demand

Electricity demand in Poland is highly concentrated both geographically and by sector. The highest system loads occur:

- in large metropolitan areas, where demand from the residential, service, and transportation sectors accumulates,
- in regions with a high concentration of energy-intensive industries.

Among the most important areas of demand is, in particular, the Warsaw metropolitan area, which is the largest single node of electricity demand in the country. High and relatively stable loads are also generated in the Upper Silesian-Dąbrowa Basin Metropolis, where demand stems both from intensive urbanization and from the presence of industry, rail infrastructure, and public transportation.

Lower Silesia also plays a significant role in the structure of demand, as it is home to metallurgical, chemical, and electrical machinery industries, as well as the regions of Greater Poland and the Łódź Voivodeship, where the manufacturing industry and logistics infrastructure are growing in importance. In the Pomerania region, particularly in the Tricity area, the demand for electricity is driven by port operations, the shipbuilding industry, the chemical sector, and densely populated urban areas With the ongoing electrification of heating, the development of air conditioning and cooling, and the gradual increase in demand resulting from electromobility, demand is increasingly concentrated in urban areas, which translates into higher loads on the 110 kV network.

The role of cogeneration combined heat and power plants in the spatial structure of the NPS

Given the above structure of generation and demand, cogeneration units play a special role; the vast majority of them are located:

- within the boundaries of large cities or on their immediate outskirts,
- in the immediate vicinity of the largest centers of demand,
- at key nodes of distribution and transmission networks.

Commercial combined heat and power plants in Warsaw, Kraków, Łódź, Wrocław, the Tricity, and the Upper Silesian-Dąbrowa Basin Metropolis generally operate in areas where the demand for electricity and district heating is highest, and at the same time most sensitive to local network constraints. From the NPS perspective, this means that the network of combined heat and power plants forms a dense, urban structure of generation sources that:

- supplies the areas with the heaviest load on the 110
- reduces the need to transmit electricity from distant system power plants and renewable sources (located outside cities or in Pomerania)
- reduces the load on 400/2200 kV/110 kV nodes,
- improves the local power balance in areas with the highest demand.

A spatial analysis of the distribution of power generation sources and the concentration of electricity demand indicates that cogeneration units in district heating systems play the role of significant local system units within the NPS. Their location in large metropolitan areas and regions with the highest network loads means that they naturally complete the system’s structure, reducing the distance between energy generation and consumption. Given the growing share of RES, the concentration of new generation capacity outside demand centers, and the ongoing electrification of consumers, cogeneration supports the NPS by reducing peak loads and improving the local power balance in areas most vulnerable in terms of security of supply.

The synergy between the heating and power sectors is therefore manifested not in maximizing the volume of electricity produced from CHP, but in their ability to stabilize system operation, optimize network costs, and increase the resilience of the NPS during the energy transition.

2.2. Effects of cogeneration location on the operation of power systems

The effects of the spatial distribution of cogeneration units described in the previous subsection translate into specific technical and economic outcomes in the operation of power systems. Producing electricity close to end users shortens the energy transmission path, reduces the load on certain network components, and may limit the scale of necessary investments by transmission and distribution system operators.

Reducing technical (network) losses through local generation

One of the key arguments highlighting the importance of local combined heat and power plants is the reduction of technical losses in power networks. These losses increase with the length of the power transmission line and the level of power being transmitted. During peak demand hours, increased flows through transmission networks result in additional network losses, which not only raise energy transmission costs but also increase the risk of outages.

Producing electricity close to where it is consumed makes it possible to:

- shorten the distance over which electricity is transmitted,
- reduce current flows in extra high voltage lines,
- reduce resistive losses in transmission and distribution networks,
- limit the proportion of reactive power by shortening the distance between the source and the consumers.

In practice, this means that the same amount of useful energy can be delivered to consumers while reducing the load on the grid infrastructure. At the national system level, this translates into measurable savings in primary energy, reduced costs for system operators, reduced greenhouse gas emissions, and improved energy efficiency across the entire sector.

Reduced flows in transmission networks

Local combined heat and power plants play a key role in reducing power flows at the transmission network level. In the traditional model of centralized power generation, a significant portion of energy must be transported over long distances—from grid-connected power plants to urban areas and industrial centers.

The opening of cogeneration plants near large concentrations of consumers allows to:

- meet part of the demand locally,
- reduce the load on transmission network nodes, and
- limit the need for inter-system transfers,
- combined heat and power plants are often connected to the local medium-voltage grid, as a result, part of the energy is transmitted via MV grids, which not only shortens the distance from the source to the consumer but also strengthens the local architecture of the grid systems, thereby contributing to improved operational reliability of the grid.

Consequently, the importance of distributed cogeneration systems is growing. This is particularly important given the growing instability of renewable energy generation, as the transmission network increasingly serves as a "buffer" for large volumes of energy that, during periods of excess renewable energy production, are not consumed locally in the vicinity of those sources. The local combined heat and power plant then acts as a balancing source, reducing the amplitude of flows and improving the operational reliability of the National Power System. In the reference model, the district heating system can limit the operation of cogeneration units during periods of excess electricity from renewable energy sources, and meet heat demand using Power-to-Heat systems and heat storage facilities, while during periods of shortage, can use cogeneration to make up for shortfalls in electricity and heat production.

Load shedding on grid nodes during peak hours

Peak electricity demand periods pose the greatest challenge for both power generation and grid infrastructure. Thanks to their flexibility and high availability, local combined heat and power plants are particularly well-suited to operate during these periods. Their presence in the system allows to:

- reduce the load on transformers and lines at HV/MV and MV/LV nodes,
- reduce the risk of infrastructure overloads and
- improve the voltage and load safety margins.

In practice, a combined heat and power plant operating near a grid node acts as a local "system fuse," capable of taking over part of the load when there is a risk of overload. In peak load conditions and in emergency situations, local cogeneration enhances grid stiffness by providing short-circuit power from the generator.

Postponement and optimization of grid expansion

One of the most important – and often underestimated – benefits of local combined heat and power plants is the ability to postpone costly grid investments. The expansion of transmission and distribution networks – including new lines, substations, and transformers – involves high capital expenditures, lengthy administrative procedures, and growing public resistance.

For system operators, this means more flexible and efficient planning of grid expansion and improved reliability of energy supply; for consumers, it means lower utility rates over the long term.

2.3. Replacing power from coal-fired plants – the investment gap and the role of cogeneration units

According to data from ARE reports, the installed electric capacity in cogeneration units within the National Power System (NPS) between 2018 and 2024 remained stable at approximately 10 GWe, the vast majority of which (on average, about 75%) was supplied by commercial combined heat and power plants. In 2024, as much as 4.9 GWe of the 7.7 GWe of installed capacity came from coal-fired units, 2.6 GWe from gas-fired units, and 0.2 GWe from biomass and other fuels. In 2024, as much as 53% of electricity was generated from coal, 42% from natural gas, 4% from biomass, and 1% from other fuels.

Chart 7: Installed capacity [GWe] in commercial combined heat and power plants from 2018 to 2024.
Source: own study based on ARE data

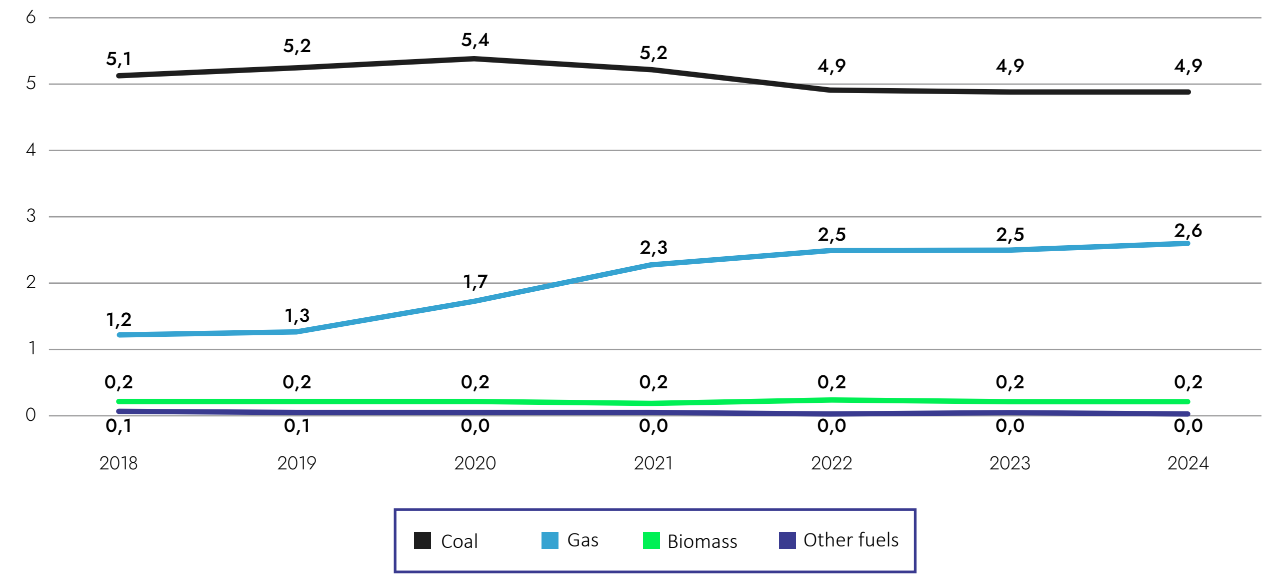
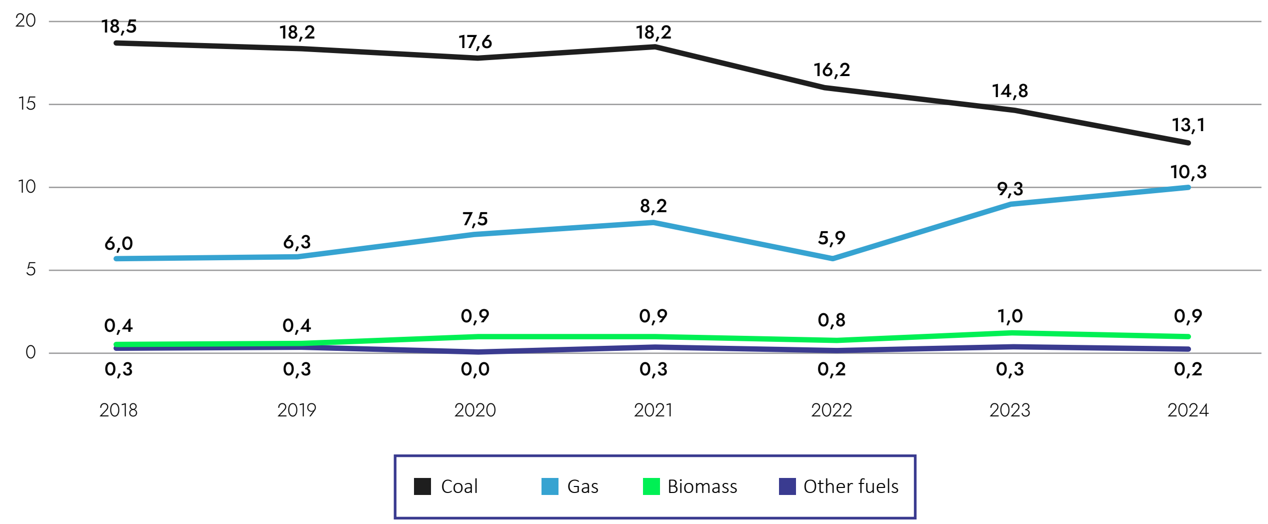


Chart 8: Electricity generation [GWh] at commercial combined heat and power plants from 2018 to 2024.
Source: own study based on ARE data



Observing the changes taking place in the market, there is a noticeable gradual shift away from cogeneration in coal-fired power plants, as evidenced primarily by a nearly 30% decline in production over the past 5 years, as well as by the gradual decommissioning of installed capacity. Given the gradual phase-out of coal-fired cogeneration units, a key issue is what changes will occur in the electricity market following their complete phase-out, which is inevitable. Most owners of coal-fired combined heat and power plants have already committed to phasing them out by 2030–2035 at the latest. The installed capacity of 4.9 GWe (4.4 GWe available capacity) in coal-fired cogeneration units consists primarily of units with a capacity exceeding 200 MWe (57%), 100–199 MWe (24%), and 50–99 MWe (10%). Given the ongoing transition of the heat markets and the requirements set forth in the new definition of high-efficiency cogeneration (emission limit – EPS 270 gCO_2/kWh for fossil-fuel-fired units), it is anticipated that it will not be possible to fully replace this capacity with gas-fired cogeneration technology. In addition, the introduction, starting in 2035, of a requirement in the criteria for efficient district heating systems for a minimum share of heat from renewable energy sources or waste heat at the level of 35% – in a mixed renewable energy/waste heat/high-efficiency cogeneration – will significantly affect the operation of cogeneration units, which will result in a reduction in their operation within the system. The lack of such a significant amount of electric capacity will necessitate the construction of new dispatchable capacity at gas-fired power plants, which will operate on an as-needed basis during peak heat demand hours, when electricity from renewable energy sources is not available in the National Power System.

Some of this capacity can be replaced by gas-fired cogeneration, particularly where there is a demand for district heating and a need for local support for the National Power System. However, the intended role of the new cogeneration units will depend on their integration with heat storage systems and Power-to-Heat technologies, as discussed in the subsection on Flexibility and system services.

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2.4.Cogeneration support system

The support system for high-efficiency cogeneration currently in place in Poland remains a key element of the CHP investment pathway. This mechanism is based on operational support granted through auctions or calls for proposals, which varies depending on the technology, unit capacity, and fuel type, and is intended to compensate for the cost gap between electricity generation in cogeneration and distributed generation. This mechanism was implemented pursuant to the Act of December 14, 2018, on the promotion of electricity from high-efficiency cogeneration (Journal of Laws of 2025, Item 602).

The support system was notified to the European Commission and approved by it as a measure that complies with state aid rules, which confirms its alignment with the EU's objectives regarding energy efficiency, security of supply, and decarbonization. From the investors' perspective, this is significant because it reduces regulatory risk and increases the predictability of the economic conditions for implementation of cogeneration projects. This system covers existing, retrofitted, and new facilities, with mechanisms dedicated to new and significantly retrofitted facilities playing a key role in the investment pathway. Support for new or significantly retrofitted CHP units is granted in the form of a cogeneration bonus through an auction (for units with a capacity of 1 MW to 50 MW) or through a call for applications for an individual cogeneration bonus (for units with a capacity of at least 50 MW). The maximum period of operational support is 15 years from the date of the first generation and sale of electricity, but no later than December 31, 2048, which sets the minimum operational horizon for new units in the power system even after 2035.

An analysis of previous decisions indicates limited interest in the individual cogeneration bonus mechanism. This support was awarded only twice—in the call for proposals concluded in 2021. Since then, despite nine subsequent calls for proposals through April 2026, not a single proposal has been submitted. It is worth noting that in the most recent call for proposals, held in April 2026, a budget of over PLN 14.9 billion remained available for allocation. The situation is different for the cogeneration bonus awarded through an auction, which has attracted significantly more interest from investors. According to announcements by the President of the Energy Regulatory Office, 17 investment projects received support following the results of the auctions announced in 2025. The following is an overview of the auctions held in 2025.

Table 2. Summary of the 2025 cogeneration auction results – *own study based on data from the Energy Regulatory Office.*

		Auction parameters		Winning bids		
Designation of the auction	Auction Date	Volume [MWh]	Budget [PLN]	Number	Volume [MWh]	Value [PLN]
ACHP/1/2025	24-26.03	28 330 720	3 021 877 020	6	5 703 384	1 373 814 018
ACHP/2/2025	10-12.06	22 627 336	1 648 063 002	8	6 133 080	1 495 900 620
ACHP/3/2025	22-24.09	16 494 256	152 162 382	3	823 610	146 500 152
ACHP/4/2025	15-17.12	15 670 000	5 662 000	-	-	-

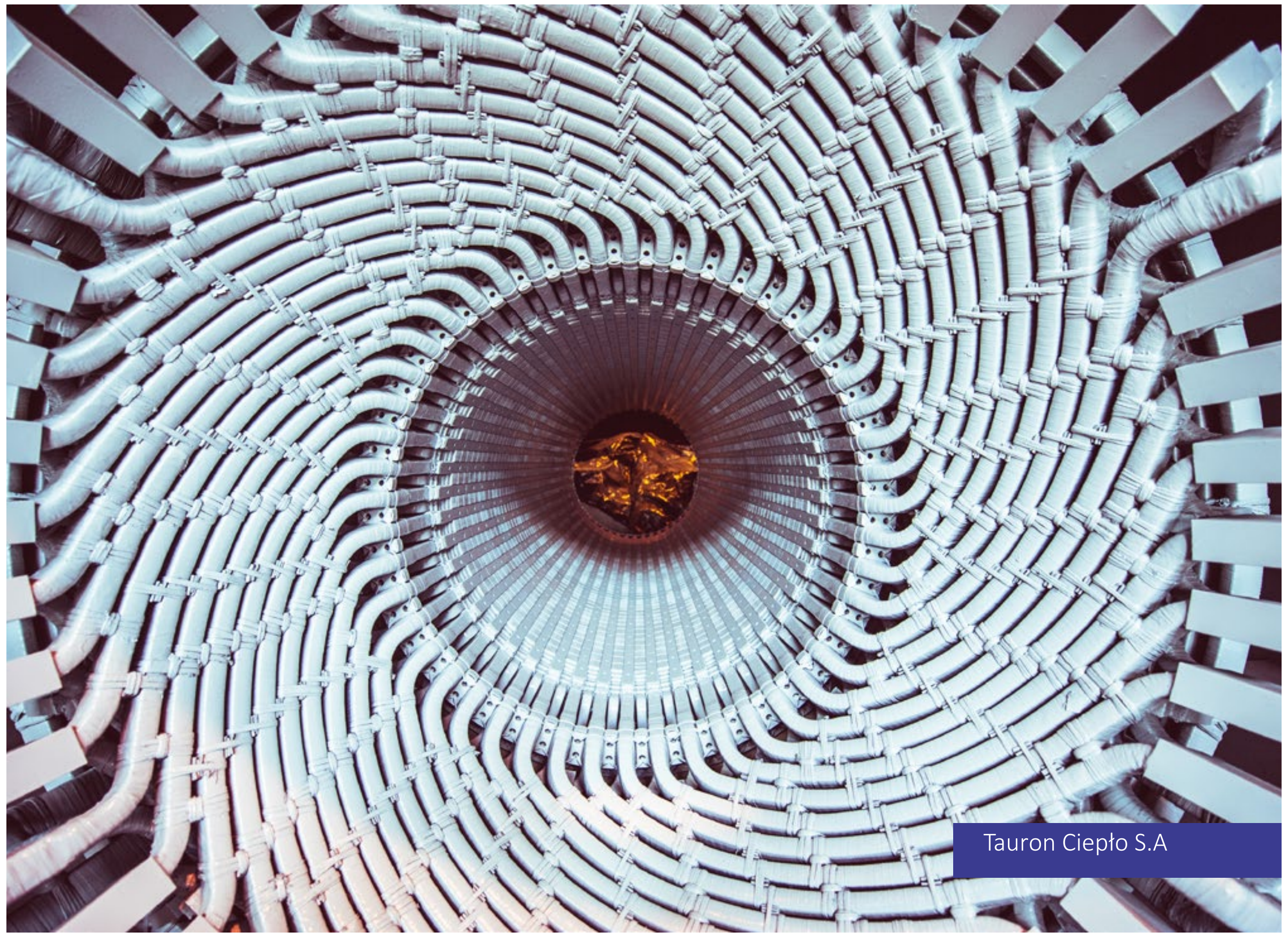
In 2025, nearly 95% of the available budget for support in the form of a cogeneration bonus had already been utilized by the end of the second auction. Due to the low auction budget remaining for the second half of 2025, the third auction attracted significantly less interest, while the fourth auction was not concluded. In total, in 2025, the auction budget was allocated at a level of approximately 99.8% of the total support available for that year in the form of cogeneration bonuses. In 2026, the President of the Energy Regulatory Office exercised for the first time the statutory option to hold more than one auction per quarter, planning a total of five auctions for the year. At the same time, in accordance with the Regulation of the Minister of Energy on the maximum quantity and value of electricity from high-efficiency cogeneration eligible for support and the unit amounts of the guaranteed bonus in 2026, the amount of funds allocated for the cogeneration bonus in 2026 is PLN 8.5 billion, which is significantly higher than in previous years. The favorable auction terms for 2026 encourage generators to apply for the bonus, which is reflected in the level of interest in participating in the auctions. As part of the first auction held in 2026, which took place from February 6 to 10, 2026, the cogeneration bonus was extended to 20 additional cogeneration units. The second auction, held from April 14 to 16, 2026, attracted a record number of bidders. Up to 15 generators, who submitted a total of 22 winning bids, will receive nearly PLN 4.4 billion in funding. The experiences presented regarding the operation of the support system for high-efficiency cogeneration show that the cogeneration bonus mechanism — implemented through an auction mechanism – not only effectively stimulates investment decisions in the short term but also structurally shapes the long-term presence of CHP units in the national power and district heating systems. The maximum 15-year period of operational support, combined with the statutory term of the system's validity through December 31, 2048, means that new and significantly retrofitted cogeneration units, commissioned in the second half of this decade, will operate within the system at least until the mid-2040s. Thus, the support system not only initiates investments, but also "anchors" the effects of these decisions over the long term, ensuring the continuity of available generation capacity, the stability of district heating supplies, and the maintenance of high-efficiency regulating sources in the power sector even after 2035.

2.5. Flexibility and system services: the role of cogeneration today and after 2035

The previous subsections have shown that the location of cogeneration facilities is important for grid operation and for mitigating the effects of spatial asymmetry between generation sources and demand. Another aspect of this role is the operational flexibility of cogeneration units, particularly as a share of renewable energy sources increases. In this context, the ability of combined heat and power plants to integrate with heat storage facilities and Power-to-Heat technologies, as well as to respond to signals from the National Power System and the energy market, becomes crucial. This section focuses on the role of CHP as a flexibility resource today and beyond 2035.

Integration of cogeneration with renewable energy sources – combined heat and power plants as flexible energy hubs

The growing share of renewable energy sources in the electricity mix is increasing the demand for resources capable of offsetting the variability in energy generation caused by weather conditions. In this model, local combined heat and power plants can serve to integrate the power and district heating systems, provided that they are not treated as individual, rigidly operating heat sources, but rather as multi-technology systems combining cogeneration units, as well as flexible gas engines, heat storage systems, Power-to-Heat technologies – such as electrode boilers and heat pumps – and demand management systems. The importance of combined heat and power plants in a system with a high share of renewable energy sources stems from their ability of two-way response to the situation in the National Power System. During periods of high wind or solar power generation, the district heating system can limit the operation of cogeneration units, increase electricity consumption by Power-to-Heat systems, and



Tauron Ciepło S.A

and store heat for later use. Tauron Ciepło S.A. During periods of low renewable generation, cogeneration units can increase electricity production, thereby supporting the power balance and reducing the need to activate less efficient reserve sources. The particular importance of this model becomes apparent in situations where renewable energy generation is limited, especially during periods of low wind, low sunlight, or high winter demand. Under these conditions, the combined heat and power plant can simultaneously generate electricity and heat, supporting the power balance in the National Power System and ensuring a continuous supply of heat to municipal customers. Cogeneration therefore serves as an energy security resource at the interface between two systems: the power system and the district heating system. In this context, medium-capacity gas-fired units – that is, those with a capacity ranging from a few to everal dozen MW - take on particular importance, as they can serve as a complement to larger combined-cycle power plants. Compared to large CCGTs, they are characterized by shorter startup times, greater flexibility in partial-load operation, and the ability to quickly adjust power output. This enables them to respond to short-term fluctuations in renewable energy generation, support local grid balancing, and reduce the load on grid nodes during peak demand hours. At the same time, the future role of cogeneration in the integration of renewable energy sources into the district heating sector will be limited and shaped by new regulatory requirements. In accordance with the guidelines set forth in the Energy Efficiency Directive (EED), including the requirements for high-efficiency cogeneration, facilities that use fossil fuels must comply with a direct emissions limit of 270 gCO_2/kWh. This criterion reinforces the importance of cogeneration units operating in actual combined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mode – that is, with the simultaneous use of electricity and heat—and limits the possibility of treating CHP units as sources that operate solely to meet the needs of the electricity market.

This means that the flexibility of cogeneration after 2030 will not consist of arbitrarily increasing electricity production regardless of heat demand. For CHP to maintain its role as a system resource, it must be able to sustain high efficiency and emission levels that comply with regulatory requirements while integrating with heat storage systems and Power-to-Heat technologies. In other words, it is not the cogeneration unit itself, but rather the integrated CHP system – heat storage, Power-to-Heat, and flexible gas-fired sources – that will determine the actual capacity of the combined heat and power plant to support the National Power System.

In the long term, the willingness to ensure fuel transition of new gas-fired units will also be important. Currently, natural gas remains the primary fuel for gas engines; however, the path to decarbonization will require a gradual transition to low- and zero-emission fuels, such as biomethane, hydrogen, or synthetic fuels. In such a model, gas engines could serve as a transitional but technologically adaptable component – provided that their future fuel compatibility is properly designed. As a result, a modern combined heat and power plant becomes a hybrid energy hub, the goal of which is not to maximize the output of a single technology, but to optimize the operation of the entire local system based on weather conditions, energy prices, heat demand, and the needs of the National Power System. This model makes it possible to simultaneously absorb excess renewable energy, limit cogeneration output when it is not needed by the power system, and increase electricity generation during periods of power shortages — while maintaining the core function of combined heat and power plants, which is to ensure the security of heat supply.

The role of heat storage tanks and heat accumulators in increasing the operational flexibility of cogeneration units

Heat storage tanks and heat accumulators are among the most effective tools for increasing the flexibility of district heating systems and combined heat and power plants. Their primary function is to temporarily separate the heat generation process from its distribution. It enables:

- storing excess heat during periods of increased operation of CHP units,
- utilizing stored heat during periods when the combined heat and power plant should reduce its output or respond to signals from the National Power System.

In practice, a heat storage tank allows a combined heat and power plant to generate electricity when the grid needs it most or when energy prices are high – regardless of the current demand for heat.

From the perspective of the National Power System, the heat storage tanks increase the capacity of combined heat and power plants to:

- provide regulatory services,
- reduce electricity production during periods of high renewable energy generation,
- increase generation during peak demand periods.

When combined with Power-to-Heat technologies, thermal storage systems also serve as an indirect form of electricity storage – storing electricity in the form of heat.

The role of Power-to-Heat (P2H) technology in the integration of power and district heating systems

Power-to-Heat technologies enable the conversion of electricity into heat, which can be used directly in a district heating system or stored. Their importance is growing as the variability of renewable energy generation increases and electricity surpluses become more frequent in the National Power System.

P2H can serve as:

- A flexible energy consumer that utilizes surplus energy generated by PV and wind.
- Solutions that enhance the flexibility of district heating systems, particularly when combined with heat storage tanks.
- A tool for optimizing heat production costs by taking advantage of low (and sometimes negative) electricity prices.

Combining P2H with thermal storage allows for the shifting of energy use over time – heat can be generated when electricity is abundant and inexpensive, and consumed when it is needed. As a result, the district heating system becomes an active participant in the energy market, rather than merely a consumer of heat from CHP.

The role of CHP units in the power system after 2035

After 2035, given the high share of renewable energy sources, cogeneration will primarily serve as a flexible, on-demand source of power in the National Power System. Increased volatility in electricity generation will require more frequent intervention by regulatory authorities which can stabilize the system in the following situations:

- low generation from renewable energy sources,
- a sudden increase in demand,
- sudden changes in wind conditions or sunlight.

CHP units, with their wide range of power regulation and high availability, will be able to play a key role in balancing the National Power System. The growing volatility of electricity prices on the wholesale market will further increase the importance of combined heat and power plants as entities that respond to market signals – increasing production during periods of high prices and reducing it during periods of oversupply. However, the CHP’s ability to play this role will largely depend on the degree of integration with heat storage tanks and P2H technologies. These solutions will make it possible to move away from the rigid link between electricity generation and heat demand. In the long term, combined heat and power plants may evolve into multifunctional “power hubs” that combine:

- electricity and heat generation,
- energy storage,
- cooperation with local renewable energy sources,
- provision of system services.

Looking beyond 2035, the importance of cogeneration will increasingly depend on the ability of CHP units to operate flexibly and to integrate with heat storage tanks and Power-to-Heat technologies. This model allows the district heating system to be treated not only as a consumer of electricity, but also as an active component in balancing the National Power System, capable of responding to both periods of surplus and periods of deficit in renewable energy generation.

3. Regulatory and technical risks for cogeneration

Table 3: Regulatory risks for cogeneration.

Regulatory risks for cogeneration	Regulatory risk description
The risk of being unable to develop and support district heating systems as a result of losing the status of an efficient district heating system starting in 2035.	A significant risk to the further development and support of projects related to the transition of district heating systems is the possibility of losing the status of an efficient district heating system starting in 2035 This is due to failure to meet the new criteria set forth in Article 26 of the EED, which means that, from that point on, it will no longer be possible to meet the criteria for an efficient district heating system solely through the required share of heat from high-efficiency cogeneration — for systems based on one or more CHP units, it will be necessary to ensure a share of RES or waste heat. In this context, the key challenge will be the sharp increase in the required share of heat from renewable energy sources or waste heat in the mixed-source option—from a minimum of 5% during the 2028–2034 period to a minimum of 35% starting in 2035. For large urban district heating systems operating in major metropolitan areas, such as Warsaw or Kraków – systems that currently meet the criteria for an efficient district heating system mainly due to a high share of cogeneration – achieving such a level of renewable energy/waste heat may require significant technological and infrastructure investments, as well as ensuring the availability of zero-emission and decarbonized gases. Failure to meet the above criteria will limit access to certain support mechanisms, worsen the terms of investment financing, prevent the development of the heat market in a given location, and make it difficult to stay on track with decarbonization while ensuring the security of heat supply.
The risk of failing to meet the 2035 deadline for the "fuel transition" of CHP units and other gas-fired units, resulting in non-compliance with the EU Taxonomy and failure to meet the conditions of support mechanisms that require compliance with the EU Taxonomy for gas-fired units	A significant risk for new and retrofitted cogeneration units and other gas-fired units is failure to meet the requirement of full transition to renewable or low-emission gases by December 31, 2035, as required by the EU Taxonomy criteria for selected gas-related activities. According to the Complementary Delegated Act to the EU Taxonomy, gas-fired systems may be treated as transitional activities only if they meet strict criteria, including, among others, emission limits and a commitment to transition to renewable or low-emission fuels by the end of 2035. The risk of "fuel transition" is particularly significant for owners of cogeneration units and district heating systems, as compliance with this requirement largely depends on factors beyond their direct control. This applies primarily to the commercial availability of sufficient volumes of decarbonized and zero-emission gases, such as biomethane, renewable hydrogen, or synthetic fuels, as well as the availability of transmission and distribution infrastructure to supply them to district heating sources. Another major constraint may be the cost of these fuels and competition for their use from other sectors of the economy, particularly industry and transportation. The Taxonomy criteria for natural gas are considered challenging, and achieving a full transition to renewable or low-carbon fuels after 2035 may require significant technological and infrastructural changes. Failure to meet this criterion may result in gas investments losing their compliance with the EU Taxonomy, which will have not only reputational and regulatory implications, but also financial ones. The problem may become apparent especially during the acquisition, settlement, or maintenance of investment support (grants – e.g., under the existing programs of the National Fund for Environmental Protection and Water Management) for gas projects, if demonstrating compliance with the EU Taxonomy remains a condition for receiving funding. In practice, this means that cogeneration projects and other gas projects currently planned as a transitional step in the district heating sector's transition may face restrictions on access to financing in the future – or even the risk of having to repay subsidies – if an actual possibility of using decarbonized and zero-emission gases within the required timeframe is not ensured
The risk of tightening the emissions threshold for gas-fired cogeneration in the EU Taxonomy	New gas-fired cogeneration units are being built to meet an emission target of 270 gCO_2/kWh. In January 2025, an advisory body to the European Commission (the Sustainable Finance Platform) recommended lowering the threshold in the Taxonomy to 240 gCO_2/kWh starting in 2025 and to 115 gCO_2/kWh starting in 2030 – gas-fired cogeneration would be considered sustainable only if its emissions were brought into line with this threshold. The proposed change was sudden and not supported by comprehensive analyses. Meanwhile, its implementation would carry a high risk of halting some of the investment projects aimed at reducing emissions and limiting the use of coal-based fuels
Failure to continue the operational support system for the high-efficiency cogeneration	The support system for high-efficiency cogeneration is of interest mainly to investors who wish to take advantage of the cogeneration bonus – this means that the system primarily supports new units with an installed capacity of more than 1 MW and less than 50 MW. The system has many advantages: it supports the development of stable, low-emission units that help balance the power system and allow for the introduction of a new heat stream into local district heating systems, thereby enabling their decarbonization. Meanwhile, 2028 is set to be the final year of the support system for high-efficiency cogeneration (the expected final year for CHP auctions). Any termination of support will likely result in insufficient capacity in cogeneration plants up to 1 MW, which receive special support under EU regulations (the EED emphasizes the need to remove all barriers to the connection of small-scale cogeneration and the possibility of counting every level of emission reduction achieved through the use of small-scale gas cogeneration) and should be similarly supported in national regulations. It is also certain that termination of the support would not encourage generators to blend natural gas with biomethane in cogeneration units due to the lack of dedicated reference prices that take into account the cost of biomethane.
Failure to include cogeneration in the new capacity market	The capacity market has ensured that high levels of generation capacity are contracted for in large-scale cogeneration units. In shaping the new capacity market, the role of cogeneration plants in balancing the system and ensuring available capacity must be taken into account.
Failure to adapt the terms of support in RES auctions to the specific nature of the entities' operations	In the current regulatory environment, investors in biogas plants strongly prefer to build biogas cogeneration units with an installed capacity of up to 1 MW and do not participate in RES auctions for biogas plants, which are intended for larger plants. This is due, among other things, to the risk of failing to deliver 85% of the declared volume of electricity to the grid, given that biogas plants are often granted grid connection terms tailored to intermittent operation — typical of photovoltaic systems (e.g., 8–12 hours of operation per day).
Failure to include in the benchmark tariff transitional technologies used to reduce emissions	Many decarbonization projects in Poland currently involve replacing existing coal-fired units with gas-fired cogeneration plants. In line with the direction of the transition of district heating systems set out in the EED, a gradual transition to renewable gaseous fuels in natural gas-fired units will be necessary to maintain the system's status as an energy-efficient one. However, the cost of producing heat from biomethane – which remains a more expensive fuel than natural gas – is not factored into the benchmark tariff for cogeneration. The reference index for renewable fuels is based on the cost of biomass and does not at all reflect the higher cost of purchase of biomethane. The list of reference indexes in the benchmark tariff should also be supplemented with an index for waste-to-energy plants.

Table 4: Technical risks for cogeneration and measures to overcome these limitations

Technical limitations for cogeneration	Measures to remove limitations
Potential difficulties with availability of fuel (natural gas, biomass) to power the cogeneration unit at a given location	■ Cooperation with gas system operators regarding the possibility of ensuring the timely connection of CHP units to the gas network. ■ Measures to ensure a supportive regulatory environment for the use of biomass for energy purposes.
Insufficient growth in the renewable gas fuels market in Poland	■ Developing a regulatory environment that supports the growth of the renewable fuels market in order to increase the supply of these fuels (in particular, biomethane), ■ Cooperation with gas system operators aimed at removing barriers to the development of the renewable fuels market.
Potential difficulties in connecting a CHP unit to the power grid at a given location	■ Speeding up the process of issuing power grid connection conditions for CHP units, ■ Timely completion of the connection process.
Unavailability of natural gas in certain locations	■ Market research conducted by gas system operators (GAZ-SYSTEM, PSG) aimed at identifying the so-called "white spots." On the gas market in Poland, there is potential and an economic rationale for construction of new gas-fired cogeneration units. ■ Analysis of the profitability of constructing new gas connections in the context of new investment projects.
Inability to connect sufficient power to the power system due to inadequate grid infrastructure in certain locations	■ Investments in the expansion and retrofit of the power grid, ■ Implementation of the measures provided for in the "Grid Act" (Act of March 13, 2026, amending the Energy Law and certain other acts, Journal of Laws, item 516), monitoring the effects of their implementation, and potentially designing further changes to streamline the connection process.
Inability to achieve the required supply temperature for the district heating network under design conditions for high-temperature networks (over 100°C when the cogeneration plant is located far from other generation units)	■ Reform of climate zones in Poland. ■ Adapting regulatory tables to new climatic conditions (a systematic increase in the average annual air temperature) and legal requirements (the need to increase the share of heat from renewable energy sources and waste heat in district heating systems, forcing these systems to operate at significantly lower heat carrier temperatures than at present).

4. The impact of cogeneration and the electrification of district heating on power flows in the power grid – a case study of the Rzeszów CHP Plant

Purpose of the analysis

The starting point for the analysis was the question of what happens in power grids when a district heating system ceases to function as a local source of electricity and begins to act as a significant consumer of it. Combined heat and power plants supply electricity in the immediate vicinity of urban demand, reducing the need to supply a given area from distant sources. In a scenario of deep electrification of district heating – i.e., with the reduction or shutdown of cogeneration units and the replacement of part of the heat production with Power-to-Heat technologies: heat pumps or electric boilers, the same district heating system will have to shift its role from being an electricity supplier for the local area to a major consumer of electricity from the National Power System. A power flow analysis conducted for the Rzeszów CHP Plant examines how changes in the role of local cogeneration affect the operation of the power grid. In particular, the study examined how the loads on the 110/220/400 kV lines and the 400/220/110 kV transformers, comparing two operating conditions: the operation of the Rzeszów CHP plant as a local source of electricity, and a scenario of deep electrification of district heating, in which the shutdown of cogeneration units is accompanied by additional electricity consumption to power Power-to-Heat technology. Grid overloads refer to situations in which power lines, transformers, or other components of the power infrastructure operate beyond their permissible technical parameters, which may limit the grid's ability to safely transmit and distribute energy. The specific objective was therefore to determine the impact of the operation, reduced output, and shutdown of the cogeneration units at the Rzeszów CHP Plant on the National Power System, as well as to assess the effects of a scenario involving increased power consumption related to the decarbonization of the heating sector and the development of Power-to-Heat technologies on grid operational safety.

The analysis was conducted using the branch of PGE Energia Ciepła S.A. – Rzeszów Combined Heat and Power Plant as a case study – that is, a facility that generates electricity and heat for the city of Rzeszów. The technical analysis took into account the generating units at the Rzeszów CHP Plant, with a total capacity of 137 MW, including a 101 MW combined-cycle gas turbine unit, four 7 MW gas engines, and an 8 MW waste-to-energy plant. The generating units of the Rzeszów CHP Plant are connected to the 110 kV bays at the 110/15 kV Rzeszów CHP Plant, which means the power source is directly connected to the regional high-voltage grid supplying the urban area.

This analysis was prepared as an initial assessment of the impact of the local combined heat and power plant's operations on power flows in the power grid. Its purpose was not to fully simulate all possible operating conditions of the National Power System, but to determine whether and how a change in the principles of operation of a cogeneration unit and an increase in electricity consumption for heating purposes might affect the loads on the transmission and distribution networks.

Assumptions for the analysis

The analysis was performed for two time horizons: 2029 and 2035. For the year 2035, the projections include investments resulting from the transmission network development plan for 2025–2034 and the development of offshore wind farms (OWFs) in accordance with the requirements of the Act on the promotion of electricity generation from OWFs.

The calculations were performed for a range of operating conditions of the National Power System, including:

- winter peak demand with low RES generation at a temperature of 0°C,
- winter peak demand with high RES generation at a temperature of 10°C,
- summer peak load with high photovoltaic generation at a temperature of 30°C,
- summer peak load with high discharge of electricity storage facilities (ESF) at a temperature of 25°C,
- summer peak demand with high RES generation at a temperature of 25°C.

An analysis of power flows and voltage levels was conducted for both normal and emergency operating conditions, i.e., n-1 operating states of the grid resulting from the emergency shutdown of grid infrastructure components.

The analysis compared two operating scenarios for the Rzeszów CHP Plant:

1. Option 1: operation of the CHP sources at the Rzeszów CHP Plant at near-full capacity, i.e., 137 MW
2. Option 2: a scenario involving the extensive electrification of district heating, in which 130 MW of Power-to-Heat capacity was added while cogeneration units were shut down.

Options structured in this way make it possible to assess the overall effect of replacing local cogeneration with a large-scale consumption of electricity for district heating needs. The analysis does not isolate the effect of source shutdown per se, but focuses on a scenario that is relevant from the perspective of the deep electrification of the district heating sector.

Results for 2029

Looking ahead to 2029, a comparison of the option to operate the Rzeszów CHP Plant at 137 MW with the deep electrification scenario shows an increase in the load on selected grid components, particularly in the 110 kV grid directly connected to the Rzeszów area. In the option of operation of the Rzeszów CHP Plant, i.e., while maintaining local cogeneration, overloads primarily affect – the 220 kV Kielce – Radkowice and 220 kV Kielce – Kielce Piaski lines. In the deep electrification scenario, which involves the shutdown of the Rzeszów CHP Plant and adding 130 MW of Power-to-Heat (P2H) capacity, additional overloads occur in the 110 kV grid, and there are limitations on the available power capacity for P2H technology.

During the winter peak with high renewable energy generation, when the Rzeszów CHP plant is operating at 137 MW, the load on the 220 kV Kielce–Radkowice line reaches 108%, and the 220 kV Kielce–Kielce Piaski line reaches 119%. In the deep electrification scenario, these values are 110% and 121%, respectively, indicating an increase in the load on these grid components. In addition, during the summer peak with high renewable energy generation, the deep electrification scenario results in overloads on the 110 kV grid directly connected to the Rzeszów area. The load on the 110 kV Budy Głogowskie – Rzeszów CHP Plant line has reached 112%, and that on the 110-kV Budy Głogowskie – Rzeszów line has reached 122%. The available power capacity for Power-to-Heat technology in this operation status is 80 MW.

The effects are even more pronounced in the summer peak scenario with high PV generation. In the deep electrification scenario, the load on the 110 kV Budy Głogowskie–Rzeszów CHP Plant line reaches 127%, on the 110 kV Wysoka Głogowska – Rzeszów CHP Plant line reaches 110%, the 110 kV Rzeszów – Wysoka Głogowska line reaches 110%, and the 110 kV Budy Głogowskie –Rzeszów line reaches as high as 137%. The available power capacity for Power-to-Heat technology in this operation status is 60 MW. The results for 2029 show that the deep electrification scenario not only leads to increased loads on selected components of the transmission network, but above all reveals local infrastructure constraints in the 110 kV grid. This means that replacing local cogeneration with large-scale electricity consumption for heat production should be analyzed in conjunction with the operational and development capabilities of the distribution network.

Table 5: Risks to network operations in individual options. The percentage of grid load is shown in parentheses.

	Winter peak demand with low RES generation at a temp. of 0°C	Winter peak demand with high RES generation at a temp. of 10°C	Summer peak load with high discharge of electricity storage facilities at a temp. of 25°C	Summer peak with high RES generation at a temp. of 25°C	Summer peak with high PV generation at a temp. of 30°C
OPTION 1 CHP Plant 137 MW	nothing is exceeded	220 kV line Kielce - Radkowice (108%) 220 kV line Kielce - Kielce Piaski (119%)	nothing is exceeded	nothing is exceeded	nothing is exceeded
OPTION 2 Power to Heat 130 MW	nothing is exceeded	220 kV line Kielce - Radkowice (110%) 220 kV line Kielce - Kielce Piaski (121%)	nothing is exceeded	110 kV line Budy Głogowskie - Rzeszów EC (112%) 110 kV line Budy Głogowskie - Rzeszów (122%) Available capacity: 80 MW	110 kV line Budy Głogowskie - Rzeszów EC (127%) 110 kV line Wysoka Głogowska - Rzeszów EC (110%) 110 kV line Rzeszów - Wysoka Głogowska (110%) 110 kV line Budy Głogowskie - Rzeszów (137%) Available capacity: 80 MW

Results for 2035

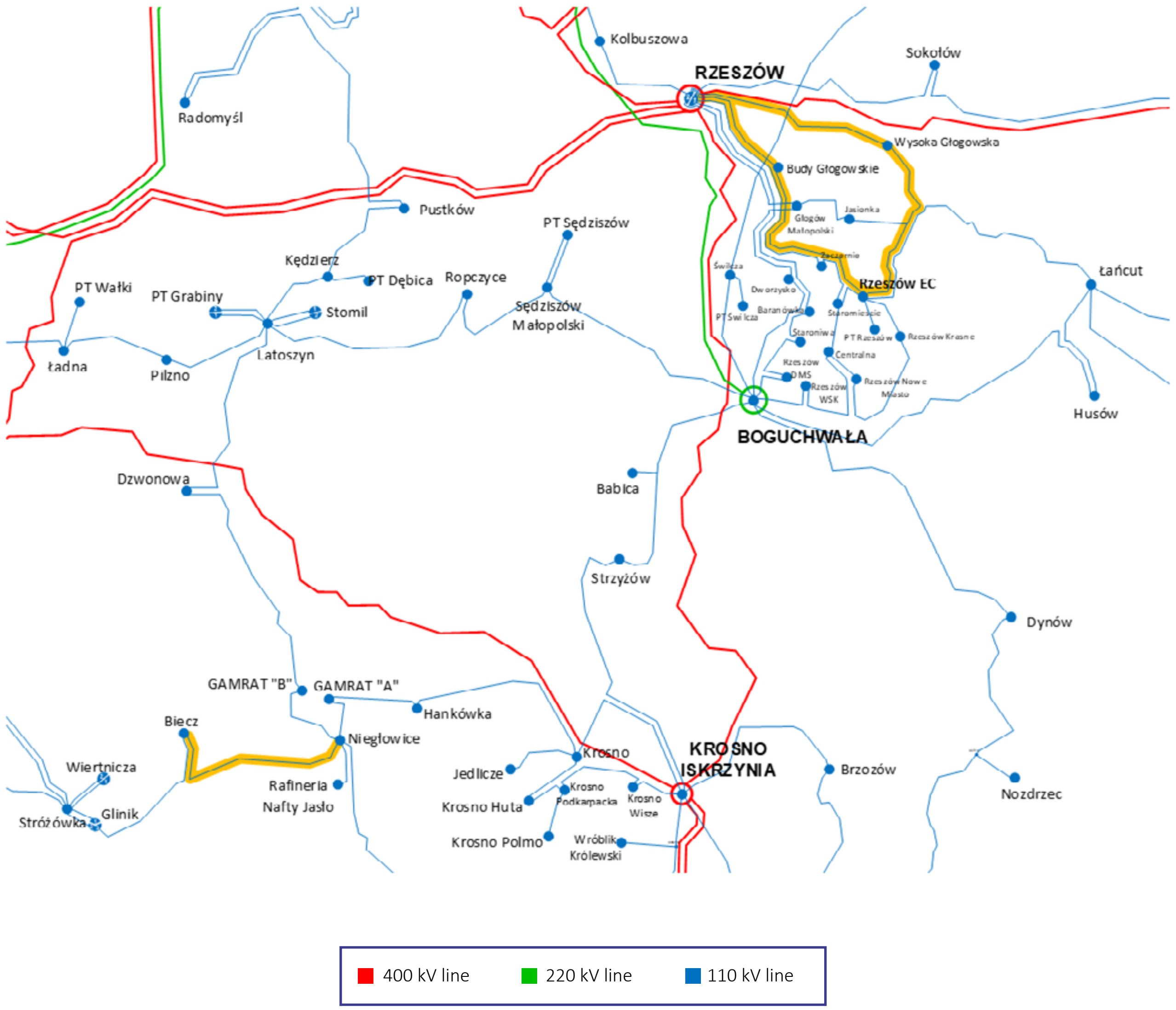
By 2035, with the Rzeszów CHP Plant operating at full capacity, in most of the analyzed scenarios, there will be no instances of the 110 kV grid directly connected to the Rzeszów area exceeding its capacity. The exception is the overload on the 220 kV Kielce–Kielce Piaski line during the winter peak scenario with high RES generation, when the load reaches 101%. This result should be interpreted with caution, as it pertains to a component of the 220 kV grid and may be due to broader operating conditions of the National Power System (KSE), rather than solely to the operation of the analyzed combined heat and power plant.

In the deep electrification scenario – which involves the shutdown of the Rzeszów CHP Plant and adding 130 MW of Power-to-Heat capacity – the permissible loads on selected grid components are exceeded by 2035. The load on the 220 kV Kielce–Kielce Piaski line is at 103%, while during the summer peak, with high renewable energy generation, the load on the 110 kV Niegłowice–Biecz line is at 110%. The available power capacity for Power-to-Heat technology in this operation status is 0 MW, which indicates significant infrastructure constraints for implementing a deep electrification scenario without a parallel assessment of the power grid's capacity. The results for 2035 show that a scenario in which the cogeneration facility stops supplying electricity and the district heating system becomes a major consumer of energy from the National Power System places greater demands on the transmission and distribution infrastructure. In this scenario, the grid must simultaneously replace the energy previously generated locally and meet the new, significant electricity consumption needs required to generate heat. Of particular importance here are the overloads occurring at the 110 kV level, as they indicate possible local infrastructure constraints that are significant from the perspective of the distribution system operator.

Table 6: Risks to network operations in individual options. The percentage of grid load is shown in parentheses.

	Winter peak demand with low RES generation at a temp. of 0°C	Winter peak demand with high RES generation at a temp. of 10°C	Summer peak load with high discharge of electricity storage facilities at a temp. of 25°C	Summer peak with high RES generation at a temp. of 25° C
OPTION 1 CHP Plant 137 MW	nothing is exceeded	220 kV line Kielce - Kielce Piaski (101%)	nothing is exceeded	nothing is exceeded
OPTION 2 Power to Heat 130 MW	nothing is exceeded	220 kV line Kielce - Kielce Piaski (103%)	nothing is exceeded	110 kV line Niegłowice - Biecz (110%) Available capacity: 0 MW

Chart 1: A network diagram with lines at risk of overload marked in orange. The 220 kV Kielce–Radkowice line and the 220 kV Kielce–Kielce Piaski line are not shown in the image due to its size.



Interpretation of the results: local cogeneration as a factor limiting grid loads

The example of Rzeszów confirms that a combined heat and power plant located in an urban area affects the operation of the power grid not only as a generation source but also as a factor that reduces the need for electricity supplies from external sources. When the cogeneration units at the Rzeszów CHP Plant are in operation, part of the local demand for electricity is met at the point of consumption, which reduces the need to transmit power from more distant sources and reduced the load on certain parts of the grid.

In a **scenario of deep electrification**, the shutdown of local cogeneration is accompanied by the emergence of a new, large-scale demand for electricity to meet heating needs. This means that the power grid must simultaneously replace the energy previously generated locally and accommodate the additional energy consumption from the National Power System. This effect results in increased loads on selected components of the power grid, particularly at the 110 kV level, which is directly connected to the Rzeszów area. From the perspective of the Distribution System Operator (DSO), the consequence of such a scenario is an increased risk of overloads in the 110 kV grid and the need to upgrade grid components to higher permissible current-carrying capacities. The results for the **scenario of deep electrification** are particularly significant, as they demonstrate a direct link between the electrification of heating, the reduction in local cogeneration, and investment needs on the distribution network side. At the same time, the results concerning the 220 kV lines in the Kielce–Radkowice and Kielce–Kielce Piaski areas should be interpreted with caution. Overloads on these components also occur in the option of operation of the Rzeszów CHP Plant, which means that their primary cause may stem from broader operating conditions within the National Power System, rather than solely from the operation of the analyzed combined heat and power plant. From the perspective of the report; however, the 110 kV grid overloads that occur in the **scenario of deep electrification** are of key importance, as they point to local infrastructure constraints that may become apparent during large-scale electrification of the heating sector. Since the analysis was conducted for a single specific district heating system and its local network conditions, the results should not be automatically applied to all district heating systems in Poland. To provide a more comprehensive assessment of systemic impacts, similar calculations should also be carried out for other large cities and district heating nodes where combined heat and power plants serve as local sources of electricity and heat. However, the results for Rzeszów show that the relation between cogeneration, the electrification of district heating, and power grid loads should be analyzed as early as the planning stage of the transformation of local district heating systems.

Consequences for the National Power System Operator and the Distribution System Operators (OSD)

The results of the analysis indicate that the transformation of district heating cannot be viewed solely as a change in fuel or heat source technology. A scenario of deep electrification, in which the shutdown of local cogeneration is accompanied by a significant increase in electricity demand for Power-to-Heat technologies, may lead to increased grid loads, reveal transmission and distribution constraints, and necessitate additional infrastructure investments.

The significance of this proposal extends beyond Rzeszów. In many large cities, combined heat and power plants are located near centers of demand and they are connected to the 110 kV grid. If the process of electrifying district heating is carried out without taking into account the role of local cogeneration in power distribution, this could lead to an increase in the demand for electricity supplied from distant sources, increased loads on transformer substations, and higher costs for operation and expansion of the power grid.

For this reason, the development of Power-to-Heat and other forms of heating electrification should be designed as part of an integrated CHP system – heat storage – Power-to-Heat – the power grid, rather than as a simple substitution of local cogeneration with electricity consumption from the National Power System. This approach makes it possible to benefit from the potential of heat electrification without passing on excessive costs and risks to grid operators and end users.

The identified overloads are not merely a technical problem; they also translate into potential costs for grid operators: the need to retrofit lines, increase the capacity of grid components, adapt power supply systems, and maintain additional balancing reserves during periods of high energy consumption by Power-to-Heat technologies.

Summary

An analysis of the Rzeszów CHP Plant shows that a scenario of deep electrification of district heating – in which the district heating system ceases to supply electricity locally while simultaneously drawing significant volumes of energy for Power-to-Heat technologies – may pose significant challenges for the power grid. In this scenario, the load on the 110 kV grid increases, as does the need to source power from more distant generation facilities. This means that the transformation of district heating should be planned in conjunction with the development of power grids, and cogeneration should be treated as a local system resource whose value encompasses not only heat and electricity production but also its impact on power distribution, grid operational reliability, and infrastructure costs.

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5. Transformation of district heating systems using cogeneration – an expert economic analysis

The purpose of this chapter is to assess the extent to which cogeneration can serve as an economically viable component of the transformation of district heating systems of various scales. The analysis compares selected investment options based on an economic model that calculates ***LCOH*** (***Levelized Cost of Heat*** – the discounted weighted-average cost of heat generation) for two examples of heat market: a small system with a capacity of 35 MW and a large system with a capacity of 600 MW. Four options of technological combinations are proposed for each heat market, which allow a given district heating system to meet the criterion of an efficient district heating system in successive time frames, as defined by Article 26 section 1 of the EED. These options differ in terms of the available power generated by cogeneration technology; this is intended to illustrate how the LCOH varies for individual technology configurations and to demonstrate the impact of the technology choice – with or without cogeneration – on costs in the district heating and power systems.

The analysis was performed for the years 2026–2050. The model in each year selects the most cost-effective heat sources, taking into account not only the fulfillment of the requirements of an efficient district heating system, but also the variable costs of production, and – for each year – arranges the stack of generating units writing them into the demand resulting from the heat profile for a given option of the district heating system. This means that the heat production of each unit is based on the demand of a given market and the price relations in a given year. The generating units with the lowest variable cost operate at the base of the district heating system. To also capture the impact of individual options on the power system, a comparable volume of electricity and heat production was assumed for the years 2030–2044, and the shortfall in electricity generation in the scenarios with a lower share of cogeneration was offset by generation from gas-fired power plants. This makes it possible to assess not only the cost of heat generation, but also the broader economic implications of the separate and combined models, particularly in terms of fuel costs, CO_2 emission allowances, and emissions. A key factor affecting the results of the analysis and the selection of optimal heat generation technologies involves the macroeconomic and market assumptions adopted, which determine the cost and price environment in which district heating systems operate. This report uses an updated set of assumptions, developed based on the latest available data and agreed upon by PTEC members, taking into account current economic, regulatory, and market trends. The values used include, among other things, forecasts for fuel prices, electricity prices, and CO_2 emission allowances, as well as macroeconomic indicators such as inflation. Detailed macroeconomic and technical-economic assumptions are presented in Appendix I to the Report.

Examples of heat markets

The regulations adopted as part of the "Fit for 55" package, which stem from the EU's climate and energy policy objectives – in particular, the Energy Performance of Buildings Directive (EPBD), will have an impact on the long-term prospects for the development of district heating systems. The adopted legal solutions (especially in the area of energy efficiency of buildings) will cause:

- Increased pace of thermal retrofit of existing buildings to reduce final and primary energy demand;
- Tightening technical guidelines for new residential construction toward high energy efficient and passive houses.

This will result in a reduction of the heat market due to reduced heat demand for the existing mass of buildings and lower demand from new connections of buildings from the primary and secondary markets (with reduced demand for central heating), which will have a significant impact on the structure of individual heat markets. The effect of the above conditions on the level of heat demand will depend on the initial state of thermal retrofit of buildings currently connected to the district heating system. Changes in demand resulting from the introduction of savings due to rising heat prices are already being observed in district heating systems. For the purposes of the analysis, it was assumed that the buildings connected to the district heating system had mostly undergone at least partial thermal retrofit in the past. Ultimately, a decrease in heat demand is projected, which will not be able to be fully compensated for by new central heating connections.

The rate of reduction of heat markets will depend on the duration of the validity of new regulations (including transition mechanisms) and the potential for new connections. We currently expect volume loss of 30% to 40% by 2050 (in smaller markets with limited contracted capacity for hot water heating).

Two heat markets were selected for analysis, differing in terms of the nature of their heat demand curves, including varying shares of domestic hot water and different levels of demand during transitional and summer periods.

Chart 9 shows examples of a demand curve for heat markets in the 20–50 MWt capacity range (defined as 35 MWt for the purposes of this report). These markets are characterized by a relatively low share of hot water demand relative to larger cities and systems. This demand can be noticed in particular in the summer period.


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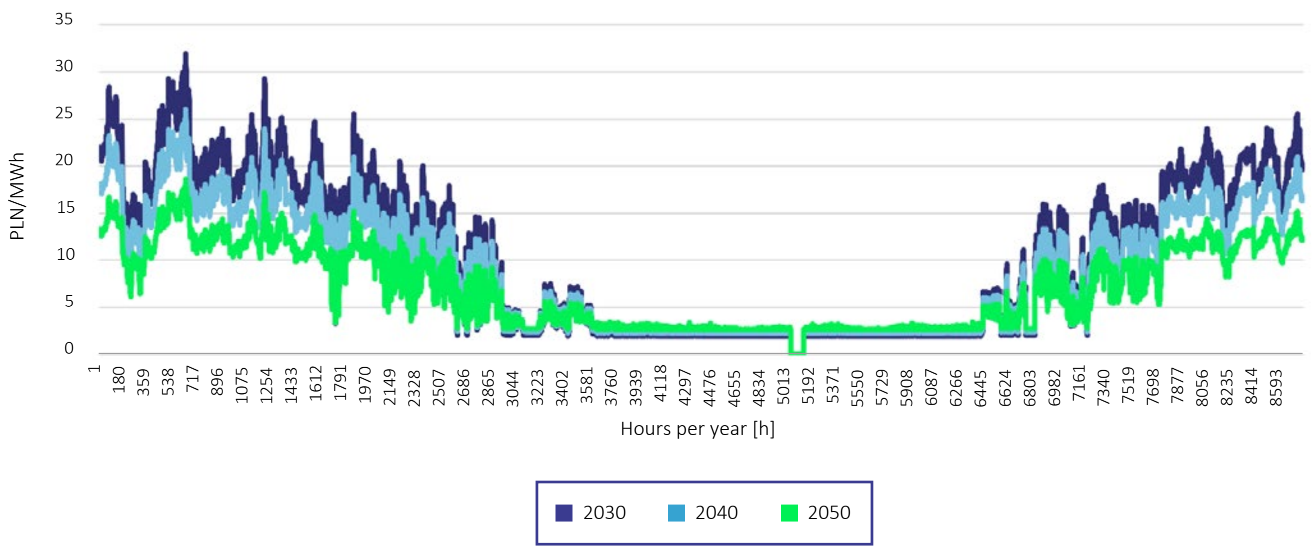
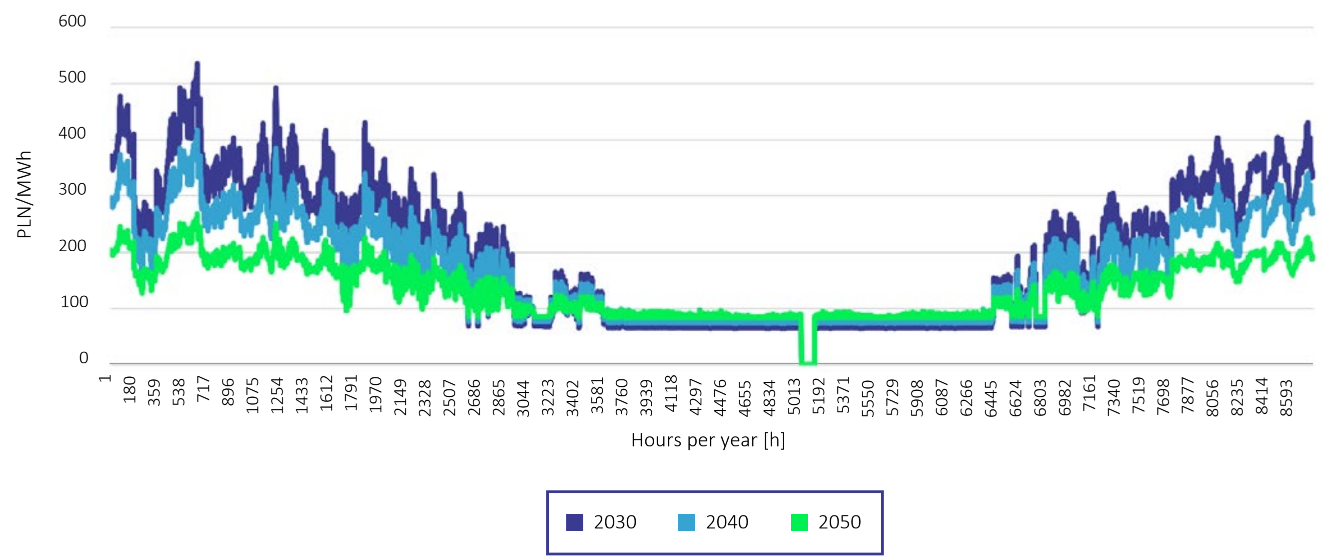
Chart 9: Heat market with a contracted capacity of 35 MWt, source: PTEC's own study



In the case of a large district heating system; on the other hand, the share of domestic hot water demand and the demand for heat during the transitional periods of fall-winter and spring-summer is already significant.

Chart 10: Heat market with a contracted capacity of 600 MWt, source: PTEC's own study



Technology options:

Four different technology options were analyzed for each market, which are technically feasible and will enable the requirements of an efficient district heating system to be met over successive time frames, as defined in the EED. The analysis was prepared on the basis of technological options, which were developed for each heat market from each power range, taking into account forecasts of the development of heat demand. A detailed summary of technology options is presented below. It should be noted that the installed thermal capacity assumed for the source is about 120% of the network's peak demand. For simplicity, a coupling coefficient of 1.0 was assumed for gas-fired cogeneration. Options that include heat pumps include additional capacity in peak units, due to the limited possibility of heat pump operation with full capacity during periods of low temperatures, in order to secure power during peak heat demand.

HEAT MARKET 35 MWth

Table 7: Examples of technology options for the 35 MW market, expressed in MWt.

Technology	Commencement of operations	Option 1 (O MWt CHP)	Option 2 (5 MWt CHP)	Option 3 (10 MWt CHP)	Option 4 (15MWt CHP)
Waste heat	2030	0.5	0.5	0.5	0.5
Gas-Fired Cogeneration	2030	0	5	10	15
Heat pumps I	2030	2.5	2.5	2.5	2.5
Heat pumps II	2035	5	5	5	5
Heat pumps III	2040	5	5	5	5
Biomass-fired boilers	2030	2.5	2.5	2.5	2.5
Gas-fired boilers	2030	10	10	10	10
Electrode boilers	2030	30	25	20	15
Total thermal power [MWt]		**55.5**	**55.5**	**55.5**	**55.5**
Capacity without heat pumps [MWt]		**43.0**	**43.0**	**43.0**	**43.0**
Heat accumulator	2030	2 thousand m^3	2 thousand m^3	2 thousand m^3	2 thousand m^3

HEAT MARKET 600 MWth

Table 8: Examples of technology options for the 600 MW market, expressed in MWt.

Technology	Commencement of operations	Option 1 (O MWt CHP)	Option 2 (100 MWt CHP)	Option 3 (200 MWt CHP)	Option 4 (300 MWt CHP)
Waste heat	2030	10	10	10	10
Gas-Fired Cogeneration	2030	0	100	200	300
Heat pumps I	2030	75	25	25	25
Heat pumpsII	2035	25	50	50	50
Heat pumps III	2040	50	50	50	50
Biomass-fired boilers	2030	25	25	25	25
Gas-fired boilers	2030	285	285	285	285
Electrode boilers	2030	400	300	200	100
Total thermal power [MWt]		**870**	**845**	**845**	**845**
Capacity without heat pumps [MWt]		**720**	**720**	**720**	**720**
Heat accumulator	2030	52 thousand m^3	52 thousandm^3	52 thousand m^3	52 thousand m^3

Analysis results

This chapter presents the results of an economic analysis used to determine the capital expenditures and LCOH values for individual technology options in two examples of heat market.

In the analysis, the technology options were selected in such a way that a 3-stage investment process would have the potential to meet regulatory requirements in the run up to 2050. The various technologies in the stack are selected prioritizing both the lowest cost of heat generation and the achievement of at least the minimum volumes of heat from high-efficiency cogeneration, RES and waste heat, as specified in the definition of an efficient district heating system.

It should also be noted that there may be new opportunities around 2040 related to the option of converting existing gas generating units to allow the use of green hydrogen, biomethane or biogas, which should further increase the potential to accelerate the decarbonization of the district heating sector. The adoption as a boundary condition of a given modeled district heating system's fulfillment of the “efficient district heating system” criterion is due to the crucial importance of this status for the operation of a given system. Its loss is associated with serious consequences for both energy companies engaged in heat generation and heat transmission and distribution, including, among others:

- a significant restriction on the possibility of obtaining investment support for the construction or modernization of the district heating network and investment support for generation units;
- the actual lack of market development opportunities for connecting new consumers and buildings;

- destabilizing the operation of the district heating network resulting from the need to connect RES plants, particularly to connect a large number of small RES plants (which will not equate to a large volume of heat from RES);
- the emergence of stranded costs resulting from the construction of generating units that guarantee energy security;
- enabling end users to disconnect; from the district heating network;
- the emergence of more individual heat sources (not only using RES),
- but also it has an impact on air quality, as emissions of harmful substances and greenhouse gases will increase due to the aforementioned effects, and the phenomenon of low emissions will worsen. Thus, it has important implications for all parties involved in local heat markets.

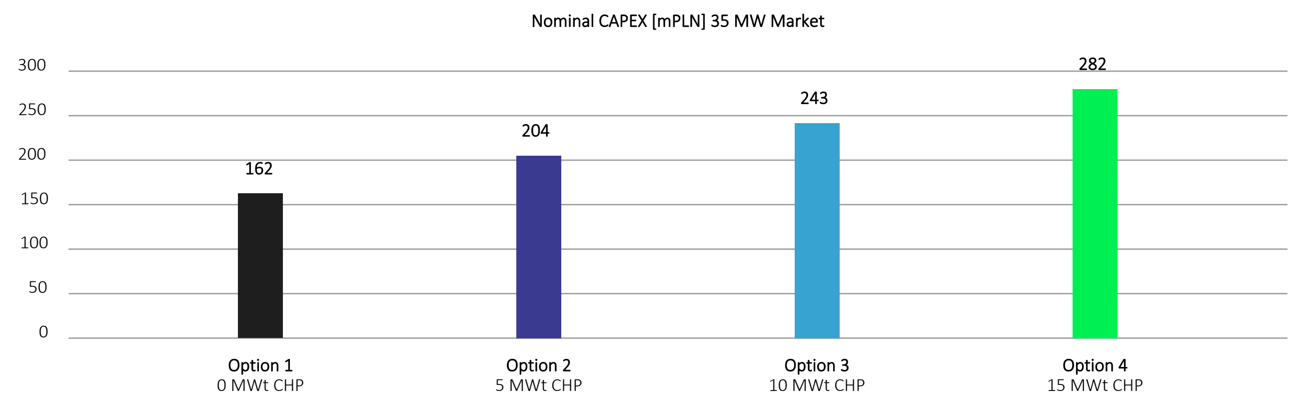
The mathematical optimization model used in the analysis aims to minimize the total cost of heat generation in district heating systems. It comprises the following components:

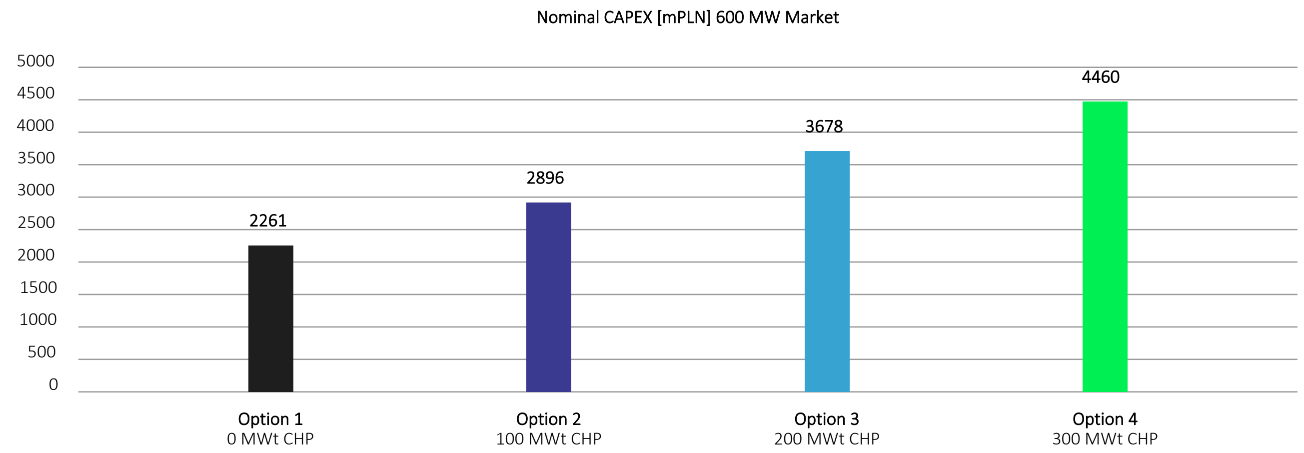
- CAPEX – which includes capital expenditures;
- OPEX – which includes costs of overhauls;
- Costs – which include the cost of fuel, the cost of greenhouse gas emission allowances and fixed operating costs;
- Period of analysis – 2026 – 2050.

The model, based on a typical heat demand curve, calculates the used thermal capacity of the sources. Based on the thermal efficiency of the sources, a work stack is established in order from the most efficient (i.e. the cheapest) source after the variable cost of generation. The model takes into account regulatory requirements, i.e. the need to meet the criterion of an efficient district heating system, which involves taking into account the required shares of heat from RES or waste heat or heat from high-efficiency cogeneration in a given district heating system. Such a stack of units fills the demand of the heating market in each of the options. As a consequence of the above, there are years where heat from RES installations is not the cheapest, but must be produced for regulatory reasons, or a surplus of RES is obtained in relation to the requirements to meet the criterion of an efficient district heating system, when it is cheaper than other generating units. The model is intended to calculate the average discounted unit heat price on generation, which ensures the profitability of a given option at IRR = 8% over the period 2026-2050.

The model discounts all expenditures (CAPEX, OPEX), takes into account revenues from the sale of electricity, and assumes that electricity from high-efficiency cogeneration is supported by the high-efficiency cogeneration support mechanism at PLN 200'26/MWh, and then determines a heat price that results in NPV = 0 over the entire forecast period.

Chart 11: Capital expenditures estimated for options 1–4 for the 35 MW and 600 MW markets.





Based on the heat production plan, which was developed taking into account regulatory requirements as well as existing and projected market conditions, the electricity generation potential for each investment option was estimated. The analysis covered both the volume of electricity that could be generated and the factors affecting how and when the generating units operate. The highest electricity generation volume for both heat markets under analysis was achieved in option 4. At the same time, there is a significant impact from increasingly stringent regulatory requirements, in particular the requirement to ensure a share of renewable energy sources and/or waste heat starting in 2035, as well as the requirement to achieve an emission factor not exceeding 270 g CO_2/kWh for high-efficiency cogeneration units. These factors lead to a reduction in the number of operating hours for cogeneration units, shifting their operation toward off-peak operation and making their operation more dependent on current heat demand.

The analysis indicates that when determining the installed capacity of cogeneration units, it is crucial to minimize the risk of oversizing them, which could result in underutilization of production capacity, excessive capital expenditures, and, consequently, a reduction in the economic efficiency of the investment project.

In this context, option 3 represents the most balanced solution, both for the heat market with a demand of 35 MW, as well as for a market with a demand of 600 MW, providing an optimal balance between electricity generation volume, compliance with regulatory requirements, and system operational flexibility. The balance between the power generated by cogeneration units and the power consumed from the grid to power P2H devices is also significant. Given their interdependence and the most technically optimal way of integrating with the power system – in both small and large heat markets – option 3 is also the best choice (i.e., 10 MWt CHP and 200 MWt CHP, respectively). To fully reflect the impact of individual investment options on the electricity market, a simulation was conducted in which the main assumption is that electricity and heat production would remain the same in each analyzed case during the years 2030 – 2044. In areas where there is no cogeneration or where it is less extensive than in option 4, it is assumed that gas-fired power plants will be used to generate the shortfall in electricity. The results of the analysis are presented in Charts 12–15.

Chart 12: Resultant electricity generation for options 1–4 for the 35 MW market.

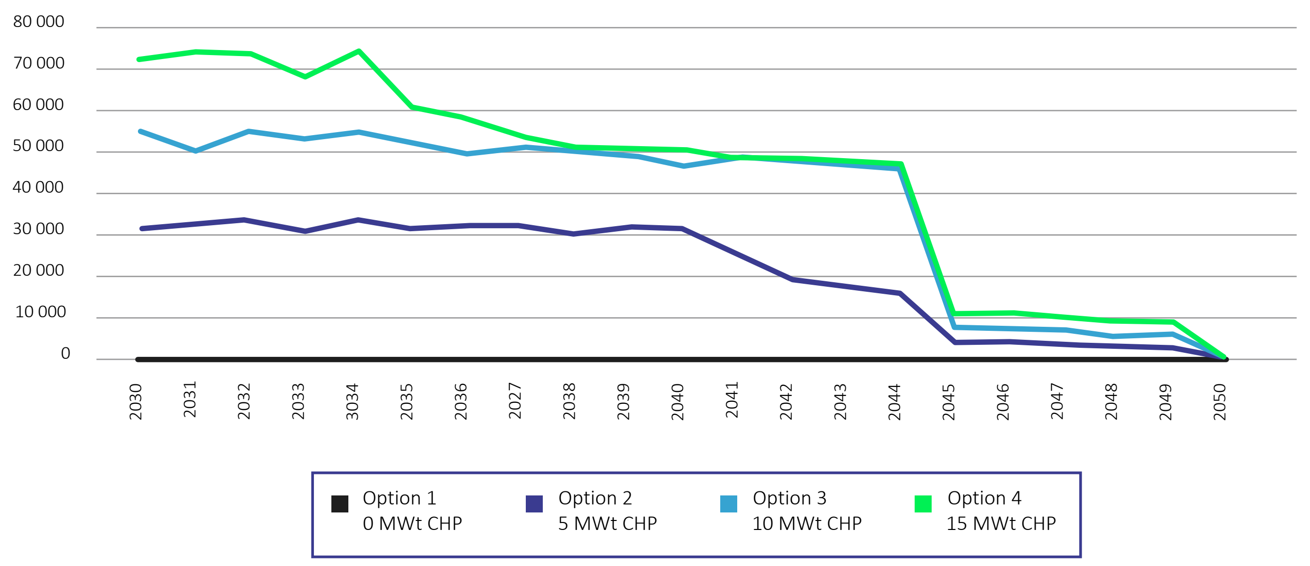


Chart 13: Maximum power output and maximum power input for options 1–4 for the 35 MW market.

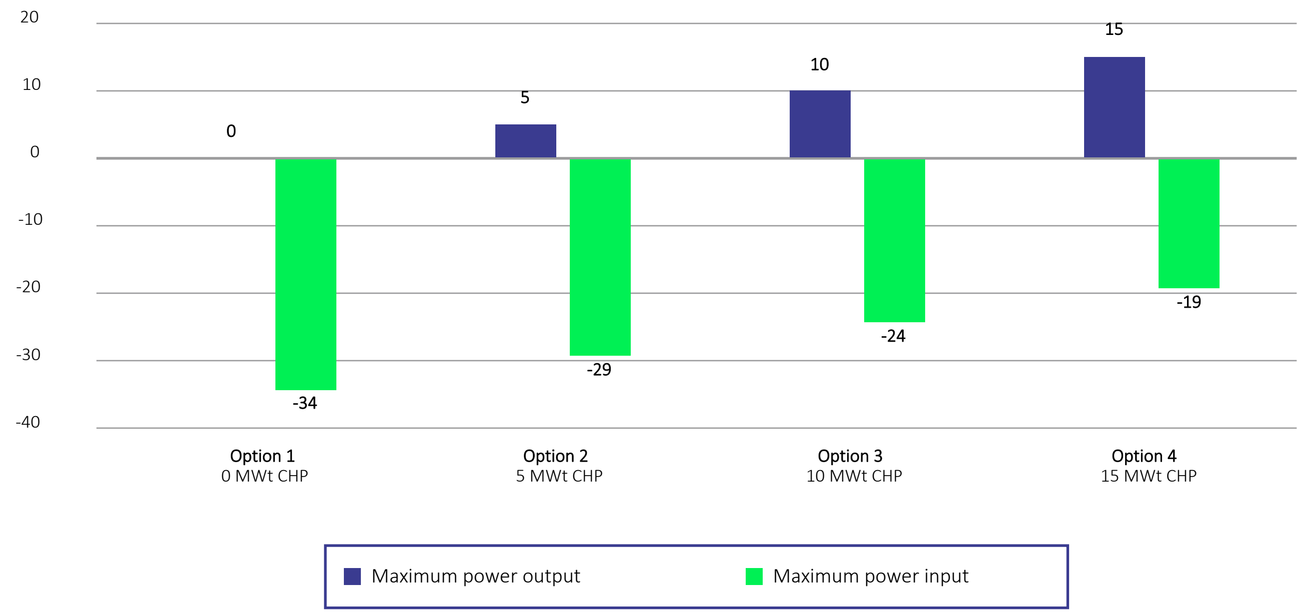


Chart 14: Resultant electricity generation for options 1–4 for the 600 MW market.

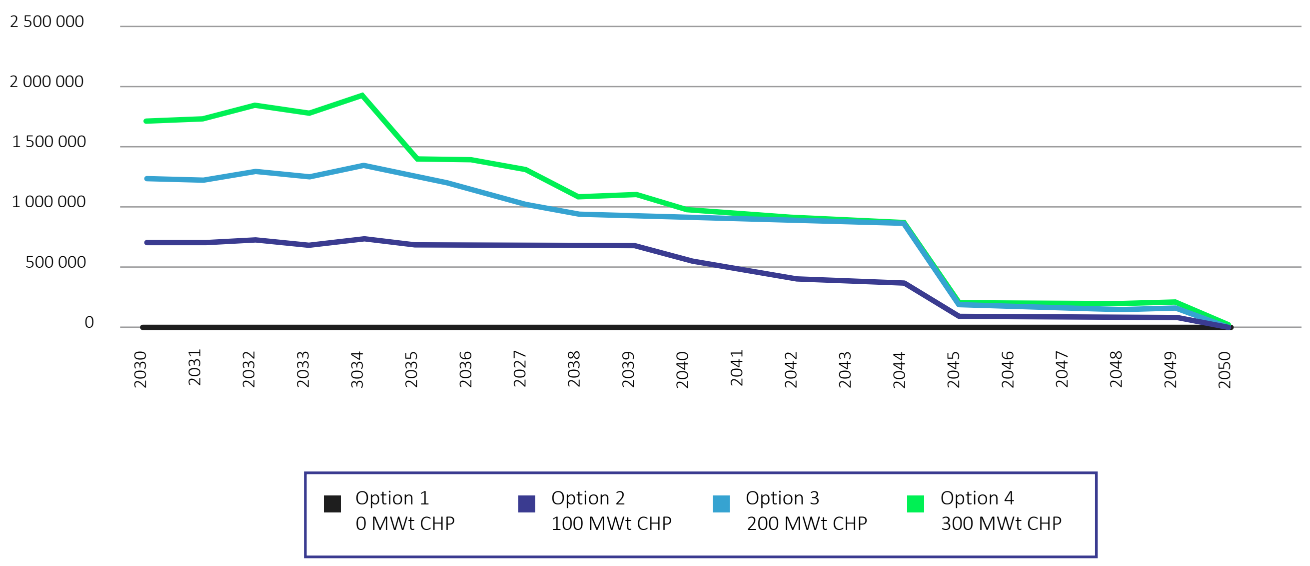
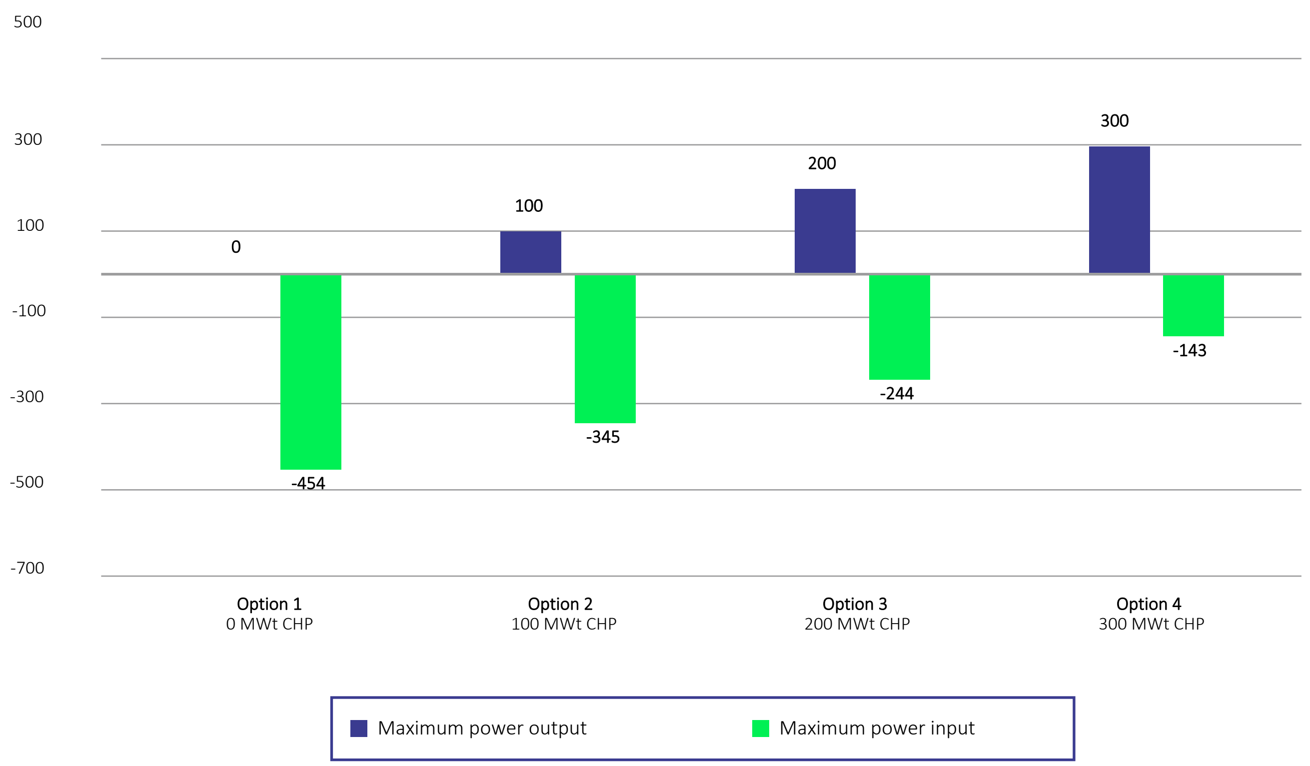
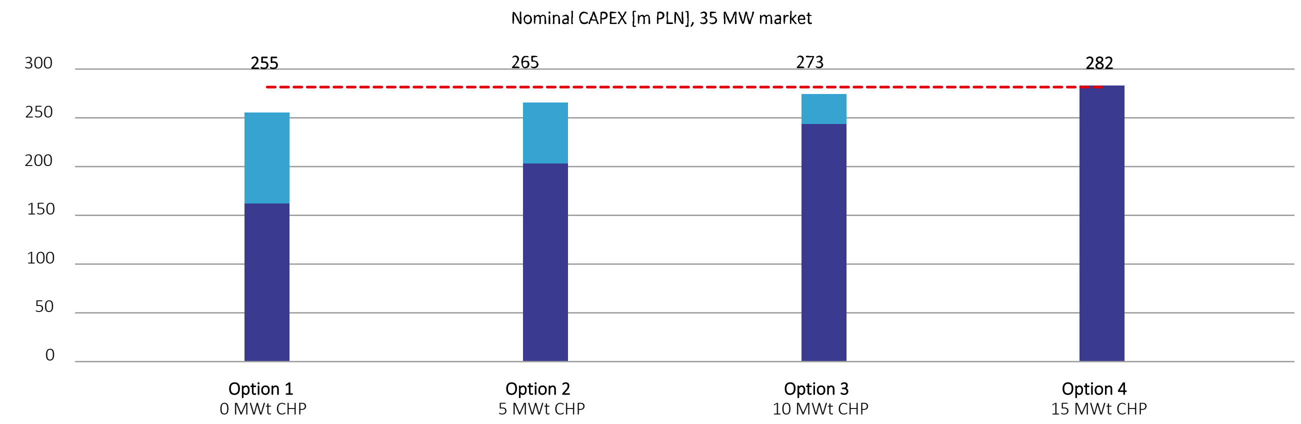


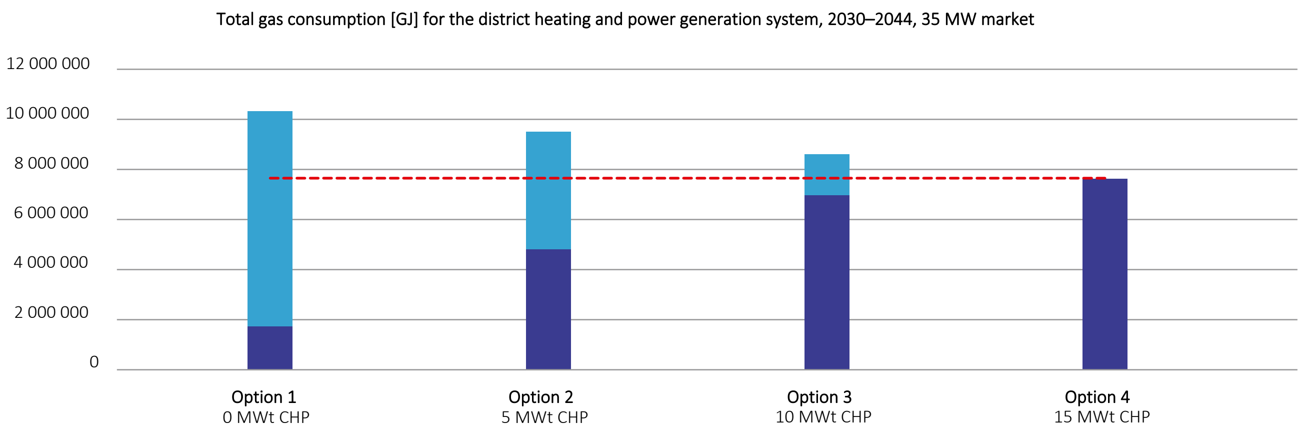
Chart 15: Maximum power output and maximum power input for options 1–4 for the 600 MW market.

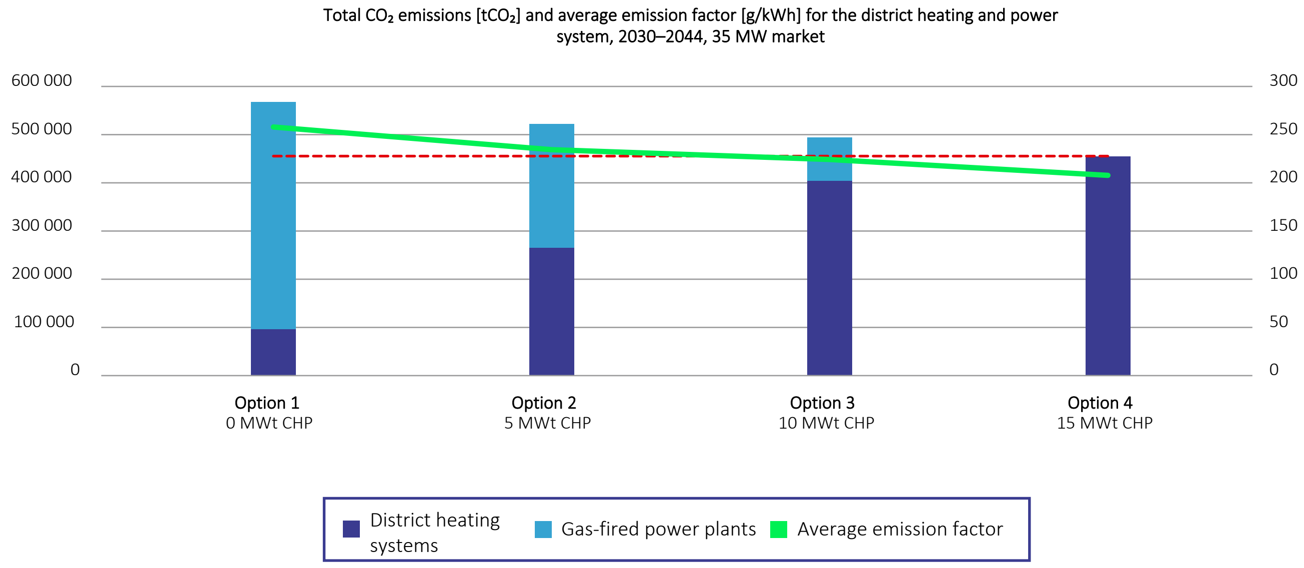


The analysis presented shows that, despite incurring slightly lower total capital expenditures for both district heating systems and the construction of additional power output at gas-fired power plants, the economy ultimately incurs higher costs for heat and electricity generation in a separated system than in a combined system, which is due to higher costs for purchasing gas and CO_2 emission allowances. Higher initial investment costs are offset by lower operating expense for combined heat and power generation as early as 1.5–2.5 years, depending on the option – and even sooner for larger markets. The environmental impact is also significant – options with a lower share of cogeneration result in higher CO_2 emissions, which is why the use of cogeneration systems also supports the decarbonization of the economy.

Chart 16: Comparison of capital expenditures, gas consumption, CO_2 emissions, and the costs of gas and CO_2 emission allowances based on a 35 MW market (assuming an average gas price of 167.36 PLN/MWh and a purchase price for CO_2 emission allowances of 118.37 EUR/t for the period 2030–2044 – for detailed assumptions, see Appendix 1).







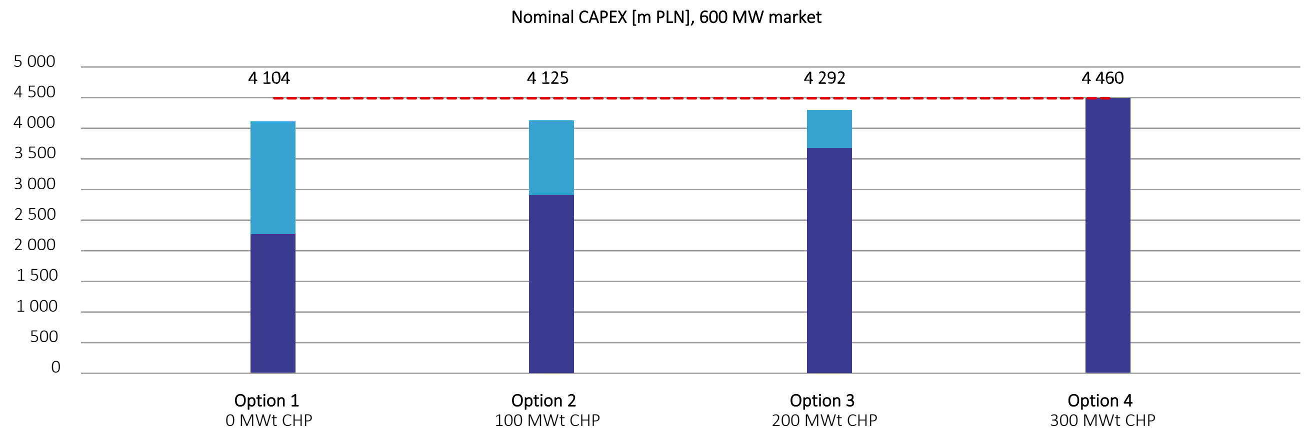
For an example heat market with a demand of 35 MW, a scenario was analyzed in which the same amount of electricity and heat is generated in each option. In the options involving smaller cogeneration units, electricity would be generated by separate gas-fired power plants that would need to be constructed. Based on this assumption, it can be seen that the total CAPEX for options 1, 2, and 3 **is lower by 27 m PLN (9.7%), 17 m PLN (5.9%), and 8 m PLN (3.0%), respectively.**

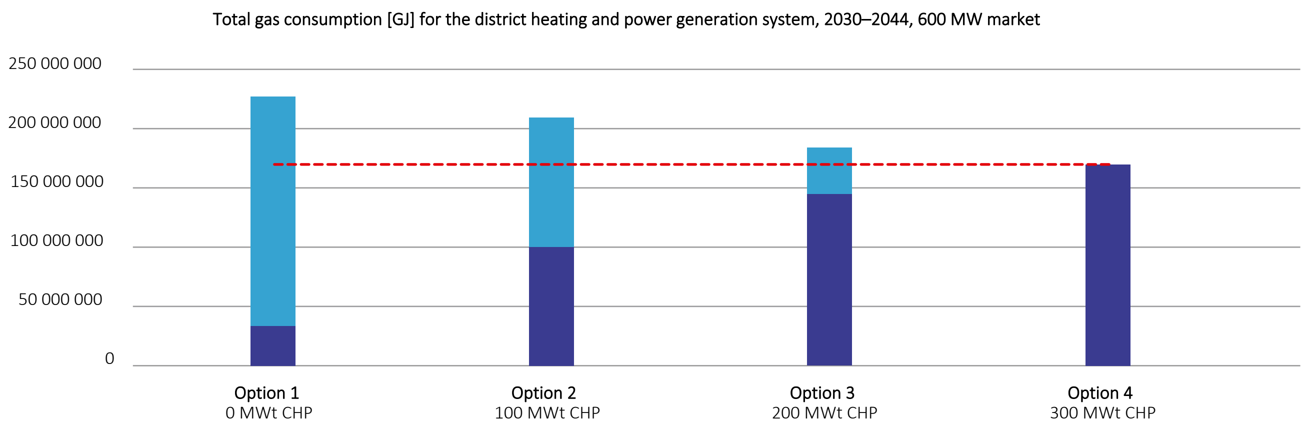
Gas-fired power plants generate electricity with lower efficiency than cogeneration units, which in turn results in higher fuel consumption and gas costs. In the scenario under analysis, **the average annual costs associated with this in options 1, 2, and 3 are 8 m PLN, 5 m PLN, and 3 m PLN higher, respectively.**

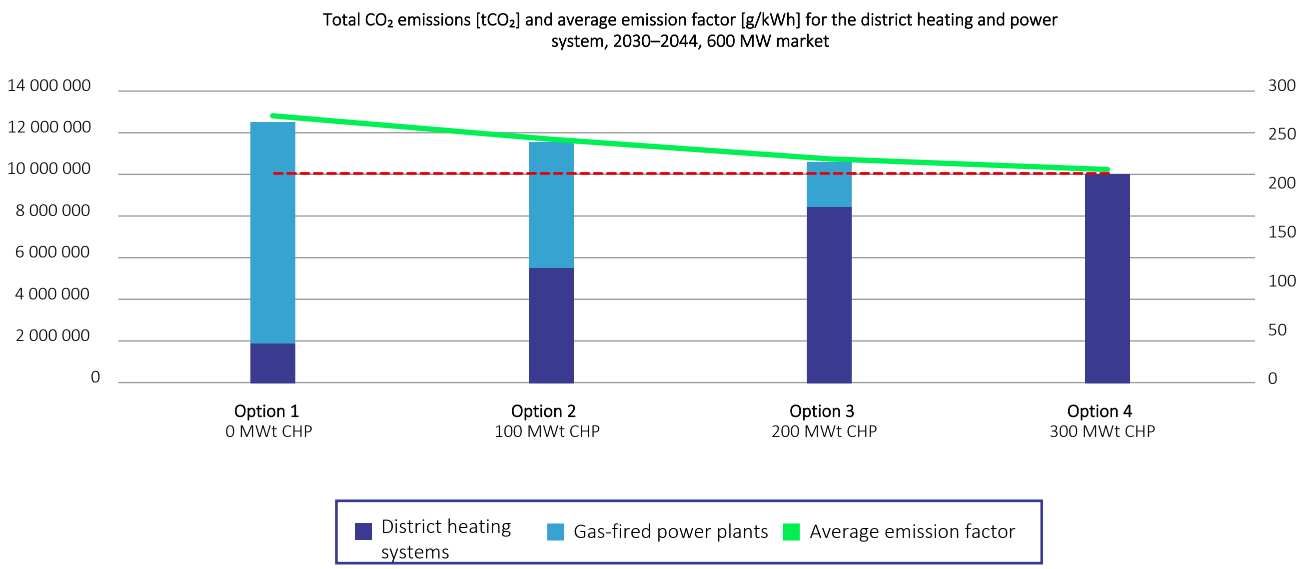
Lower efficiency leads to higher CO_2 emissions, which in turn results in **higher average annual costs for purchasing CO_2 emission allowances in options 1, 2, and 3 – by 4 m PLN, 2 m PLN, and 1 m PLN, respectively.**

CONCLUSION: Despite lower capital expenditures, the variable costs of electricity generation (fuel costs and CO_2 emission allowances) rise significantly compared to those of cogeneration units with the same generation capacity.

Chart 17: Comparison of capital expenditures, gas consumption, CO_2 emissions, and the costs of gas and CO_2 emission allowances based on a 35 MW market (assuming an average gas price of 167.36 PLN/MWh and a purchase price for CO_2 emission allowances of 118.37 EUR/t for the period 2030–2044 – for detailed assumptions, see Appendix 1).







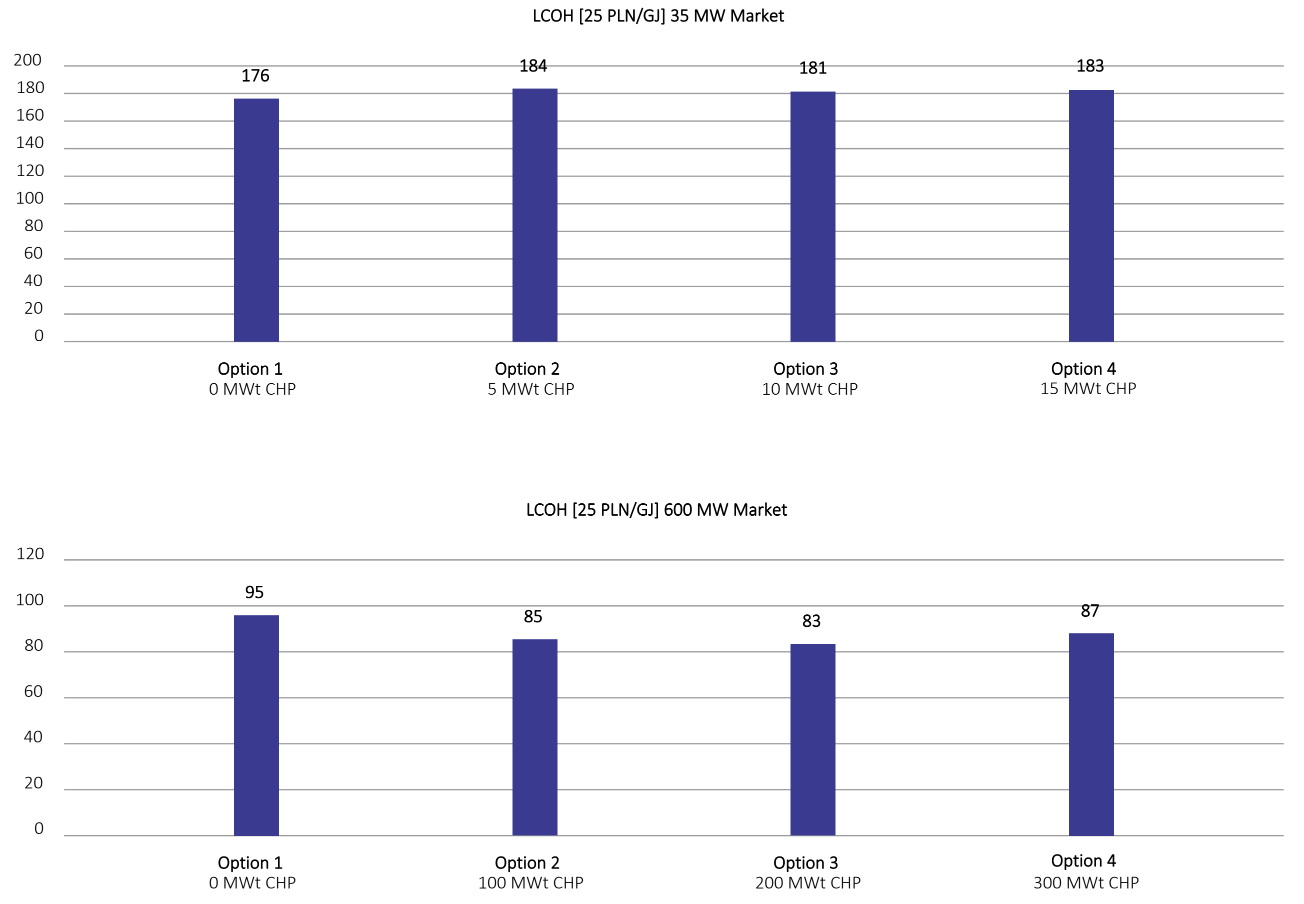
For an example heat market with a demand of 600 MW, a scenario was analyzed in which the same amount of electricity and heat is generated in each option. In the options involving smaller cogeneration units, electricity would be generated by separate gas-fired power plants that would need to be constructed. Based on this assumption, it can be seen that the total CAPEX for options 1, 2, and 3 **is lower by 356 m PLN (8.0%), 335 m PLN (7.5%), and 168 m PLN (3.8%), respectively.**

Gas-fired power plants generate electricity with lower efficiency than cogeneration units, which results in higher fuel consumption and gas costs. In the scenario under analysis, **the average annual costs associated with this in options 1, 2, and 3 are 172 m PLN, 116 m PLN, and 40 m PLN higher, respectively.**

Lower efficiency leads to higher CO_2 emissions, which in turn results in **higher average annual costs for purchasing CO_2 emission allowances in options 1, 2, and 3 – by 79 m PLN, 44 m PLN, and 16 m PLN, respectively.**

CONCLUSION: Despite lower capital expenditures, the variable costs of electricity generation (fuel costs and CO_2 emission allowances) rise significantly compared to those of cogeneration units with the same generation capacity.

Chart 18: LCOH for the 35 MW and 600 MW markets.



The LCOH results for the 35 MW market indicate that the lowest levelized cost of heat generation can be achieved under option 1. Options 2–4, on the other hand, show a slightly higher LCOH level – about 3–4% higher. This is primarily due to the low share of domestic hot water demand, which is particularly evident during the summer. With a required share of heat from renewable energy sources and/or waste of at least 35%, the operating time for cogeneration units decreases, which results in slightly higher heat generation costs than in the option without cogeneration.

The LCOH, on the other hand, is different in the large 600 MW market. In this case, options 2, 3, and 4 yield values that are 11%, 13%, and 8% lower, respectively, than option 1 (without cogeneration). Additionally, in the event of a large heat market with a heat demand of 600 MW, it has been estimated that relaxing the requirement for the share of heat from renewable energy sources and waste heat in the energy mix (RES / waste heat + cogeneration = 80%) from 35% to 15% would allow for the postponement of some investments in renewable energy capacity to the period after 2040. This solution generates measurable savings in capital expenditures (CAPEX) and allows for an increase in electricity production capacity between 2035 and 2039 by an **average of approximately 15% in option 3 and approximately 22% in option 4 compared to the baseline scenario (600 MW market), and by approximately 5% in option 3 and 27% in option 4 (35 MW market).** Options 1 and 2 were not included in the analysis of this type of regulatory modification because, in this case, the share of cogeneration in the assumed set of sources is too low to meet the combined requirement of an 80% share of renewable energy sources, waste heat, and cogeneration.

Chart 19: LCOH indicators for the 35 MW and 600 MW markets, taking into account the relaxation of the minimum share requirements for renewable energy and waste heat for the years 2035–2039.

As a result, lowering the required share of renewable energy sources and waste heat from 35% to 15% leads to additional savings in the weighted average cost of heat generation (LCOH) and increases the operational flexibility of cogeneration units in options 3 and 4, both from the perspective of the district heating system and the power system.

Based on data from the report “Heat Energy in Numbers – 2024,” 206 830 TJ of heat was supplied to off-takers connected to the grid in 2024, which – assuming a **reduction in the cost of heat generation by 3 PLN/GJ – translates to annual savings of approximately 620 mln PLN.** Based on calculations for a heat market with a demand of approximately 35 MW, a decrease in the LCOH is observed in options 3 and 4. Despite this adjustment, these values remain slightly higher than in option 1, in which the system's definition requirements are effectively met solely through a high share of renewable energy sources and waste heat, without the use of cogeneration.

Conclusions:

- The loss of electrical capacity in the power system caused by the gradual phase-out of coal-fired cogeneration units will create a gap that can only be partially filled by gas-fired cogeneration units.
- Investment decisions regarding the selection of electrical and thermal capacity in gas-fired cogeneration units will be closely determined by heat market forecasts and regulatory changes to the EED Directive.
- Larger district heating systems, with a high proportion of domestic hot water and significant heat demand during transition periods, offer the greatest potential for utilizing cogeneration. In smaller systems, this potential is also significant, but there is also greater flexibility in the selection of renewable energy sources, which should be the primary factor in determining the selection of technology stack.
- An increase in LCOH of approximately 3–4% resulting from the use of combined heat and power generation in low-capacity markets indicates their greater potential for faster, full decarbonization and electrification. The investor’s final decision should be based strictly on the projected heat demand curve, as well as the availability of gas, biomass, and waste heat, and on factors that increase the efficiency of P2H sources.
- After 2045, cogeneration capacities may be used as emergency response units in the electricity market, thereby ensuring that the system’s electricity demand is met.
- The total CO_2 emissions for the district heating and power generation systems (assuming the same volume of heat and electricity is generated in each option) indicate lower emissions in options that include gas-fired cogeneration. The higher the capacity of a cogeneration plant, the lower the total CO_2 emissions and gas consumption for heat and electricity generation, which translates into a real reduction in generation costs.
- Lowering the renewable energy sources and/or waste heat requirement for 2035–2039 from the required minimum of 35% to 15% of the total 80% share of heat production from renewable energy sources and/or waste heat and high-efficiency cogeneration will provide greater flexibility for cogeneration units in the heat and electricity markets, while also yielding additional savings on the LCOH.
- Given the scale of heat supplied to off-takers connected to the system, even a relatively small reduction in LCOCH may cause a significant economic impact across the entire sector. With 206 830 TJ of heat supplied to off-takers in 2024, a reduction in the cost of heat generation by 3 PLN/GJ would result in potential annual savings for the economy of approximately 620 mln PLN.
- Cogeneration units ensure a reliable supply of heat for high-temperature systems during their gradual retrofit.
- By investing in cogeneration units, located mainly in larger cities, we reduce transmission losses in power systems, thereby significantly lowering the costs of their retrofit. The fewer CHP units there are, the greater the load on the power system, particularly because it necessitates a significant expansion of the transmission network, which carries energy over long distances. This problem would be exacerbated by radical electrification of large-scale district heating systems.

6. Summary and recommendations

The analysis presented in the report confirms that cogeneration remains one of the key resources for the transformation of district heating systems and for supporting the National Power System. Its importance stems not only from the scale of its heat and electricity generation, but above all from its location near the largest urban centers of demand, its availability, and its potential for integration with heat storage units and Power-to-Heat technologies. Given the growing share of renewable energy sources, the variability of generation, and the ongoing electrification of district heating systems, combined heat and power plants can serve as local energy security resources, supporting the power balance during periods of insufficient renewable generation and enabling the utilization of excess electricity during periods of high renewable energy generation. At the same time, the report's findings indicate that reducing cogeneration or replacing local electricity generation with large-scale off-take from the National Power System is not neutral in terms of either the power systems or the transformation costs. A flow analysis for the Rzeszów CHP Plant shows that decommissioning local cogeneration units and the development of Power-to-Heat technology could increase loads on the 110 kV system and reveal local infrastructural constraints. In turn, an economic analysis of representative heat markets indicates that options without cogeneration may lead to higher total costs, greater gas consumption, and higher CO_2 emissions, especially if the missing electricity generation must be made up by additional gas-fired sources operating to meet the needs of the National Power System. For this reason, the transformation of the district heating system requires a regulatory framework that will allow high-efficiency cogeneration to be maintained and developed as part of an integrated system: CHP – heat storage units – Power-to-Heat – power system. Stable and predictable support mechanisms, the ability to finance investments commensurate with their actual scale, the adaptation of EU criteria to the pace of transformation of large urban district heating systems, and the mitigation of risks related to the availability of decarbonized fuels and infrastructure are of key importance. The recommendations below outline the most important regulatory changes needed to mitigate these risks and ensure that cogeneration can continue to support the security of heat supply, local balancing of the National Power System, and the decarbonization of the sector.

Table 9: Recommendations – EU regulations.

Direction of the change	Main assumptions of the change	Statutory instrument / document
Relaxation of the requirement for a minimum share of heat from renewable energy sources and/or waste heat as set forth in the criteria for an efficient district heating system starting in 2035, in Article 26 of the EED	The introduction of a more gradual growth path for the minimum required share of heat from RES and/or waste heat in district heating systems under the criterion involving high-efficiency cogeneration – as part of the criteria set forth in Article 26 of the EED, which will take effect on January 1, 2035 – up to a maximum of 15%. Currently, the criteria call for a sharp increase in the share of renewable energy and/or waste heat from between 5% (the requirement for 2028–2035) and 35% (the requirement for 2040–2045).	Energy Efficiency Directive
Linking the "fuel transition" requirement for natural gas-powered units by 2035 to the actual availability of zero-emission fuels and infrastructure under the EU Taxonomy	Linking the "fuel transition" requirement to the actual availability of fuel and infrastructure. It should be advocated to introduce a mechanism into the EU Taxonomy that makes the obligation to fully transition to decarbonized gases contingent on the commercial availability of appropriate fuels and transmission and distribution infrastructure. The current requirement is particularly challenging for owners of combined heat and power plants, as the availability of biomethane, hydrogen, or synthetic fuels does not depend directly on the investor in a cogeneration unit, but rather on the development of the fuel market, system infrastructure, and national and EU policies. Proposed change: Introduce a provision stating that failure to meet the fuel requirement after 2035 does not automatically result in the project losing its compliance with the EU Taxonomy if the operator (the plant owner) demonstrates that the non-compliance is due to the unavailability of fuel or infrastructure, despite having exercised due diligence.	Technical eligibility criteria for natural gas-fired units – activities 4.29–4.31 of Commission Delegated Regulation No. 2022/1214.
Ensuring legislative stability regarding emission standard for high-efficiency cogeneration in the EU Taxonomy	For the EU Taxonomy, we advocate maintaining the emissions threshold for high-efficiency cogeneration at 270 g CO_2/kWh throughout the entire transformation period. An investor who is currently building or retrofitting a cogeneration unit that meets the applicable emissions criteria should be ensured that the project will not lose its regulatory eligibility shortly after it is commissioned. The stability of this criterion is crucial for investment predictability, project bankability, and mitigation of the risk that newly constructed units will require additional, costly modifications before reaching the target payback period. Maintaining a stable emission cap does not mean abandoning decarbonization – rather ensuring a reasonable transition period for the investments needed to replace coal-fired units. High-efficiency gas-fired cogeneration remains essential for ensuring the security of heat supply and for balancing the National Power System locally, particularly during periods of limited RES generation. Excessive variability in the EU Taxonomy criteria could increase capital costs, limit access to financing, and slow down the retrofitting of district heating systems at a time when it is essential to replace capacity and ensure continuity of supply.	Technical eligibility criteria for natural gas-fired units – activities 4.29–4.31 of Commission Delegated Regulation No. 2022/1214.
Adjusting the notification thresholds and aid intensities in the GBER to reflect the actual scale of investments in district heating systems, renewable energy sources, and high-efficiency cogeneration	We advocate raising the notification thresholds for investments in high-efficiency cogeneration, renewable energy sources, and district heating systems to 150 mln EUR per company per investment project. The current thresholds do not reflect the actual scale and costs of modern transformation projects, particularly large-scale investments in combined heat and power plants, district heating systems, heat storage units, renewable energy sources, and high-efficiency cogeneration. It is also recommended to increase the basic aid intensity to 45% of eligible costs for investments covered by Articles 58 and 64 of the GBER. This change is justified by the rise in investment costs, inflation in the costs of materials and services, the scale of retrofitting required in district heating systems, and the limited ability to finance investments using heating tariffs. In addition, it is reasonable to raise the threshold for small projects eligible for increased aid intensity to 5 mln EUR, so that this instrument reflects the actual scale of even smaller district heating investments.	Draft amendment to the Commission Regulation on block exemptions for state aid (GBER) – in particular Article 58 Aid for the promotion of energy from re newable sources and high-ef ficiency cogeneration" and Article 64 „Investment aid for district heating and cooling systems";
Introduction of an additional bonus to the aid intensity for investments carried out in accordance with climate neutrality plans for district heating systems	We advocate introducing an additional increase in the aid intensity of 15 percentage points for investment projects in district heating systems carried out in accordance with the climate neutrality plans referred to in Article 10b(4) of the EU ETS Directive. The bonus should cover investments in district heating systems, renewable energy sources, high-efficiency cogeneration, and technologies that support the transformation and flexibility of power systems, provided they are part of the path toward decarbonizing district heating systems. The justification for this approach is the particularly high level of investment needs in countries and district heating systems with high emissions and limited capacity to finance the transformation. An additional bonus would increase the feasibility of the projects needed to decarbonize district heating systems and mitigate the risk of investment delays.	Draft amendment to the Commission Regulation on the General Block Exemption Regulation (GBER) – in particular Articles 58 and 64; link to the climate neutrality plans referred to in Article 10b(4) of Directive 2003/87/EC, i.e., the EU ETS Directive

Table 10: Recommendations – national regulations.

Direction of the change	Main assumptions of the change	Statutory instrument / document
Transfer of unused funds related to pending calls for applications for the individual cogeneration bonus to the cogeneration bonus "budget"	Due to a lack of interest among producers in participating in calls for applications for the individual cogeneration bonus – as reflected by the fact that the last call was finalized in 2021 – and given that this situation is expected to persist through 2026, the pool of funds that will remain "unused" under the CHP call for applications (approximately 15 bln PLN) should be transferred to the auction-based support system (in the form of a cogeneration bonus), which currently constitutes the most important and critical mechanism for operational support for high-efficiency cogeneration.	Regulation on the maximum quantity and value of electricity from high-efficiency cogeneration eligible for support and the unit amounts of the guaranteed bonus
Improving the current system of operational support for high-efficiency cogeneration	Given the practical experiences of producers who have received support in the form of a cogeneration bonus or a guaranteed bonus, the following recommendations for improving this mechanism should be noted: ■ an extension of the deadline for the first generation of electricity from high-efficiency cogeneration in a new cogeneration unit or a significantly retrofitted cogeneration unit, starting from the date of the auction / call for applications, from 48/60 months to 60/72 months, respectively; ■ an extension of the deadline for obtaining a final building permit from 12 to 24 months, which will mitigate the risk of producers losing the support they have received in the event of changes to project execution schedules; ■ new regulations providing for extended deadlines for the first generation of energy at a new or significantly retrofitted cogeneration unit and for obtaining a building permit could have been applied to auctions awarded prior to the effective date of the Act; ■ eliminating the risk that companies that have won an auction for a cogeneration bonus or a call for applications for an individual cogeneration bonus will fail to fulfill their obligation to begin generating energy within the specified timeframe (3 years) – repealing the penalties; ■ eliminating the excessive reporting obligation for electricity producers in high-efficiency cogeneration who do not participate in the support system, as well as for producers for whom the amount of the individual guaranteed bonus during the previous calendar year was 0 PLN/MWh.	Act on the promotion of electricity from high-efficiency cogeneration – the proposed amendments are included in the government's draft law amending certain acts to deregulate the power sector (Sejm Document No. 2578)
Maintaining the current solutions for obtaining decisions on environmental conditions to ensure the certainty of the investment process for the construction or retrofit of high-efficiency cogeneration units to support energy transformation	We advocate maintaining the current wording of the provisions that allow a decision on environmental conditions to be made immediately enforceable and permit the implementation of investment decisions until the decision on environmental conditions becomes final. A departure from current legislative solutions governing environmental procedures poses a serious threat to the ability to meet project execution schedules for the construction and retrofitting of cogeneration units and, as a result, creates the risk of delays in transformation investment projects.	Act on providing access to information on the environment and its protection, participation of the public in environmental protection, and on environmental impact assessment
Inclusion of new types of generation mix in the benchmark tariff	We advocate for introducing changes to the cogeneration tariff system that take into account new types of generation mix used to reduce coal consumption. These changes should include expanding the list of benchmark indicators to cover municipal waste / RDF used in ITPO and biomethane blended with natural gas (or used on its own) in gas-fired cogeneration units.	Energy Law Act; Regulation on the detailed rules for setting and calculating tariffs and settling accounts for heat supply
Capacit markety	We advocate safeguarding and emphasizing the role of cogeneration units as a key element in stabilizing the Polish power sector within the new capacity market.	Capacity Market Act
Continuation of the CHP support system	We advocate: 1. Extending the support system for high-efficiency cogeneration (beyond 2048) 2. Additional incentives in the support system for small-scale cogeneration plants with a capacity of less than 1 MW. Introducing an additional bonus for investors who decide to blend natural gas with renewable gaseous fuels (biomethane) – for example, by implementing a dedicated reference price that takes into account the cost of biomethane.	Act on Support for High-Efficiency Cogeneration
Climate zone reform	The applicable climate zones have an impact on the regulatory tables for heat, which in turn influence the restrictions on grid connection not only for RES plants but also for distributed cogeneration sources, particularly gas engines. It is advisable to reduce the temperatures specified in the regulatory tables.	System Operation Regulation
RES auctions for cogeneration	We advocate expediting the legislative process for the amendment to the Renewable Energy Sources Act (the so-called "Wind Farm and Biomethane Act"), which reduces the electricity supply requirement for biogas plants in renewable energy auctions to 65%.	Act on RES
Release from the obligation to purchase heat for energy undertakings operating within a district heating network that is part of an energy-efficient district heating system, including the one that achieves this status based on the criterion of the share of heat from cogeneration	The RED II Directive (Article 24), as amended by the RED III Directive, does not establish an absolute obligation to purchase heat from renewable energy sources or waste heat, but rather provides an incentive mechanism to connect such sources. At the same time, Article 24(5)(d) provides for the possibility of refusing connection and purchase, particularly when the system meets the criteria for an efficient district heating system. EU regulations do not require a purchase obligation for these systems, regardless of whether they maintain their energy-efficient status through the use of energy from renewable energy sources, waste heat, or high-efficiency cogeneration.	Act on RES

Appendix I - Assumptions for Economic Analysis

MACROECONOMIC ASSUMPTIONS

Chart 1. EUR/PLN exchange rate, *source: PTEC's own study based on the Guidelines of the Ministry of Finance on the use of uniform macroeconomic indicators, July 2025, and average quotations of the National Bank of Poland.*

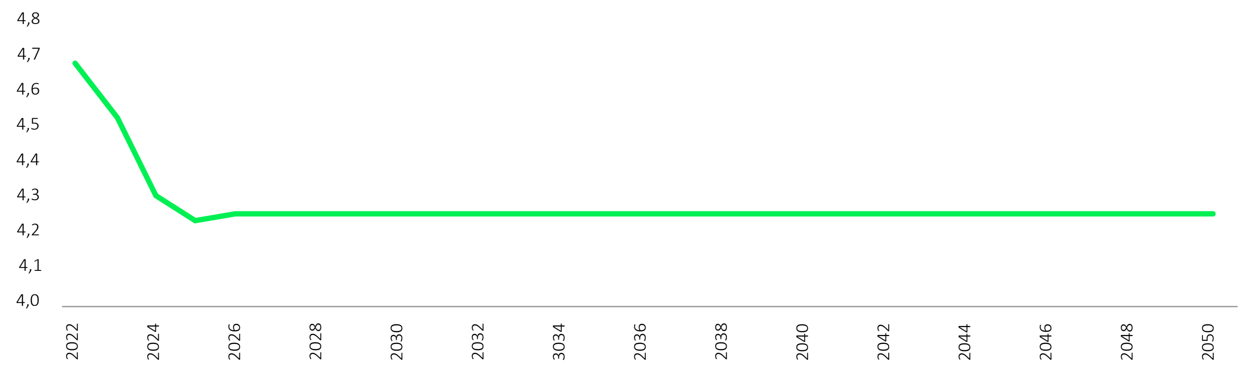


Chart 2. CPI inflation forecast Poland, *source: PTEC's own study based on data from the National Bank of Poland – Current projection of inflation and GDP (published in November 2025) and the Guidelines of the Ministry of Finance on the use of uniform macroeconomic indicators, July 2025.*

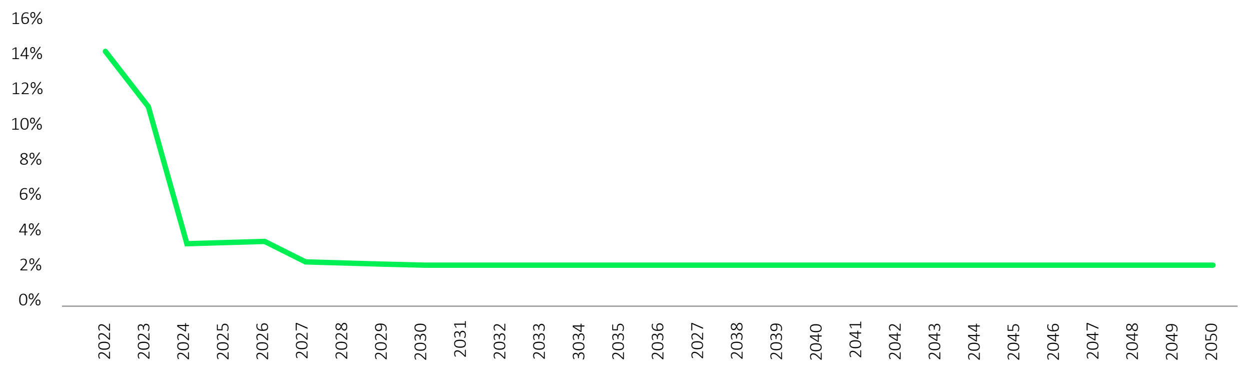


Chart 3. Hard coal price forecast [PLN/GJ] – nominal values; *source: PTEC's own study based on current quotes and report World Energy Outlook November 2025 - European Union; Stated Policies Scenario, wholesale fossil fuel prices..*

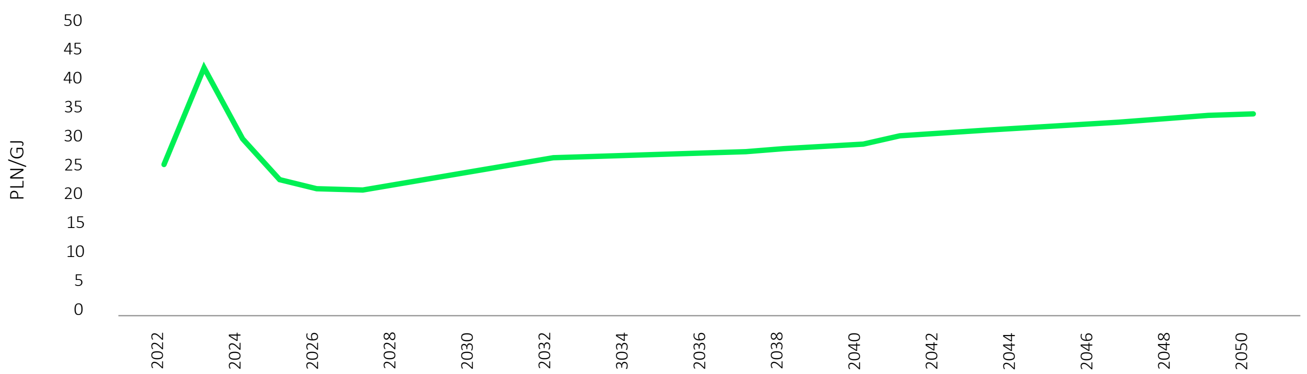


Chart 4. Natural gas price forecast [PLN/GJ], nominal values; *source: PTEC's own study based on current quotes and report World Energy Outlook November 2025 - European Union; Stated Policies Scenario, wholesale fossil fuel prices..*

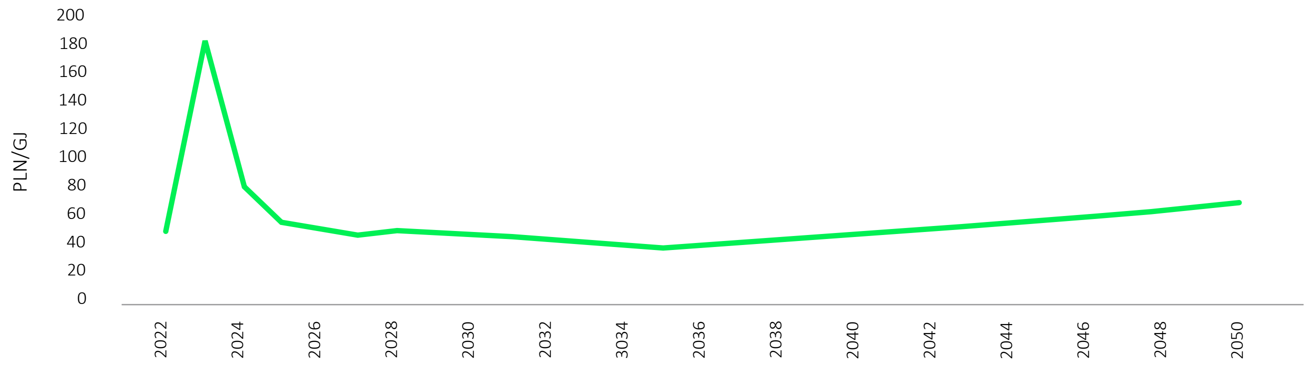


Chart 5. Biomass price forecast [PLN/GJ], nominal values; *source: PTEC's own study based on contracted data and PTEC Members' biomass price forecasts.*

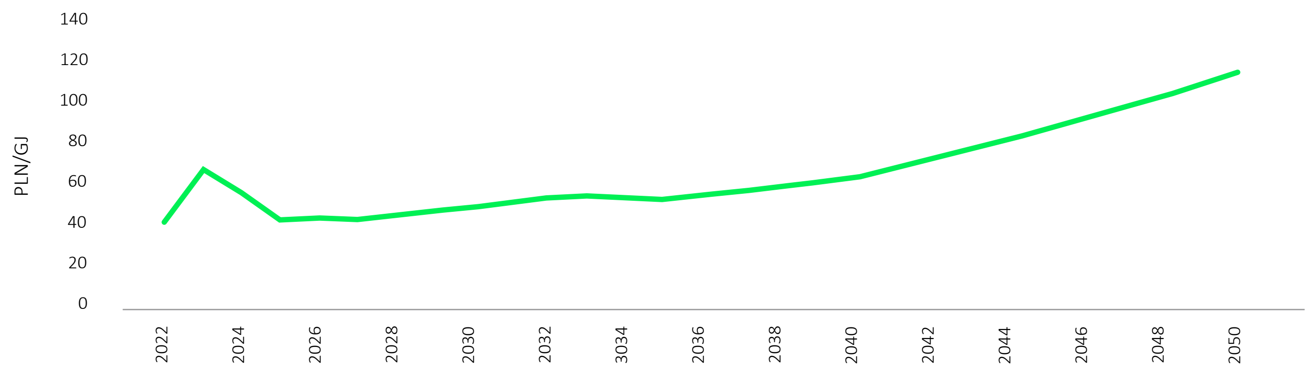


Chart 6. Price of greenhouse gas emission allowances [PLN/t], nominal values; *source: PTEC's own study based on current market prices and WEO analyses World Energy Outlook November 2025 - European Union; Stated Policies Scenario. CO_2 prices for electricity, industry and energy production..*

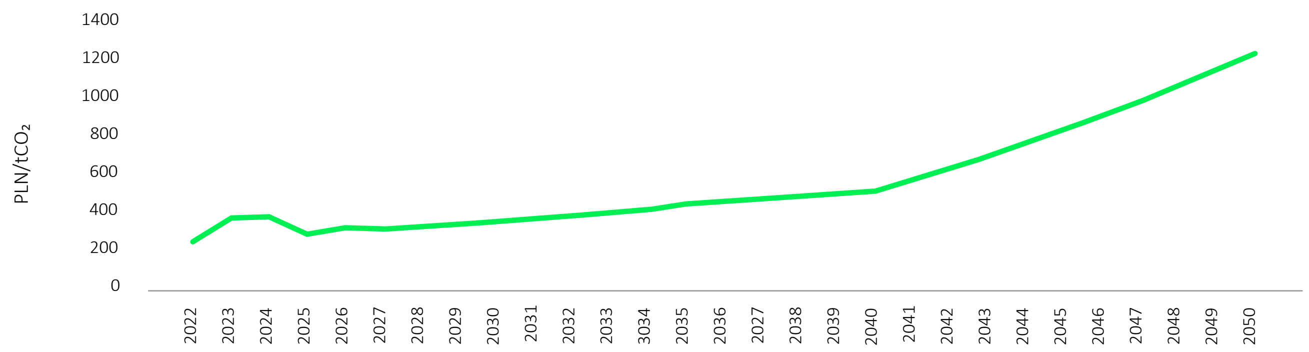
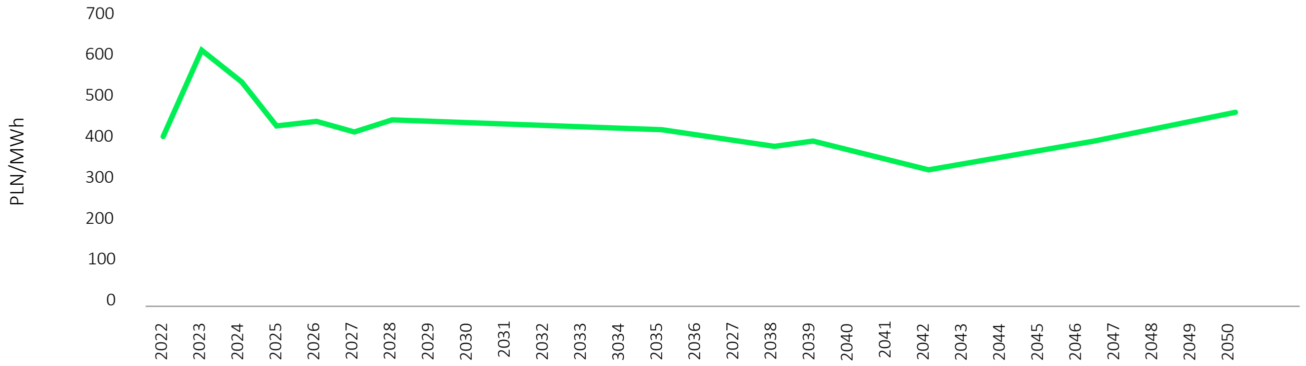


Chart 7. Forecast of electricity prices in the wholesale energy market [PLN/MWh], nominal values; *source: PTEC's own study based on the adopted cost assumptions and the assumption of a fixed electricity market margin for the more profitable technology among condensing coal-fired units and new CCGT gas units. The electricity price forecast shown in the chart in the long term takes into account anticipated changes in the fuel mix due to, among other things, the development of nuclear power and offshore wind power, as well as the gradual reduction in the operation of conventional units.*



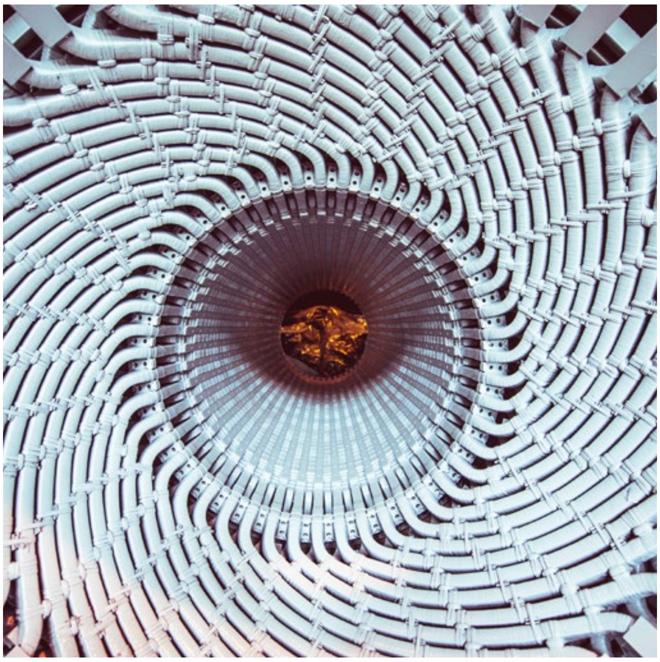
TECHNICAL AND ECONOMIC ASSUMPTIONS

Table 1: Technical and economic assumptions, source: *PTEC's own study on the basis of experience from its operations.*

Technology	Commencement of operations	CAPEX mPLN'25/MWe	CAPEX mPLN'25/MWt	CAPEX PLN'25/m³	OPEX as a % of CAPEX
Gas-fired boilers	high methane natural gas	N.A.	1.3	N.A.	1.0%
Gas-fired cogeneration – gas engines	high methane natural gas	8.0	N.A.	N.A.	5.0%
Biomass-fired boilers	biomass	N.A.	5.0	N.A.	3.0%
Heat pumps	ambient energy and electricity	N.A.	6.0	N.A.	1.0%
Electrode boilers	electricity	N.A.	1.0	N.A.	0.5%
Heat storage	N.A.	N.A.	N.A.	2 500	1.0%

Other assumptions included:

- Remuneration costs at the level of 15 thousand PLN in 2025 per month / FTE; the number of FTEs was varied depending on the technological mix in a given option.
- Weighted average cost of capital WACC of 8%.
- Corporate income tax (CIT) of 19%.
- The efficiency of the equipment is calculated individually using an hourly model based on the ambient temperature and the operating point of the equipment in question.



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